Regulatory Impact Analysis

Petroleum Refineries
New Source Performance Standards Ja

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1. EXECUTIVE SUMMARY

1.1 Introduction

On June 24, 2008, EPA promulgated amendments to the Standards of Performance for Petroleum Refineries and new standards of performance for petroleum refinery process units constructed, reconstructed, or modified after May 14, 2007. EPA subsequently received three petitions for reconsideration of these final rules. On September 26, 2008, EPA granted reconsideration and issued a stay for the issues raised in the petitions regarding process heaters and flares. On December 22, 2008, EPA addressed those specific issues by proposing amendments to certain provisions for process heaters and flares. This final regulation includes emissions limits for new and modified/reconstructed sources, and these limits are set for sulfur dioxide (SO_2), nitrogen oxides (NO_x), volatile organic compounds (VOC), and other pollutants.

The petroleum refining industry comprises establishments primarily engaged in refining crude petroleum into refined petroleum. Examples of refined petroleum products include gasoline, kerosene, asphalt, lubricants, solvents, and a variety of other products. Petroleum refining falls under the North American Industrial Classification System (NAICS) 324110.

This regulatory impact analysis (RIA) was prepared in response to requirements under Executive Order 12866. The RIA presents the results of analyses undertaken in support of this final rule including compliance costs, benefits, economic impacts, and impacts to small businesses. This RIA is organized as follows:

- Section 1: Executive Summary,
- Section 2 and an Appendix A: Profile of the Petroleum Refining Industry,
- Section 3: NSPS Regulatory Alternatives, and Costs and Emission Reductions From Complying with the NSPS,
- Section 4: Economic Impact Analysis: Methods and Results,
- Section 5: Executive Orders,
- Section 6: Benefits of the NSPS, and
- Section 7: Comparison of Benefits and Costs.

1.2 Results

EPA has characterized the facilities and companies potentially affected by the NSPS by examining existing refineries and the companies that own them. EPA projects that new refineries and processes will be similar to existing ones, and that the companies owning new sources will also be similar to the companies owning existing refineries. EPA has collected data on 148 existing refineries, owned by 64 companies. Of the affected parent companies, thirty-six are identified as small entities based on the Small Business Administration size standard criteria for NAICS 324110, for they employ 1,500 or fewer employees.

The total annualized engineering compliance costs of the NSPS are estimated at $96 million. The total annual savings from offset natural gas purchases and product recovery credits that arise as a result of complying with the rule are estimated at $180 million. EPA estimates that complying with the final NSPS will yield an annualized cost savings of approximately $79 million per year (2006 dollars) in 2017. The estimated nationwide 5-year incremental emissions reductions and cost impacts for the final standards are summarized in Table 1-1 below. Given that there are cost savings, EPA anticipates that the NSPS will have no negative impacts on the market for petroleum products. Based on sales data obtained for the affected small entities, as well as expected annualized cost savings, EPA estimates that the NSPS will not result in a SISNOSE (significant economic impact on a substantial number of small entities).

Table 1-1. National Incremental Cost Impacts, Emission Reductions, and Cost Effectiveness for Petroleum Refinery Flares Subject to Amended Standards Under 40 CFR part 60, subpart Ja (Fifth Year After Effective Date of Final Rule Amendments)[1]

	Subpart Ja Requirements	Total capital cost (millions)	Total annual cost without credit (millions/yr)	Natural gas offset/ product recovery credit (millions)	Total annual cost (millions/yr)	Annual emission reductions (tons SO_2/yr)	Annual emission reductions (tons NO_X/yr)	Annual emission reductions (tons VOC/yr)	Cost effective-ness ($/ton emissions reduced)	Annual emission reductions (metric tons CO_2/yr)[2]	Monetized Benefits (millions, 3% discount rate for health and climate benefits)			Monetized Benefits (millions, 3% discount rate for health and 7% for climate benefits)		
Small Flares	Flare Monitoring	$72	$12	$0	$12	0	0	0		0	$0	to	$0	$0	to	$0
	Flare gas recovery	$0	$0	$0	$0	0	0	0		0	$0	to	$0	$0	to	$0
	Flare Management	$0	$0.79	$0	$0.79	0	0	270	$2,900	0	$0	to	$0	$0	to	$0
	SO2 RCA/CA	$0	$1.9	$0	$1.9	2,600	0	0	$760	0	$170	to	$410	$150	to	$370
	Flowrate RCA/CA	$0	$0.90	-$6.7	-$5.8	3.4	50	390	-$13,000	98,000	$2.9	to	$3.7	$2.9	to	$3.6
	Total	**$72**	**$16**	**-$6.7**	**$9.0**	**2,600**	**50**	**660**	**$2,700**	**98,000**	**$170**	**to**	**$410**	**$150**	**to**	**$370**
Large Flares	Flare Monitoring	$12	$2.0	$0	$2.0	0	0	0		0	$0	to	$0	$0	to	$0
	Flare gas recovery	$380	$78	-$170	-$90	380	1,100	2,700	-$22,000	1,800,000	$74	to	$120	$71	to	$110
	Flare Management	$0	$0.088	$0	$0.088	0	0	30	$2,900	0	$0	to	$0	$0	to	$0
	SO2 RCA/CA	$0	$0.22	$0	$0.22	290	0	0	$760	0	$18	to	$45	$17	to	$41
	Flowrate RCA/CA	$0	$0.10	-$0.74	-$0.64	0	6	43	-$13,000	11,000	$0	to	$0	$0	to	$0
	Total	**$390**	**$81**	**-$170**	**-$88**	**660**	**1,100**	**2,800**	**-$20,000**	**1,800,000**	**$93**	**to**	**$160**	**$88**	**to**	**$150**
All Flares	Flare Monitoring	$84	$14	$0	$14	0	0	0		0	$0	to	$0	$0	to	$0
	Flare gas recovery	$380	$78	-$170	-$90	380	1,100	2,700	-$22,000	1,800,000	$74	to	$120	$71	to	$110
	Flare Management	$0	$0.88	$0	$0.88	0	0	300	$2,900	0	$0	to	$0	$0	to	$0
	SO2 RCA/CA	$0	$2.2	$0	$2.2	2,900	0	0	$760	0	$180	to	$450	$170	to	$410
	Flowrate RCA/CA	$0	$1.00	-$7.4	-$6.4	3.4	56	430	-$13,000	110,000	$3.2	to	$4.0	$3.1	to	$3.9
	Total	**$460**	**$96**	**-$180**	**-$79**	**3,200**	**1,100**	**3,400**	**-$10,000**	**1,900,000**	**$260**	**to**	**$580**	**$240**	**to**	**$520**

[1]All estimates are for the implementation year (2017), and are rounded to two significant figures.
[2] The emission reductions of CO_2 reflect the anticipated emission increases associated with the energy disbenefits from additional electricity consumption.

EPA estimates that the total monetized benefits of the final NSPS are $260 million to $580 million and $240 million to $520 million, at 3% and 7% discount rates, respectively (Table 1-2). All estimates are in 2006 dollars for the year 2017. Using alternate relationships between $PM_{2.5}$ and premature mortality supplied by experts, higher and lower benefits estimates are plausible, but most of the expert-based estimates fall between these estimates. In addition, direct exposure to SO_2 and NOx benefits, ozone benefits, ecosystem benefits, and visibility benefits have not been monetized in this analysis.

EPA estimates the net benefits of the final NSPS are $340 million to $660 million and $320 million to $600 million, at 3% and 7% discount rates, respectively (Table 1-2). All estimates are in 2006 dollars for the year 2017.

Table 1-2. Summary of the Monetized Benefits, Social Costs, and Net Benefits for the Final Petroleum Refineries NSPS in 2017 (millions of 2006$)[1]

	3% Discount Rate			7% Discount Rate		
	Final Major Source NSPS					
Total Monetized Benefits[2]	$260	to	$580	$240	to	$520
Total Compliance Costs[3]		-$79			-$79	
Net Benefits	$340	to	$660	$320	to	$600
Non-monetized Benefits	Health effects from SO_2, NO_2, and ozone exposure Health effects from PM exposure from VOCs Ecosystem effects Visibility impairment					

[1] All estimates are for the implementation year (2017), and are rounded to two significant figures.

[2] The total monetized benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of $PM_{2.5}$ precursors such as NOx and SO_2 as well as CO_2 benefits. It is important to note that the monetized benefits do not include the reduced health effects from direct exposure to SO_2 and NOx, ozone exposure, ecosystem effects, or visibility impairment. Human health benefits are shown as a range from Pope et al. (2002) to Laden et al. (2006). These models assume 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 effects estimates by particle type. The net present value of reduced CO_2 emissions is calculated differently than other benefits. This table includes monetized climate benefits using the global average social cost of carbon (SCC) estimated at a 3 percent discount rate because the interagency workgroup deemed the SCC estimate at a 3 percent discount rate to be the central value.

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

Alternatively, if no refineries install flare gas recovery systems, EPA estimates the costs would be $10.7 million with monetized benefits of $190 to $460 million and $170 to $410 million at a discount rates of 3% and 7% respectively. Thus, net benefits without flare gas recovery systems would be $180 million to $450 million and $160 million to $400 million, at 3% and 7% discount rates, respectively. All estimates are in 2006 dollars for the year 2017.

For small flares, we estimate the monetized benefits are $170 million to $410 million (3-percent discount rate) and $150 million to $370 million (7% discount rate for health benefits and 3% discount rate for climate benefits). For large flares, we estimate the monetized benefits are $93 million to $160 million (3% discount rate) and $88 million to $150 million (7% discount rate for health benefits and 3-percent discount rate for climate benefits). All estimates are in 2006 dollars for the year 2017.

1.3 References

Laden, F., J. Schwartz, F.E. Speizer, and D.W. Dockery. 2006. Reduction in Fine Particulate Air Pollution and Mortality. *American Journal of Respiratory and Critical Care Medicine.* 173: 667-672.

Office of Management and Budget. Circular A-4, September 17, 2003. Available on the Internet at http://www.whitehouse.gov/omb/circulars_a004_a-4.

Pope, C.A., III, R.T. Burnett, M.J. Thun, E.E. Calle, D. Krewski, K. Ito, and G.D. Thurston. 2002. "Lung Cancer, Cardiopulmonary Mortality, and Long-term Exposure to Fine Particulate Air Pollution." *Journal of the American Medical Association* 287:1132-1141.

2. PROFILE OF THE PETROLEUM REFININGINDUSTRY

2.1 Introduction

This industry profile of the petroleum refining industry provides information that will support this and subsequent regulatory impact analyses (RIAs) and economic impact analyses (EIAs) that will assess the impacts of these standards.

At its core, the petroleum refining industry comprises establishments primarily engaged in refining crude petroleum into finished petroleum products. Examples of these petroleum products include gasoline, kerosene, asphalt, lubricants, and solvents, among others.

Firms engaged in petroleum refining are categorized under the North American Industry Classification System (NAICS) code 324110. In 2010, 148 establishments owned by 64 parent companies were refining petroleum in the continental United States. In 2009, the petroleum refining industry shipped products valued at over $436 billion (U.S. Census Bureau, Sector 31: 2009 and 2008).

This industry profile report is organized as follows. Section 2.2 provides a detailed description of the inputs, outputs, and processes involved in petroleum refining. Section 2.3 describes the applications and users of finished petroleum products. Section 2.4 discusses the organization of the industry and provides facility- and company-level data. In addition, small businesses are reported separately for use in evaluating the impact on small business to meet the requirements of the Small Business Regulatory Enforcement and Fairness Act (SBREFA). Section 2.5 contains market-level data on prices and quantities and discusses trends and projections for the industry.

2.2 The Supply Side

Estimating the economic impacts of any regulation on the petroleum refining industry requires a good understanding of how finished petroleum products are produced (the "supply side" of finished petroleum product markets). This section describes the production process used to manufacture these products as well as the inputs, outputs, and by-products involved. The section concludes with a description of costs involved with the production process.

2.2.1 Production Process, Inputs, and Outputs

Petroleum pumped directly out of the ground, known as crude oil, is a complex mixture of hydrocarbons (chemical compounds that consist solely of hydrogen and carbon) and various impurities such as salt. To manufacture the variety of petroleum products recognized in everyday

life, this mixture must be refined and processed over several stages. This section describes the typical stages involved in this process as well as the inputs and outputs.

2.2.1.1 The Production Process

The process of refining crude oil into useful petroleum products can be separated into two phases and a number of supporting operations. These phases are described in detail in the following section. In the first phase, crude oil is desalted and then separated into its various hydrocarbon components (known as "fractions"). These fractions include gasoline, kerosene, naphtha, and other products (EPA, 1995).

In the second phase, the distilled fractions are converted into petroleum products (such as gasoline and kerosene) using three different types of downstream processes: combining, breaking, and reshaping (EPA, 1995). An outline of the refining process is presented in Figure 2-1.

Desalting. Before separation into fractions, crude oil is treated to remove salts, suspended solids, and other impurities that could clog or corrode the downstream equipment. This process, known as "desalting," is typically done by first heating the crude oil, mixing it with process water, and depositing it into a gravity settler tank. Gradually, the salts present in the oil will be dissolved into the process water (EPA, 1995). After this takes place, the process water is separated from the oil by adding demulsifier chemicals (a process known as chemical separation) and/or by applying an electric field to concentrate the suspended water globules at the bottom of the settler tank (a process known as electrostatic separation). The effluent water is then removed from the tank and sent to the refinery wastewater treatment facilities (EPA, 1995). This process is illustrated in Figure 2-2.

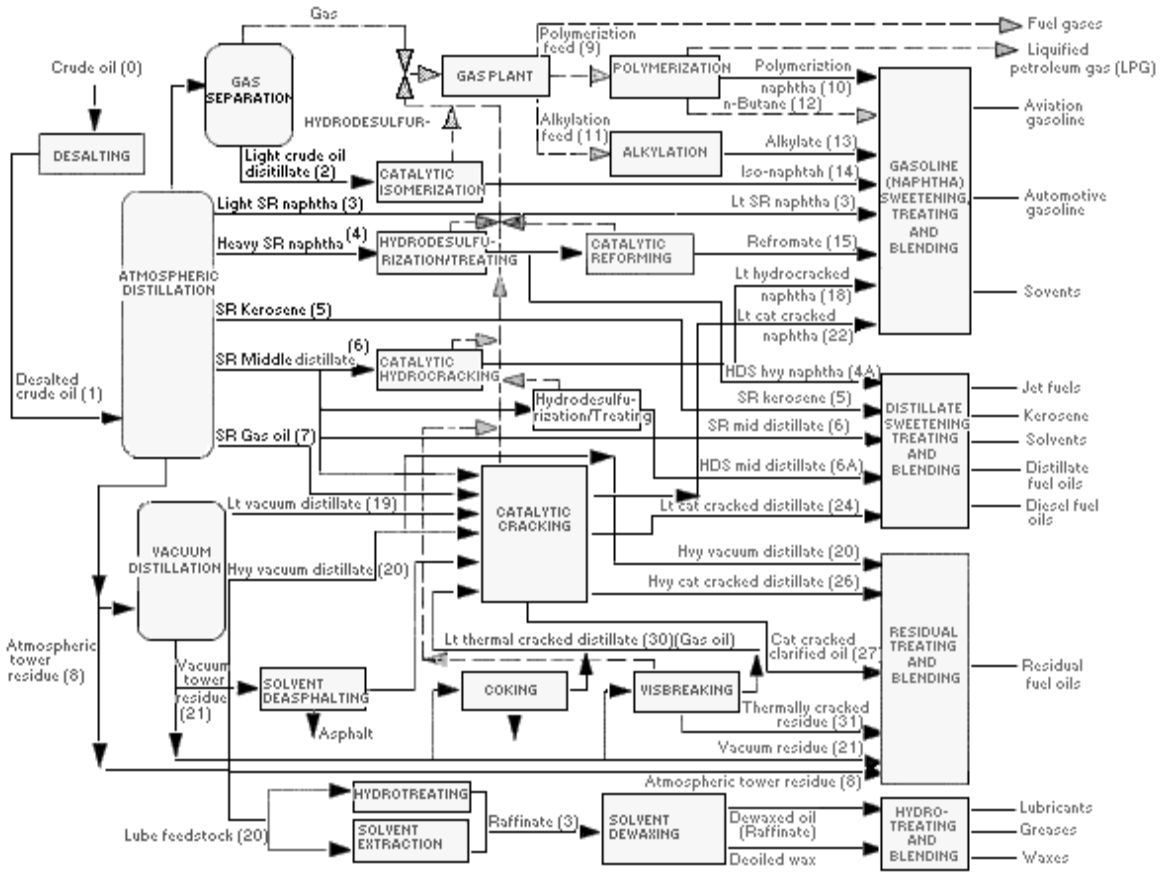

Figure 2-1 Outline of the Refining Process

Source: U.S. Department of Labor, Occupational Safety and Health Administration (OSHA). 2003. OSHA Technical Manual, Section IV: Chapter 2, Petroleum Refining Processes. TED 01-00-015. Washington, DC: U.S. DOL. Available at <http://www.osha.gov/dts/osta/otm/otm_iv/otm_iv_2.html>. As obtained on October 23, 2006.

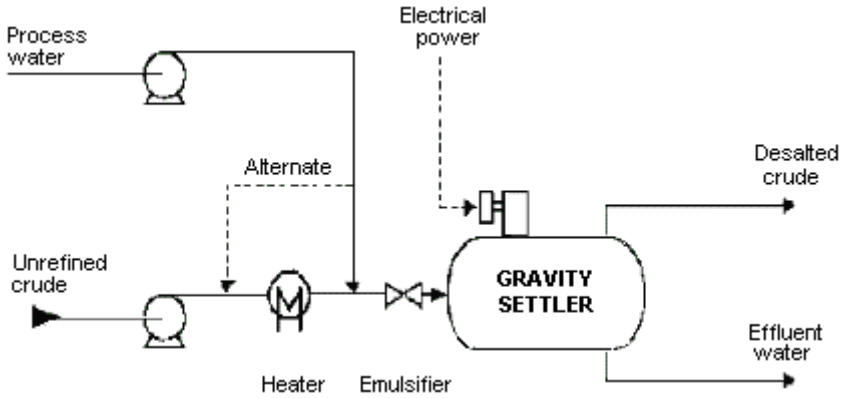

Figure 2-2 Desalting Process

Source: U.S. Department of Labor, Occupational Safety and Health Administration (OSHA). 2003. OSHA Technical Manual, Section IV: Chapter 2, Petroleum Refining Processes. TED 01-00-015. Washington, DC: U.S. DOL. Available at <http://www.osha.gov/dts/osta/otm/otm_iv/otm_iv_2.html>. As obtained on October 23, 2006.

Atmospheric Distillation. The desalted crude oil is then heated in a furnace to 750°F and fed into a vertical distillation column at atmospheric pressure. After entering the tower, the lighter fractions flash into vapor and travel up the tower. This leaves only the heaviest fractions (which have a much higher boiling point) at the bottom of the tower. These fractions include heavy fuel oil and asphalt residue (EPA, 1995).

As the hot vapor rises, its temperature is gradually reduced. Lighter fractions condense onto trays located at successively higher portions of the tower. For example, motor gasoline will condense at higher portion of the tower than kerosene because it condenses at lower temperatures. This process is illustrated in Figure 2-3. As these fractions condense, they will be drawn off their respective trays and potentially sent downstream for further processing (OSHA, 2003; EPA, 1995).

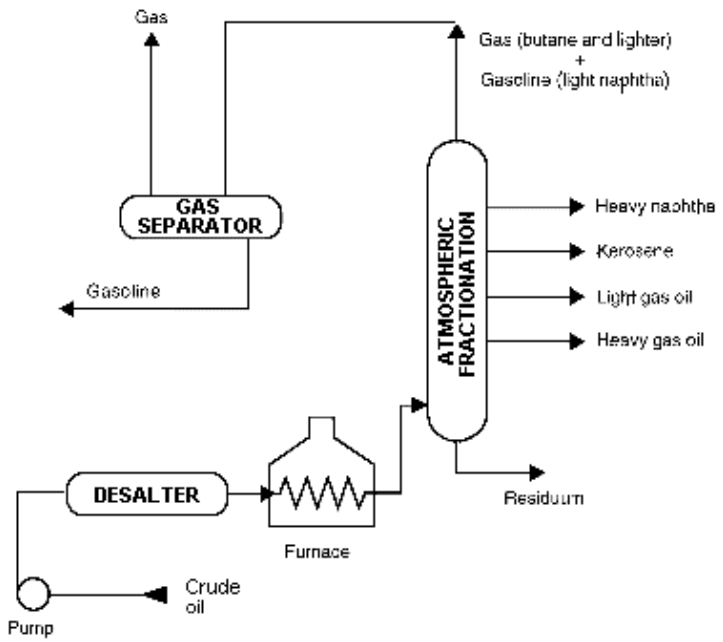

Figure 2-3 Atmospheric Distillation Process

Source: U.S. Department of Labor, Occupational Safety and Health Administration (OSHA). 2003. OSHA Technical Manual, Section IV: Chapter 2, Petroleum Refining Processes. TED 01-00-015. Washington, DC: U.S. DOL. Available at <http://www.osha.gov/dts/osta/otm/otm_iv/otm_iv_2.html>. As obtained on October 23, 2006.

Vacuum Distillation. The atmospheric distillation tower cannot distill the heaviest fractions (those at the bottom of the tower) without cracking under requisite heat and pressure. So these fractions are separated using a process called vacuum distillation. This process takes place in one or more vacuum distillation towers and is similar to the atmospheric distillation process, except very low pressures are used to increase volatilization and separation. A typical first-phase vacuum tower may produce gas oils or lubricating-oil base stocks (EPA, 1995). This process is illustrated in Figure 2-4.

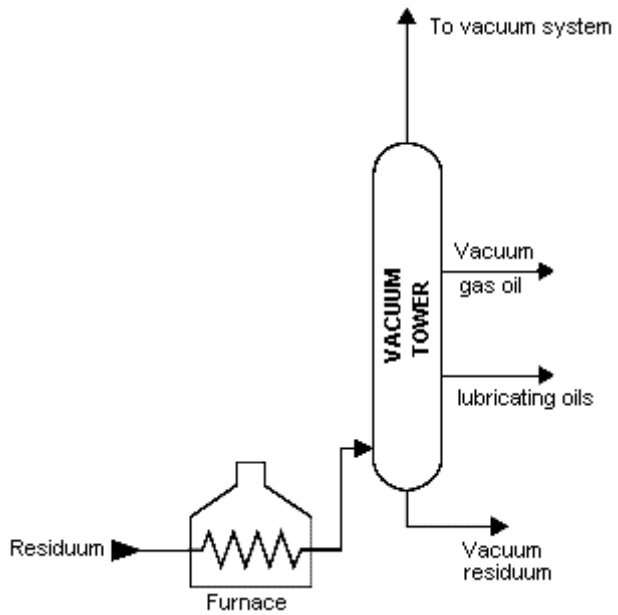

Figure 2-4 Vacuum Distillation Process

Source: U.S. Department of Labor, Occupational Safety and Health Administration (OSHA). 2003. OSHA Technical Manual, Section IV: Chapter 2, Petroleum Refining Processes. TED 01-00-015. Washington, DC: U.S. DOL. Available at <http://www.osha.gov/dts/osta/otm/otm_iv/otm_iv_2.html>. As obtained on October 23, 2006.

Downstream Processing. To produce the petroleum products desired by the market place, most fractions must be further refined after distillation or "downstream" processes. These downstream processes change the molecular structure of the hydrocarbon molecules by breaking them into smaller molecules, joining them to form larger molecules, or shaping them into higher quality molecules (EPA, 1995).

Downstream processes include thermal cracking, coking, catalytic cracking, catalytic hydrocracking, hydrotreating, alkylation, isomerization, polymerization, catalytic reforming, solvent extraction, merox, dewaxing, propane deasphalting and other operations (EPA, 1995).

2.2.1.2 Supporting Operations

In addition to the processes described above, there are other refinery operations that do not directly involve the production of hydrocarbon fuels, but serve in a supporting role. Some of the major supporting operations are described in this section.

Wastewater Treatment. Petroleum refining operations produce a variety of wastewaters including process water (water used in process operations like desalting), cooling water (water used for cooling that does not come into direct contact with the oil), and surface water runoff (resulting from spills to the surface or leaks in the equipment that have collected in drains).

Wastewater typically contains a variety of contaminants (such as hydrocarbons, suspended solids, phenols, ammonia, sulfides, and other compounds) and must be treated before it is recycled back into refining operations or discharged. Petroleum refineries typically utilize two stages of wastewater treatment. In primary wastewater treatments, oil and solids present in the wastewater are removed. After this is completed, wastewater can be discharged to a publicly owned treatment facility or undergo secondary treatment before being discharged directly to surface water. In secondary treatment, microorganisms are used to dissolve oil and other organic pollutants that are present in the wastewater (EPA, 1995; OSHA, 2003).

Gas Treatment and Sulfur Recovery. Petroleum refinery operations such as coking and catalytic cracking emit gases with a high concentration of hydrogen sulfide mixed with light refinery fuel gases (such as methane and ethane). Sulfur must be removed from these gases in order to comply with the Clean Air Act's SO_x emission limits and to recover saleable elemental sulfur.

Sulfur is recovered by first separating the fuel gases from the hydrogen sulfide gas. Once this is done, elemental sulfur is removed from the hydrogen sulfide gas using a recovery system known as the Claus Process. In this process, hydrogen sulfide is burned under controlled conditions producing sulfur dioxide. A bauxite catalyst is then used to react with the sulfur dioxide and the unburned hydrogen sulfide to produce elemental sulfur. However, the Claus process only removes 90% of the hydrogen sulfide present in the gas stream, so other processes must be used to recover the remaining sulfur (EPA, 1995).

Additive Production. A variety of chemicals are added to petroleum products to improve their quality or add special characteristics. For example, ethers have been added to gasoline to increase octane levels and reduce CO emissions since the 1970s.

Heat Exchangers, Coolers, and Process Heaters. Petroleum refineries require very high temperatures to perform many of their refining processes. To achieve these temperatures, refineries use fired heaters fueled by refinery or natural gas, distillate, and residual oils. This heat is managed through heat exchangers, which are composed of bundles of pipes, tubes, plate coils, and other equipment that surround heating or cooling water, steam, or oil. Heat exchangers facilitate the indirect transfer of heat as needed (OSHA, 2003).

Pressure Release and Flare Systems. As liquids and gases expand and contract through the refining process, pressure must be actively managed to avoid accident. Pressure-relief systems enable the safe handling of liquids and gases that are released by pressure-relieving

devices and blow-downs. According to the OSHA Technical Manual, "pressure relief is an automatic, planned release when operating pressure reaches a predetermined level. A blow-down normally refers to the intentional release of material, such as blow-downs from process unit startups, furnace blow-downs, shutdowns, and emergencies" (OSHA, 2003).

Blending. Blending is the final operation in petroleum refining. It is the physical mixture of a number of different liquid hydrocarbons to produce final petroleum products that have desired characteristics. For example, additives such as ethers can be blended with motor gasoline to boost performance and reduce emissions. Products can be blended in-line through a manifold system, or batch blended in tanks and vessels (OSHA, 2003).

2.2.1.3 Inputs

The inputs in the production process of petroleum products include general inputs such as labor, capital, and water.[1] The inputs specific to this industry are crude oil and the variety of chemicals used in producing petroleum products. These two specific inputs are discussed below.

Crude Oil. Crude oils are complex, heterogeneous mixtures and contain many different hydrocarbon compounds that vary in appearance and composition from one oil field to another. An "average" crude oil contains about 84% carbon; 14% hydrogen; and less than 2% sulfur, nitrogen, oxygen, metals, and salts (OSHA, 2003). The proportions of crude oil elements vary over a narrow limit: the proportion of carbon ranges from 83 to 87 percent; hydrogen ranges from 10 to 14 percent; nitrogen ranges from 0.1 to 2 percent; oxygen ranges from 0.5 to 1.5 percent; and sulfur ranges from 0.5 to 6 percent (Speight 2006).

In 2010, the petroleum refining industry used 5.4 billion barrels of crude oil in the production of finished petroleum products (EIA 2010).[2]

Common Refinery Chemicals. In addition to crude oil, a variety of chemicals are used in the production of petroleum products. The specific chemicals used will depend on specific characteristics of the product in question. Table 2-1 lists the most common chemicals used by petroleum refineries, their characteristics, and their applications.

Table 2-1 Types and Characteristics of Raw Materials used in Petroleum Refineries

[1] Crude oil processing requires large volumes of water, a large portion of which is continually recycled. The amount of water used by a refinery can vary significantly, depending on process configuration, refinery complexity, capability for recycle, degree of sewer segregation, and local rainfall. In 1992, the average amount of water used in refineries was estimated between 65 and 90 gallons per barrel of crude oil processed (OGJ 1992a).
[2] A barrel is a unit of volume that is equal to 42 U.S. gallons.

Type	Description
Crude Oil	Heterogeneous mixture of different hydrocarbon compounds.
Oxygenates	Substances which, when added to gasoline, increase the amount of oxygen in that gasoline blend. Ethanol, ethyl tertiary butyl ether (ETBE), and methanol are common oxygenates.
Caustics	Caustics are added to desalting water to neutralize acids and reduce corrosion. They are also added to desalted crude in order to reduce the amount of corrosive chlorides in the tower overheads. They are used in some refinery treating processes to remove contaminants from hydrocarbon streams.
Leaded Gasoline Additives	Tetraethyl lead (TEL) and tetramethyl lead (TML) are additives formerly used to improve gasoline octane ratings but are no longer in common use except in aviation gasoline.
Sulfuric Acid and Hydrofluoric Acid	Sulfuric acid and hydrofluoric acid are used primarily as catalysts in alkylation processes. Sulfuric acid is also used in some treatment processes.

Source: U.S. Department of Labor, Occupational Safety and Health Administration (OSHA). 2003. OSHA Technical Manual, Section IV: Chapter 2, Petroleum Refining Processes. TED 01-00-015. Washington, DC: U.S. DOL. Available at <http://www.osha.gov/dts/osta/otm/otm_iv/otm_iv_2.html>. As obtained on October 23, 2006.

In 2010, the petroleum refining industry used 971 million barrels of natural gas liquids and other liquids in the production of finished petroleum products (EIA 2010).

2.2.1.4 Types of Product Outputs

The petroleum refining industry produces a number of products that fall into one of three categories: fuels, finished nonfuel products, and feedstock for the petrochemical industry. Table 2-2 briefly describes these product categories. A more detailed discussion of petroleum fuel products can be found in Section 2.3.

Table 2-2 Refinery Product Categories

Product Category	Description
Fuels	Finished Petroleum products that are capable of releasing energy. These products power equipment such as automobiles, jets, and ships. Typical petroleum fuel products include gasoline, jet fuel, and residual fuel oil.
Finished nonfuel products	Petroleum products that are not used for powering machines or equipment. These products typically include asphalt, lubricants (such as motor oil and industrial greases), and solvents (such as benzene, toluene, and xylene).
Feedstock	Many products derived from crude oil refining, such as ethylene, propylene, butylene, and isobutylene, are primarily intended for use as petrochemical feedstock in the production of plastics, synthetic fibers, synthetic rubbers, and other products.
Sulfur	Commercial uses are primarily in fertilizers, because of the relatively high requirement of plants for it, and in the manufacture of sulfuric acid, a primary industrial chemical.

Source: U.S. Department of Labor, Occupational Safety and Health Administration (OSHA). 2003. OSHA Technical Manual, Section IV: Chapter 2, Petroleum Refining Processes. TED 01-00-015. Washington, DC: U.S. DOL. Available at <http://www.osha.gov/dts/osta/otm/otm_iv/otm_iv_2.html>. As obtained on October 23, 2006.

2.2.2 Emissions and Controls in Petroleum Refining

Petroleum refining results in emissions of hazardous air pollutants (HAPs), criteria air pollutants (CAPs), and other pollutants. The HAPs include metals and toxic organic compounds; the CAPs include carbon monoxide (CO), sulfur oxides (SO_x), nitrogen oxides (NO_x), particulates, and volatile organic compounds (VOCs); and the other pollutants include spent acids, gaseous pollutants, ammonia (NH_3), and hydrogen sulfide (H_2S).

2.2.2.1 Gaseous and VOC Emissions

As previously mentioned, CO, SO_x, NO_x, NH_3, and H_2S emissions are produced along with petroleum products. Sources of these emissions from refineries include fugitive emissions of the volatile constituents in crude oil and its fractions, emissions from the burning of fuels in process heaters, and emissions from the various refinery processes themselves. Fugitive emissions occur as a result of leaks throughout the refinery and can be reduced by purchasing leak-resistant equipment and maintaining an ongoing leak detection and repair program (EPA, 1995).

The numerous process heaters used in refineries to heat process streams or to generate steam (boilers) for heating or other uses can be potential sources of SO_x, NO_x, CO, and hydrocarbons emissions. Emissions are low when process heaters are operating properly and using clean fuels such as refinery fuel gas, fuel oil, or natural gas. However, if combustion is not complete, or the heaters are fueled using fuel pitch or residuals, emissions can be significant (EPA, 1995).

The majority of gas streams exiting each refinery process contain varying amounts of refinery fuel gas, H_2S, and NH_3. These streams are directed to the gas treatment and sulfur recovery units described in the previous section. Here, refinery fuel gas and sulfur are recovered using a variety of processes. These processes create emissions of their own, which normally contain H_2S, SO_x, and NO_x gases (EPA, 1995). For additional details on refinery fuel, or waste, gas composition, see Table 12 of the January 25, 2012 *Impact Estimates for Fuel Gas Combustion Device and Flare Regulatory Options for Amendments to the Petroleum Refinery NSPS* available in the docket.

Emissions can also be created by the periodic regeneration of catalysts that are used in downstream processes. These processes generate streams that may contain relatively high levels of CO, particulate, and VOC emissions. However, these emissions are treated before being discharged to the atmosphere. First, the emissions are processed through a CO boiler to burn CO and any VOC, and then through an electrostatic precipitator or cyclone separator to remove particulates (EPA, 1995).

2.2.2.2 Wastewater and Other Wastes

Petroleum refining operations produce a variety of wastewaters including process water (water used in process operations like desalting), cooling water (water used for cooling that does not come into direct contact with the oil), and surface water runoff (resulting from spills to the surface or leaks in the equipment that have collected in drains). This wastewater typically contains a variety of contaminants (such as hydrocarbons, suspended solids, phenols, NH_3, sulfides, and other compounds) and is treated in on-site facilities before being recycled back into the production process or discharged.

Other wastes include forms of sludges, spent process catalysts, filter clay, and incinerator ash. These wastes are controlled through a variety of methods including incineration, land filling, and neutralization, among other treatment methods (EPA, 1995).

2.2.3 Costs of Production

Between 1995 and 2009, expenditures on input materials accounted for the largest cost to petroleum refineries—amounting to 95% of total expenses (Figure 2-5). These material costs included the cost of all raw materials, containers, scrap, and supplies used in production or repair during the year, as well as the cost of all electricity and fuel consumed.

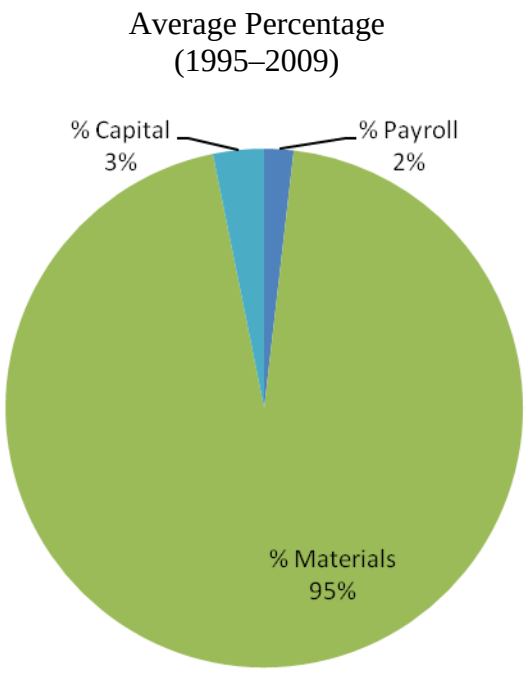

Figure 2-5 Petroleum Refinery Expenditures

Sources: U.S. Department of Commerce, Bureau of the Census. 2007. 2006 Annual Survey of Manufactures. Obtained through American Fact Finder Database <http://factfinder.census.gov/home/saff/main.html?_lang=en>.

U.S. Department of Commerce, Bureau of the Census. 2006. *2005 Annual Survey of Manufacture*s. M05(AS)-1. Washington, DC: Government Printing Office. Available at <http://www.census.gov/prod/2006pubs/

U.S. Department of Commerce, Bureau of the Census. 2003a. *2001 Annual Survey of Manufacture*s. M01(AS)-1. Washington, DC: Government Printing Office. Available at <http://www.census.gov/prod/2003pubs/

U.S. Department of Commerce, Bureau of the Census. 2001. *1999 Annual Survey of Manufacture*s. M99(AS)-1 (RV). Washington, DC: Government Printing Office. Available at <http://www.census.gov/prod/2001pubs/

U.S. Department of Commerce, Bureau of the Census. 1998. *1996 Annual Survey of Manufacture*s. M96(AS)-1 (RV). Washington, DC: Government Printing Office. Available at <http://www.census.gov/prod/3/98pubs/

U.S. Department of Commerce, Bureau of the Census. 1997. *1995 Annual Survey of Manufacture*s. M95(AS)-1. Washington, DC: Government Printing Office. Available at <http://www.census.gov/prod/2/manmin/

U.S. Census Bureau, American FactFinder; "Sector 31: Annual Survey of Manufactures: General Statistics: Statistics for Industry Groups and Industries: 2009 and 2008 " Release Date: 12/3/10; (Data accessed on 10/10/11). [Source for 2008 and 2009 numbers] http://factfinder.census.gov/servlet/IBQTable?_bm=y&-NAICSASM=324110&-ds_name=AM0931GS101&-ib_type=NAICSASM&-_industry=324110&-_lang=en

U.S. Census Bureau, American FactFinder; "Sector 31: Manufacturing: Industry Series: Detailed Statistics by Industry for the United States: 2007" Release Date 10/30/09; (Data accessed on 10/11/11). [Source for 2007 numbers] http://factfinder.census.gov/servlet/IBQTable?_bm=y&-geo_id=01000US&-ds_name=EC0731I1&-NAICS2007=324110&-_lang=en

Labor and capital accounted for the remaining expenses faced by petroleum refiners. Capital expenditures include permanent additions and alterations to facilities and machinery and equipment used for expanding plant capacity or replacing existing machinery. A detailed breakdown of how much petroleum refiners spent on each of these factors of production over this 15-year period is provided in Table 2-3. A more exhaustive assessment of the costs of materials used in petroleum refining is provided in Table 2-4.

Table 2-3 Labor, Material, and Capital Expenditures for Petroleum Refineries (NAICS 324110)

	Payroll ($millions)		Materials ($millions)		Total Capital ($millions)	
Year	**Reported**	**2005**	**Reported**	**2005**	**Reported**	**2005**
1995	3,791	4,603	112,532	136,633	5,937	7,209
1996	3,738	4,435	132,880	157,658	5,265	6,247
1997	3,885	4,595	127,555	150,865	4,244	5,020
1998	3,695	4,415	92,212	110,187	4,169	4,982
1999	3,983	4,682	114,131	134,146	3,943	4,635
2000	3,992	4,509	180,568	203,967	4,685	5,292
2001	4,233	4,743	158,733	177,838	6,817	7,638
2002	4,386	4,947	166,368	187,646	5,152	5,811
2003	4,752	5,227	185,369	203,893	6,828	7,510
2004	5,340	5,635	251,467	265,369	6,601	6,966
2005	5,796	5,796	345,207	345,207	10,525	10,525
2006	5,984	5,751	396,980	381,546	11,175	10,741
2007	6,357	5,885	470,946	435,965	17,105	15,834
2008	6,313	5,415	649,784	557,380	17,660	15,148
2009	6,400	5,776	398,679	359,790	16,824	15,183

Note: Adjusted for inflation using the producer price index industry for total manufacturing industries (Table 5-6).

Sources: U.S. Department of Commerce, Bureau of the Census. 2007. 2006 Annual Survey of Manufactures. Obtained through American Fact Finder Database <http://factfinder.census.gov/home/saff/main.html?_lang=en>.

U.S. Department of Commerce, Bureau of the Census. 2006. *2005 Annual Survey of Manufacture*s. M05(AS)-1. Washington, DC: Government Printing Office. Available at <http://www.census.gov/prod/2006pubs/am0531gs1.pdf>. As obtained on October 23, 2007.

U.S. Department of Commerce, Bureau of the Census. 2003a. *2001 Annual Survey of Manufacture*s. M01(AS)-1. Washington, DC: Government Printing Office. Available at <http://www.census.gov/prod/2003pubs/m01as-1.pdf>. As obtained on October 23, 2006.

U.S. Department of Commerce, Bureau of the Census. 2001. *1999 Annual Survey of Manufacture*s. M99(AS)-1 (RV). Washington, DC: Government Printing Office. Available at <http://www.census.gov/prod/2001pubs/m99-as1.pdf>. As obtained on October 23, 2006.

U.S. Department of Commerce, Bureau of the Census. 1998. *1996 Annual Survey of Manufacture*s. M96(AS)-1 (RV). Washington, DC: Government Printing Office. Available at <http://www.census.gov/prod/3/98pubs/m96-as1.pdf>. As obtained on October 23, 2006.

U.S. Department of Commerce, Bureau of the Census. 1997. *1995 Annual Survey of Manufacture*s. M95(AS)-1. Washington, DC: Government Printing Office. Available at <http://www.census.gov/prod/2/manmin/asm/m95as1.pdf>. As obtained on October 23, 2006.

U.S. Census Bureau, American FactFinder; "Sector 31: Annual Survey of Manufactures: General Statistics: Statistics for Industry Groups and Industries: 2009 and 2008 " Release Date: 12/3/10; (Data accessed on 10/10/11). [Source for 2008 and 2009 numbers] http://factfinder.census.gov/servlet/IBQTable?_bm=y&-NAICSASM=324110&-ds_name=AM0931GS101&-ib_type=NAICSASM&-_industry=324110&-_lang=en

U.S. Census Bureau, American FactFinder; "Sector 31: Manufacturing: Industry Series: Detailed Statistics by Industry for the United States: 2007" Release Date 10/30/09; (Data accessed on 10/11/11). [Source for 2007 numbers] http://factfinder.census.gov/servlet/IBQTable?_bm=y&-geo_id=01000US&-ds_name=EC0731I1&-NAICS2007=324110&-_lang=en

Table 2-4 Costs of Materials Used in Petroleum Refining Industry

Material	2007 Delivered Cost (10^3)	2007 Percentage of Material Costs	2002 Delivered Cost (10^3)	2002 Percentage of Material Costs
Petroleum Refineries NAICS 324110				
Total materials	440,165,193	100.00%	157,415,200	100.00%
Domestic crude petroleum, including lease condensate	133,567,383	30.3%	63,157,497	40.1%
Foreign crude petroleum, including lease condensate	219,780,279	49.9%	69,102,574	43.9%
Foreign unfinished oils (received from foreign countries for further processing)	D		2,297,967	1.5%
Ethane (C2) (80% purity or more)	—		D	
Propane (C3) (80% purity or more)	—		118,257	0.1%
Butane (C4) (80% purity or more)	7,253,910	1.7%	1,925,738	1.2%
Gas mixtures (C2, C3, C4)	—		1,843,708	1.2%
Isopentane and natural gasoline	5,117,182	1.2%	810,530	0.5%
Other natural gas liquids, including plant condensate	3,356,718	0.8%	455,442	0.3%
Toluene and xylene (100% basis)	1,801,972	0.4%	159,563	0.1%
Additives (including antioxidants, antiknock compounds, and inhibitors)	D		40,842	0.0%
Other additives (including soaps and detergents)	—		709	0.0%
Animal and vegetable oils	—		D	
Chemical catalytic preparations	D		D	
Fats and oils, all types, purchased	87,038	0.0%	—	—
Sodium hydroxide (caustic soda) (100% NaOH)	209,918	0.1%	129,324	0.1%
Sulfuric acid, excluding spent (100% H_2SO_4)	67,458	0.0%	189,912	0.1%
Metal containers	D		9,450	0.0%
Plastics containers	D		D	
Paper and paperboard containers	1,819	0.0%	D	
Cost of materials received from petroleum refineries and lube manufacturers	20,951,741	4.8%	8,980,758	5.7%
All other materials and components, parts, containers, and supplies	24,839,320	5.6%	5,722,580	3.6%
Materials, ingredients, containers, and supplies	4,745,614	1.1%	576,175	0.4%

Sources: U.S. Department of Commerce, Bureau of the Census. 2004. *2002 Economic Census, Industry Series—Shipbuilding and Repair*. Washington, DC: Government Printing Office. Available at <http://www.census.gov/prod/ec02/ec0231i324110.pdf>. As obtained on October 23, 2006.

U.S. Census Bureau, American FactFinder; "Sector 31: Manufacturing: Industry Series: Materials Consumed by Kind for the United States: 2007" Release Date 10/30/09; (Data accessed on 10/11/11). [Source for 2007 numbers] <http://factfinder.census.gov/servlet/IBQTable?_bm=y&-ds_name=EC0731I3&-NAICS2007=324110&-ib_type=NAICS2007&-geo_id=&-_industry=324110&-_lang=en&-fds_name=EC0700A1>

2.3 The Demand Side

Estimating the economic impact the regulation will have on the petroleum refining industry also requires characterizing various aspects of the demand for finished petroleum products. This section describes the characteristics of finished petroleum products, their uses and consumers, and possible substitutes.

2.3.1 Product Characteristics

Petroleum refining firms produce a variety of different products. The characteristics these products possess largely depend on their intended use. For example, the gasoline fueling our automobiles has different characteristics than the oil lubricating the car's engine. However, as discussed in Section 2.1.4, finished petroleum products can be categorized into three broad groups based on their intended uses (EIA, 1999a):

- **fuels**—petroleum products that are capable of releasing energy such as motor gasoline
- **nonfuel products**—petroleum products that are not used for powering machines or equipment such as solvents and lubricating oils
- **petrochemical feedstocks**—petroleum products that are used as a raw material in the production of plastics, synthetic rubber, and other goods

A list of selected products from each of these groups is presented in Table 2-5 along with a description of each product's characteristics and primary uses.

2.3.2 Uses and Consumers

Finished petroleum products are rarely consumed as final goods. Instead, they are used as primary inputs in the creation of a vast number of other goods and services. For example, goods created from petroleum products include fertilizers, pesticides, paints, thinners, cleaning fluids, refrigerants, and synthetic fibers (EPA, 1995). Similarly, fuels made from petroleum are used to run vehicles and industrial machinery and generate heat and electrical power. As a result, the demand for many finished petroleum products is derived from the demand for the goods and services they are used to create.

The principal end users of petroleum products can be separated into five sectors:

- Residential sector—private homes and residences
- Industrial sector—manufacturing, construction, mining, agricultural, and forestry establishments
- Transportation sector—private and public vehicles that move people and commodities such as automobiles, ships, and aircraft

- Commercial sector—nonmanufacturing or nontransportation business establishments such as hotels, restaurants, retail stores, religious and nonprofit organizations, as well federal, state, and local government institutions
- Electric utility sector—privately and publicly owned establishments that generate, transmit, distribute, or sell electricity (primarily) to the public; nonutility power producers are not included in this sector

Table 2-5 Major Refinery Products

Product	Description
	Fuels
Gasoline	A blend of refined hydrocarbons, motor gasoline ranks first in usage among petroleum products. It is primarily used to fuel automobiles and lightweight trucks as well as boats, recreational vehicles, lawn mowers, and other equipment. Other forms of gasoline include Aviation gasoline, which is used to power small planes.
Kerosene	Kerosene is a refined middle-distillate petroleum product that finds considerable use as a jet fuel. Kerosene is also used in water heaters, as a cooking fuel, and in lamps.
Liquefied petroleum gas (LPG)	LPG consists principally of propane (C_3H_8) and butane (C_4H_{10}). It is primarily used as a fuel in domestic heating, cooking, and farming operations.
Distillate fuel oil	Distillate fuel oil includes diesel oil, heating oils, and industrial oils. It is used to power diesel engines in buses, trucks, trains, automobiles, as well as other machinery.
Residual fuels	Residual fuels are the fuels distilled from the heavier oils that remain after atmospheric distillation; they find their primary use generating electricity in electric utilities. However, residual fuels can also be used as fuel for ships, industrial boiler fuel, and commercial heating fuel.
Petroleum coke	Coke is a high carbon residue that is the final product of thermal decomposition in the condensation process in cracking. Coke can be used as a low-ash solid fuel for power plants.
	Finished Nonfuel Products
Coke	In addition to use as a fuel, petroleum coke can be used a raw material for many carbon and graphite products such as furnace electrodes and liners.
Asphalt	Asphalt, used for roads and roofing materials, must be inert to most chemicals and weather conditions.
Lubricants	Lubricants are the result of a special refining process that produce lubricating oil base stocks, which are mixed with various additives. Petroleum lubricating products include spindle oil, cylinder oil, motor oil, and industrial greases.
Solvents	A solvent is a fluid that dissolves a solid, liquid, or gas into a solution. Petroleum based solvents, such as Benzyme, are used to manufacture detergent and synthetic fibers. Other solvents include toluene and xylene.
	Feedstock
Ethylene	Ethylene is the simplest alkene and has the chemical formula C_2H_4. It is the most produced organic compound in the world and it is used in the production of many products. For example, one of ethylene's derivatives is ethylene oxide, which is a primary raw material in the production of detergents.
Propylene	Propylene is an organic compound with the chemical formula C_3H_6. It is primarily used the production of polypropylene, which is used in the production of food packaging, ropes, and textiles.

Sources: U.S. Department of Labor, Occupational Safety and Health Administration (OSHA). 2003. OSHA Technical Manual, Section IV: Chapter 2, Petroleum Refining Processes. TED 01-00-015. Washington, DC: U.S. DOL. Available at <http://www.osha.gov/dts/osta/otm/otm_iv/otm_iv_2.html>. As obtained on October 23, 2006.

U.S. Department of Energy, Energy Information Administration (EIA). 1999.

Of these end users, the transportation sector consumes the largest share of petroleum products, accounting for 67% of total consumption in 2005 (EIA, 2006a). In fact, petroleum products like motor gasoline, distillate fuel, and jet fuel provide virtually all of the energy consumed in the transportation sector (EIA, 1999a).

Of the three petroleum product categories, end-users primarily consume fuel. Fuel products account for 9 out of 10 barrels of petroleum used in the United States (EIA, 1999a). In 2005, motor gasoline alone accounted for 49% of demand for finished petroleum products (EIA, 2006a).

2.3.3 Substitution Possibilities in Consumption

A major influence on the demand for finished petroleum products is the availability of substitutes. In some sectors, like the transportation sector, it is currently difficult to switch quickly from one fuel to another without costly and irreversible equipment changes, but other sectors can switch relatively quickly and easily (EIA, 1999a).

For example, equipment at large manufacturing plants often can use either residual fuel oil or natural gas. Often coal and natural gas can be easily substituted for residual fuel oil at electricity utilities. As a result, we would expect demand in these industries to be more sensitive to price (in the short run) than in others (EIA, 1999a).

However, over time, demand for petroleum products could become more elastic. For example, automobile users could purchase more fuel-efficient vehicles or relocate to areas that would allow them to make fewer trips. Technological advances could also create new products that compete with petroleum products that currently have no substitutes. An example of such a technological advance would be the invention of ethanol (an alcohol produced from biomass), which can substitute for gasoline in spark-ignition motor vehicles (EIA, 1999a).

2.4 Industry Organization

This section examines the organization of the U.S. petroleum refining industry, including market structure, firm characteristics, plant location, and capacity utilization. Understanding the industry's organization helps determine how it will be affected by new emissions standards.

2.4.1 Market Structure

Market structure characterizes the level and type of competition among petroleum refining companies and determines their power to influence market prices for their products. For example, if an industry is perfectly competitive, then individual producers cannot raise their

prices above the marginal cost of production without losing market share to their competitors. Understanding pricing behavior in the petroleum refining industry is crucial for performing subsequent EIAs.

According to basic microeconomic theory, perfectly competitive industries are characterized by unrestricted entry and exit of firms, large numbers of firms, and undifferentiated (homogenous) products being sold. Conversely, imperfectly competitive industries or markets are characterized by barriers to entry and exit, a smaller number of firms, and differentiated products (resulting from either differences in product attributes or brand name recognition of products). This section considers whether the petroleum refining industry is competitive, based on these three factors.

2.4.1.1 Barriers to Entry

Firms wanting to enter the petroleum refining industry may face at least two major barriers to entry. First, according to a 2004 Federal Trade Commission staff study, there are significant economies of scale in petroleum refinery operations. This means that costs per unit fall as a refinery produces more finished petroleum products. As a result, new firms that must produce at relatively low levels will face higher average costs than firms that are established and produce at higher levels, which will make it more difficult for these new firms to compete (Nicholson, 2005). This is known as a technical barrier to entry.

Second, legal barriers could also make it difficult for new firms to enter the petroleum refining industry. The most common example of a legal barrier to entry is patents—intellectual property rights, granted by the government, that give exclusive monopoly to an inventor over his invention for a limited time period. In the petroleum refining industry, firms rely heavily on process patents to appropriate returns from their innovations. As a result, firms seeking to enter the petroleum refining industry must develop processes that respect the novelty requirements of these patents, which could potentially make entry more difficult for new firms (Langinier, 2004). A second example of a legal barrier would be environmental regulations that apply only to new entrants or new pollution sources. Such regulations would raise the operating costs of new firms without affecting the operating costs of existing ones. As a result, new firms may be less competitive.

Although neither of these barriers is impossible for new entrants to overcome, they can make it more difficult for new firms to enter the market for manufactured petroleum products. As a result, existing petroleum refiners could potentially raise their prices above competitive levels with less worry about new firms entering the market to compete away their customers with lower

prices. It was not possible during this analysis to quantify how significant these barriers would be for new entrants or what effect they would have on market prices. However, existing firms would still face competition from each other. In an unconcentrated industry, competition among existing firms would work to keep prices at competitive levels.

2.4.1.2 Measures of Industry Concentration

Economists often use a variety of measures to assess the concentration of a given industry. Common measures include four-firm concentration ratios (CR4), eight-firm concentration ratios (CR8), and Herfindahl-Hirschmann indexes (HHI). The CR4s and CR8s measure the percentage of sales accounted for by the top four and eight firms in the industry. The HHIs are the sums of the squared market shares of firms in the industry. These measures of industry concentrated are reported for the petroleum refining industry (NAICS 324110) in Table 2-6 for selected years between 1985 and 2007.

Between 1990 and 2000, the HHI rose from 437 to 611, which indicates an increase in market concentration over time. This increase is partially due to merger activity during this time period. Between 1990 and 2000, over 2,600 mergers occurred across the petroleum industry; 13% of these mergers occurred in the industry's refining and marketing segments (GAO, 2007). From 2000 to 2007 the HHI rose again.

Unfortunately, there is no objective criterion for determining market structure based on the values of these concentration ratios. However, accepted criteria have been established for determining market structure based on the HHIs for use in horizontal merger analyses (U.S. Department of Justice and the Federal Trade Commission, 1992). According to these criteria, industries with HHIs below 1,000 are considered unconcentrated (i.e., more competitive); industries with HHIs between 1,000 and 1,800 are considered moderately concentrated (i.e., moderately competitive); and industries with higher HHIs are considered heavily concentrated. Based on this criterion, the petroleum refining industry continues to be unconcentrated even in recent years.

A more rigorous examination of market concentration was conducted in a 2004 Federal Trade Commission (FTC) staff study. This study explicitly accounted for the fact that a refinery in one geographic region may not exert competitive pressure on a refinery in another region if transportation costs are high. This was done by comparing HHIs across Petroleum Administration for Defense Districts (PADDs). PADDs separate the United States into five geographic regions or districts. They were initially created during World War II to help manage

the allocation of fuels during wartime. However, they have remained in use as a convenient way of organizing petroleum market information (FTC, 2004).

Table 2-6 Market Concentration Measures of the Petroleum Refining Industry: 1985 to 2007

Measure	1985	1990	1996	2000	2001	2002	2003	2007
Herfindahl-Hirschmann Index (HHI)	493	437	412	611	686	743	728	807
Four-firm concentration ratio (CR4)	34.4	31.4	27.3	40.2	42.5	45.4	44.4	47.5
Eight-firm concentration ratio (CR8)	54.6	52.2	48.4	61.6	67.2	70.0	69.4	73.1

Sources: Federal Trade Commission (FTC). 2004. "The Petroleum Industry: Mergers, Structural Change, and Antitrust Enforcement." Available at <http://www.ftc.gov/opa/2004/08/oilmergersrpt.shtm>. As obtained on February 6, 2007.

U.S. Census Bureau, American FactFinder; "Sector 31: Manufacturing: Subject Series: Concentration Ratios: Share of Value of Shipments Accounted for by the 4, 8, 20, and 50 Largest Companies for Industries: 2007 " Release Date 1/7/2011; (Data accessed on 10/12/11) [Source for 2007 numbers]<http://factfinder.census.gov/servlet/IBQTable?_bm=y&-ds_name=EC0731SR12&-NAICS2007=324110&-ib_type=NAICS2007&-NAICS2007sector=*6&-industrySel=324110&-geo_id=&-_industry=324110&-_lang=en>

This study concluded that these geographic markets were not highly concentrated. PADDs I, II, and III (East Coast, Midwest, and Gulf Coast) were sufficiently connected that they exerted a competitive influence on each other. The HHI for these combined regions was 789 in 2003, indicating a low concentration level. Concentration in PADD IV (Rocky Mountains) was also low in 2003, with an HHI of 944. PADD V gradually grew more concentrated in the 1990s after a series of significant refinery mergers. By 2003, the region's HHI was 1,246, indicating a growth to a moderate level of concentration (FTC, 2004).

2.4.1.3 Product Differentiation

Another way firms can influence market prices for their product is through product differentiation. By differentiating one's product and using marketing to establish brand loyalty, manufacturers can raise their prices above marginal cost without losing market share to their competitors.

While we saw in Section 3.3 that there are a wide variety of petroleum products with many different uses, individual petroleum products are by nature quite homogenous. For example, there is little difference between premium motor gasoline produced at different refineries (Mathtech, 1997). As a result, the role of product differentiation is probably quite small for many finished petroleum products. However, there are examples of relatively small

refining businesses producing specialty products for small niche markets. As a result, there may be some instances where product differentiation is important for price determination.

2.4.1.4 Competition among Firms in the Petroleum Refining Industry

Overall, the petroleum industry is characterized as producing largely generic products for sale in relatively unconcentrated markets. Although it is not possible to quantify how much barriers to entry and other factors will affect competition among firms, it seems unlikely that individual petroleum refiners would be able to significantly influence market prices given the current structure of the market.

2.4.2 Characteristics of U.S. Petroleum Refineries and Petroleum Refining Companies

A petroleum refinery is a facility where labor and capital are used to convert material inputs (such as crude oil and other materials) into finished petroleum products. Companies that own these facilities are legal business entities that conduct transactions and make decisions that affect the facility. The terms "facility," "establishment," and "refinery" are synonymous in this report and refer to the physical location where products are manufactured. Likewise, the terms "company" and "firm" are used interchangeably to refer to the legal business entity that owns one or more facilities. This section presents information on refineries, such as their location and capacity utilization, as well as financial data for the companies that own these refineries.

2.4.2.1 Geographic Distribution of U.S. Petroleum Refineries

There are approximately 148 petroleum refineries operating in the United States, spread across 32 states. The number of petroleum refineries located in each of these states is listed in Table 2-7. This table illustrates that a significant portion of petroleum refineries are located along the Gulf of Mexico region. The leading petroleum refining states are Texas, Louisiana, and California.

2.4.2.2 Capacity Utilization

Capacity utilization indicates how well current refineries meet demand. One measure of capacity utilization is capacity utilization rates. A capacity utilization rate is the ratio of actual production volumes to full-capacity production volumes. For example, if an industry is producing as much output as possible without adding new floor space for equipment, the capacity utilization rate would be 100 percent. On the other hand, if under the same constraints the industry were only producing 75 percent of its maximum possible output, the capacity utilization rate would be 75 percent. On an industry-basis, capacity utilization is highly variable from year to year depending on economic conditions. It is also variable on a company-by-

company basis depending not only on economic conditions, but also on a company's strategic position in its particular industry. While some plants may have idle production lines or empty floor space, others need additional space or capacity.

Table 2-8 lists the capacity utilization rates for petroleum refineries from 2000 to 2010. It is interesting to note the declines in capacity utilization from 2007 to 2008 and again from 2008 to 2009. These declines seem counter intuitive because there does not appear to be evidence that demand for petroleum products is dropping. To understand this better, it is important to realize that the capacity utilization ratio in the petroleum industry represents the utilization of the atmospheric crude oil distillation units. This ratio is calculated for the petroleum industry by dividing the gross input to atmospheric crude oil distillation units (all inputs involved in atmospheric crude oil distillation, such as crude oil) by the industry's operational capacity.

Table 2-7 Number of Petroleum Refineries, by State

State	Number of Petroleum Refineries
Alabama	3
Alaska	6
Arkansas	2
California	20
Colorado	2
Delaware	1
Georgia	1
Hawaii	2
Illinois	4
Indiana	2
Kansas	3
Kentucky	2
Louisiana	19
Michigan	1
Minnesota	2
Mississippi	3
Montana	4
Nevada	1
New Jersey	5
New Mexico	3
North Dakota	1
Ohio	4
Oklahoma	6
Pennsylvania	5
Tennessee	1
Texas	26
Utah	5
Virginia	1
Washington	5
West Virginia	1
Wisconsin	1
Wyoming	6
Total	148

Source: U.S. Energy Information Administration (EIA), Form EIA-820, "Annual Refinery Report. Table 1. Number and Capacity of Operable Petroleum Refineries by PAD District and State as of January 1, 2011" Release Date: June 24, 2011; (Data accessed on 10/12/11). [Source for 2011 numbers.] http://www.eia.gov/petroleum/refinerycapacity/

Table 2-8 Full Production Capacity Utilization Rates for Petroleum Refineries

Year	Petroleum Refineries Capacity Utilization Rates (NAICS 324110)	Gross Input to Atmospheric Crude Oil Distillation Units (1,000s of barrels per day)	Operational Capacity (1,000s of barrels per day)
2000	92.6	15,299	16,525
2001	92.6	15,352	16,582
2002	90.7	15,180	16,744
2003	92.6	15,508	16,748
2004	93.0	15,783	16,974
2005	90.6	15,578	17,196
2006	89.7	15,602	17,385
2007	88.5	15,450	17,450
2008	85.3	15,027	17,607
2009	82.9	14,659	17,678
2010	86.4	15,177	17,575

Sources: U.S. Department of Energy, Energy Information Administration (EIA). 2007a. "Refinery Utilization and Capacity." Available at <http://tonto.eia.doe.gov/dnav/pet/ pet_pnp_unc_dcu_nus_m.htm>. As obtained on January, 2007.

U.S. Energy Information Administration (EIA), "Refinery Utilization and Capacity." Available at http://www.eia.gov/dnav/pet/pet_pnp_unc_dcu_nus_a.htm; Release date: 7/28/11; (Data accessed on 10/11/11). [Source for 2007-2010 numbers]

From 2007 to 2008 operational capacity increased from 17,450,000 barrels per calendar day to 17,607,000 barrels per calendar day at the same time gross inputs fell from 15,450,000 barrels per calendar day to 15,027,000 barrels per calendar day resulting in a 3.6 percent decrease in utilization. Similarly, from 2008 to 2009 operational capacity increased from 17,607,000 barrels per calendar day to 17,678,000 barrels per calendar day at the same time gross inputs fell from 15,027,000 barrels per calendar day to 14,659,000 barrels per calendar day resulting in a 2.8 percent decrease in utilization.

2.4.2.3 Characteristics of Small Businesses Owning U.S. Petroleum Refineries

Under Small Business Administration (SBA) regulations, a small refiner is defined as a refinery with no more than 1,500 employees.[3] For this analysis we applied the small refiner definition of a refinery with no more than 1,500 employees. For additional information on the Agency's application of the definition for small refiner, see the June 24, 2008 Federal Register Notice for 40 CFR Part 60, Standards of Performance for Petroleum Refineries (Volume 73, Number 122, page 35858).

As of January 2011, there were 148 petroleum refineries operating in the continental United States and US territories with a cumulative capacity of processing over 17 million barrels of crude per calendar day (EIA, 2011a). We identified 64 parent companies owning refineries in

[3] See Table in 13 CFR 121.201, NAICS code 324110.

the United States and were able to collect employment and sales data for 61 (95%) of them. We were not able to collect employment and sales data for Ten By Inc., PBF Holdings LLC, and Northern Tier Energy LLC, representing 2.36% of refining capacity.

The distribution of employment across companies is illustrated in Figure 2-6. As this figure shows, 36 companies (59% of the 61 total) employee fewer than 1,500 workers and would be considered small businesses. These firms earned an average of $1.36 billion of revenue per year, while firms employing more than 1,500 employees earned an average of $82.5 billion of revenue per year (Figure 2-7). Distributions of the number of large and small firms earning different levels of revenue are presented in Figures 2-8 and 2-9.

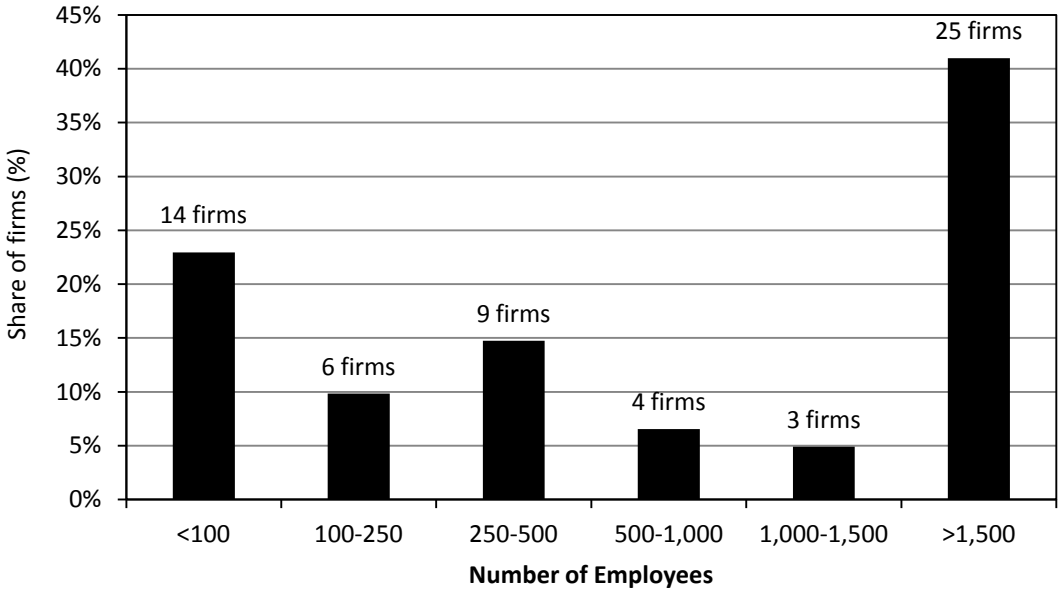

Figure 2-6 Employment Distribution of Companies Owning Petroleum Refineries (N=61)

Sources: Employment Data from Petroleum Refinery Emissions Information Collection, where available, Component 1, OMB Control No. 2060-0657.

Hoovers 2011 Online Data, accessed through University of South Carolina's Moore School of Business Library. Hoovers 2011 Online Data reflects either actual data for 2010/2011 reported by companies, estimated data for 2011, or occasionally 2009 values.

Million Dollar Database online, 2011, accessed through University of South Carolina's Moore School of Business Library. Million Dollar Online Data reflects either actual data for 2011 reported by companies or estimated data for 2011.

Ward's Business Directory of Public and Private Companies, 2011, accessed at James Branch Cabell Library (Virginia Commonwealth University). Ward's Business Directory compiles financial data from several sources such as annual reports, company websites, and phone interviews. If financial data from private companies is unavailable, Ward's staff estimates the information.

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Global Duns Market Identifiers, accessed through LexisNexis at University of Virginia's Alderman Library.

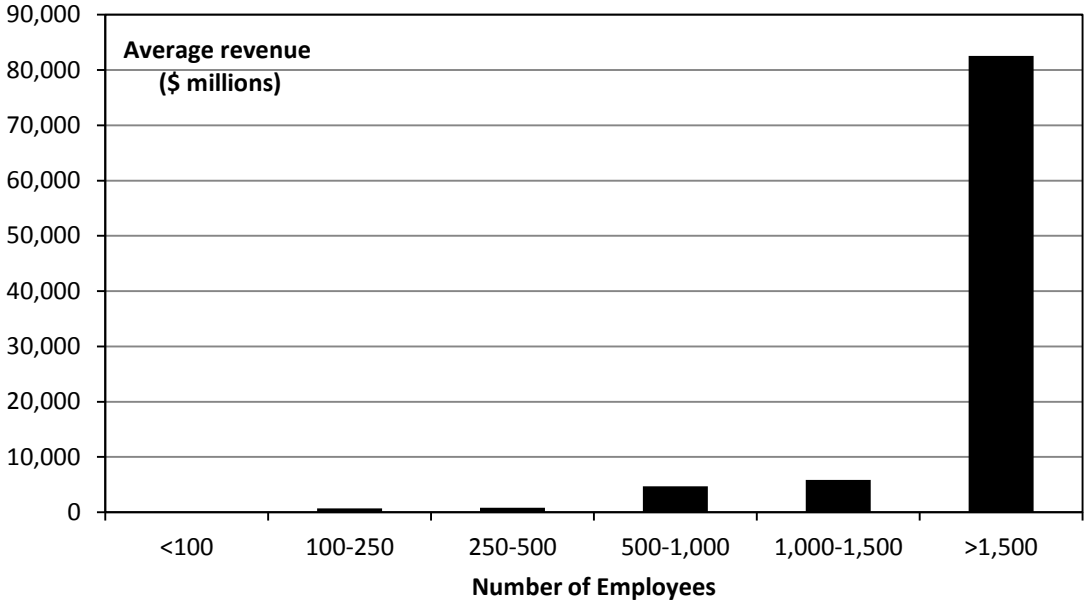

Figure 2-7 Average Revenue of Companies Owning Petroleum Refineries by Employment (N=61)

Sources: Employment Data from Petroleum Refinery Emissions Information Collection, where available, Component 1, OMB Control No. 2060-0657.

Hoovers 2011 Online Data, accessed through University of South Carolina's Moore School of Business Library. Hoovers 2011 Online Data reflects either actual data for 2010/2011 reported by companies, estimated data for 2011, or occasionally 2009 values.

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Global Duns Market Identifiers, accessed through LexisNexis at University of Virginia's Alderman Library.

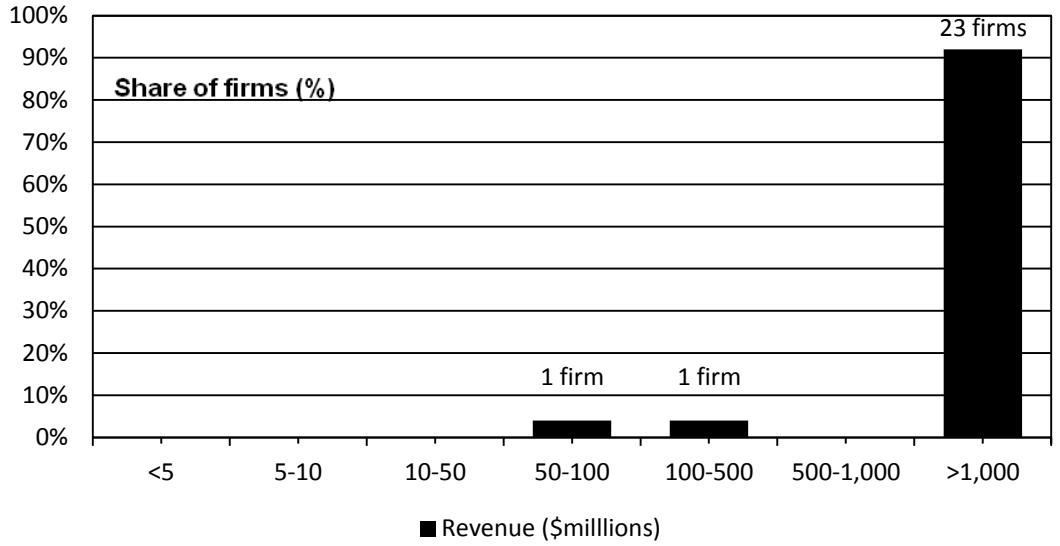

Figure 2-8 Revenue Distribution of Large Companies Owning Petroleum Refineries (N=25)

Sources: Employment Data from Petroleum Refinery Emissions Information Collection, where available, Component 1, OMB Control No. 2060-0657.

Hoovers 2011 Online Data, accessed through University of South Carolina's Moore School of Business Library. Hoovers 2011 Online Data reflects either actual data for 2010/2011 reported by companies, estimated data for 2011, or occasionally 2009 values.

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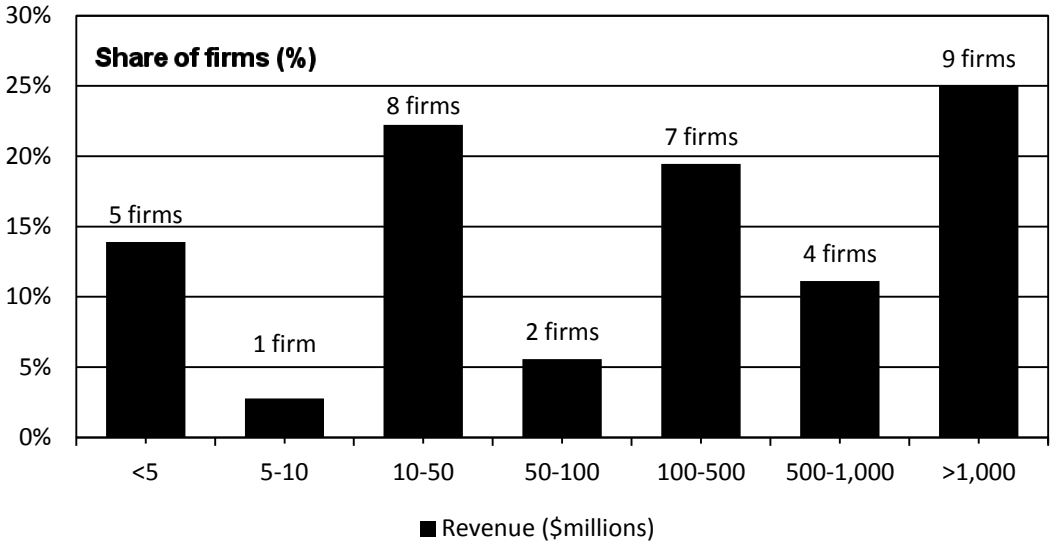

Figure 2-9 Revenue Distribution of Small Companies Owning Petroleum Refineries (N=36)

Sources: Employment Data from Petroleum Refinery Emissions Information Collection, where available, Component 1, OMB Control No. 2060-0657.

Hoovers 2011 Online Data, accessed through University of South Carolina's Moore School of Business Library. Hoovers 2011 Online Data reflects either actual data for 2010/2011 reported by companies, estimated data for 2011, or occasionally 2009 values.

Million Dollar Database online, 2011, accessed through University of South Carolina's Moore School of Business Library. Million Dollar Online Data reflects either actual data for 2011 reported by companies or estimated data for 2011.

Ward's Business Directory of Public and Private Companies, 2011, accessed at James Branch Cabell Library (Virginia Commonwealth University). Ward's Business Directory compiles financial data from several sources such as annual reports, company websites, and phone interviews. If financial data from private companies is unavailable, Ward's staff estimates the information.

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Global Duns Market Identifiers, accessed through LexisNexis at University of Virginia's Alderman Library.

Employment, crude capacity, and location information are provided in Table 2-9 for each refinery owned by a parent company employing 1,500 employees or less. Similar information can be found for all 64 companies owning petroleum refineries in Appendix A.

In Section 3.4.2.1, we discussed how petroleum refining operations are characterized by economies of scale—that the cost per unit falls as a refinery produces more finished petroleum products. This means that smaller petroleum refiners face higher per unit costs than larger refining operations because they produce fewer petroleum products. As a result, some smaller firms have sought to overcome their competitive disadvantage by locating close to product-consuming areas to lower transportation costs and serving niche product markets (FTC, 2004).

A good example of a firm locating close to prospective customers is Countrymark Cooperative, Inc., which was started in the 1930s for the express purpose of providing farmers in Indiana with a consistent supply of fuels, lubricants, and other products. A good example of a firm producing niche products is Calumet Specialty Product Partners. The firm produces both basic fuels like gasoline, diesel fuel and jet fuel and specialty products like lubricating oils, solvents, waxes, and other petroleum products. However, the firm's specialty products unit is its largest unit (Hoovers, 2011 online). Also Arabian American Development Company's South Hampton Resources facility specializes in producing high purity solvents for the plastics and foam industries.

However, recent developments are making these factors less important for success in the industry. For example, the entry of new product pipelines is eroding the locational advantage of smaller refineries (FTC, 2004). This trend can possibly be illustrated by the fact that most refineries owned by small businesses tend to be located in relatively rural areas (see Table 2-9). The median population density of counties occupied by small refineries is 103 people per square mile. This could suggest that refineries do not rely on the population surrounding them to support their refining operations.

Capacity information for the refineries owned by small businesses also suggests that fewer small businesses are focusing on developing specialty products or serving local customers as major parts of their business plan. For example, in 2006 29 small refineries had a collective crude refining capacity of 778,920 barrels per calendar day or 857,155 barrels per stream day (EIA, 2006c). Approximately 21% of this total capacity was devoted to producing specialty products or more locally focused products such as aromatics, asphalt, lubricants, and petroleum coke. The remaining 79% was used to produce gasoline, kerosene, diesel fuel, and liquefied petroleum gases. Similarly, in 2011, approximately 20% of small businesses' total capacity was dedicated to producing specialty products and 80% was dedicated to producing fuel products. As discussed in Section 3.4.1.3, fuel products tend to be quite homogenous (gasoline from one refinery is not very different from gasoline from another refinery), and they are also normally transported by pipeline.

2.5 Markets

This section provides data on the volume of petroleum products produced and consumed in the United States, the quantity of products imported and exported, and the average prices of major petroleum products. The section concludes with a discussion of future trends for the petroleum refining industry.

2.5.1 U.S. Petroleum Consumption

Figure 2-10 illustrates the amount of petroleum products supplied between 2000 and 2010 (measured in millions of barrels of oil). These data represent the approximate consumption of petroleum products because it measures the disappearance of these products from primary sources (i.e., refineries, natural gas processing plants, blending plants, pipelines, and bulk terminals).

Table 2-9 Characteristics of Small Businesses in the Petroleum Refining Industry

Parent Company	Parent Company Type	Cumulative Crude Capacity (bbl/cd)	Parent Company Employment (#)	Facility Name	Facility City	Facility State	Facility County	Facility County Population Density (2000)	Facility County Population Density (2010)
AGE Refining, Inc.	Private	14,021	124	AGE Refining Inc	San Antonio	TX	Bexar County	1,117	1,383
American Refining Group, Inc.	Private	10,000	323	American Refining Group Inc	Bradford	PA	McKean County	47	44
Arabian American Development Co	Public	0	145	South Hampton Resources Inc.	Silsbee	TX	Hardin County	54	61
BTB Refining	Private	0	37	Trigeant Ltd.	Corpus Christi	TX	Nueces County	375	406
Calcasieu Refining Company	Private	78,000	92	Calcasieu Refining Co.	Lake Charles	LA	Calcasieu Parish	171	181
Calumet Specialty Products Partners, L.P.	Public	57,000	654	Calumet Shreveport LLC	Shreveport	LA	Caddo Parish	286	290
Calumet Specialty Products Partners, L.P.	Public	13,020	654	Calumet Lubricants Co LP	Cotton Valley	LA	Caddo Parish	286	290
Calumet Specialty Products Partners, L.P.	Public	8,300	654	Calumet Lubricants Co LP	Princeton	LA	Caddo Parish	286	290
CHS, Inc.	Public	59,600	287	Cenex Harvest States	Laurel	MT	Yellowstone County	49	56
Connacher Oil and Gas, Limited	Public	10,000	170	Montana Refining Co.	Great Falls	MT	Cascade County	30	30
CVR Energy, Inc.	Public	115,700	371	Coffeyville Resources Rfg&Mktg LLC	Coffeyville	KS	Montgomery County	56	55
Countrymark Cooperative	Private	26,500	425	Countrymark Cooperative, Inc.	Mt. Vernon	IN	Posey County	66	63
Cross Oil Refining & Marketing, Inc.	Private	7,500	110	Martin Midstream Partners LP	Smackover	AR	Union County	44	40
Foreland Refining Corp.	Private	2,000	27	Foreland Refining Co.	Ely	NV	White Pine County	1	1
Frontier Oil Corp.	Private	47,000	723	Frontier Refining Inc	Cheyenne	WY	Laramie County	30	34

(continued)

Table 2-9. Characteristics of Small Businesses in the Petroleum Refining Industry (continued)

Parent Company	Parent Company Type	Cumulative Crude Capacity (bbl/cd)	Parent Company Employment (#)	Facility Name	Facility City	Facility State	Facility County	Facility County Population Density (2000)	Facility County Population Density (2010)
Frontier Oil Corp.	Private	138,000	723	Frontier El Dorado Refining Co	El Dorado	KS	Butler County	42	46
Garco Energy	Private	3,600	16	Garco Energy LLC	Douglas	WY	Converse County	3	3
Gary-Williams Energy Corporation	Private	70,000	260	Wynnewood Refining Co.	Wynnewood	OK	Garvin County	34	34
Goodway Refining, LLC	Private	4,100	17	Goodway Refining LLC	Atmore	AL	Escambia County	41	41
Gulf Atlantic Operations LLC	Private		32	Gulf Atlantic Operations LLC	Mobile Bay	AL	Mobile County	324	336
Holly Corporation	Public	25,050	1,321	Holly Refining & Marketing Co	Woods Cross	UT	Davis County	785	1,026
Holly Corporation	Public	105,000	1,321	Navajo Refining Co.	Artesia	NM	Eddy County	12	13
Holly Corporation	Public	70,300	1,321	Holly Refining & Marketing Co	Tulsa East	OK	Tulsa County	988	1,058
Holly Corporation	Public	85,000	1,321	Holly Refining & Marketing Co	Tulsa West	OK	Tulsa County	988	1,058
Hunt Refining Co.	Private	36,000	1,100	Hunt Refining Co.	Tuscaloosa	AL	Tuscaloosa County	125	147
Hunt Refining Co.	Private	11,000	1,100	Hunt Southland Refining Co	Sandersville	MS	Lamar County	79	112
Kern Oil & Refining Co.	Private	26,000	346	Kern Oil & Refining Co.	Bakersfield	CA	Kern County	81	103
Lion Oil Co.	Private	75,000	350	Lion Oil Co.	El Dorado	AR	Union County	44	40
National Cooperative Refinery Association	Public	85,500	612	National Cooperative Refinery Association	McPherson	KS	McPherson County	33	33
NuStar Energy LP	Public	70,000	1,492	Nustar Asphalt Refining LLC	Paulsboro	NJ	Gloucester	784	895
NuStar Energy LP	Public	28,000	1,492	Nustar Asphalt Refining LLC	Savannah	GA	Chatham	530	622

(continued)

Table 2-9. Characteristics of Small Businesses in the Petroleum Refining Industry (continued)

Parent Company	Parent Company Type	Cumulative Crude Capacity (bbl/cd)	Parent Company Employment (#)	Facility Name	Facility City	Facility State	Facility County	Facility County Population Density (2000)	Facility County Population Density (2010)
Pasadena Refining Systems Inc.	Private	120,000	348	Pasadena Refining Systems Inc.	Pasadena	TX	Harris County	1967	2,402
Pelican Refining Co LLC	Private	0	33	Pelican Refining Co. LLC	Lake Charles	LA	Calcasieu Parish	171	181
Petro Star Inc.	Private	19,700	400	Petro Star Inc.	North Pole	AK	Fairbanks North Star	11	13
Petro Star Inc.	Private	55,000	400	Petro Star Inc.	Valdez	AK	Valdez Cordova	0.3	0
Placid Refining	Private	57,000	207	Placid Refining Inc.	Port Allen	LA	West Baton Rouge Parish	113	124
San Joaquin Refining Co.	Private	15,000	108	San Joaquin Refining Co., Inc.	Bakersfield	CA	Kern County	81	103
Santa Maria Refining Company	Private	9,500	47	Greka Energy	Santa Maria	CA	Santa Barbara County	146	155
Silver Eagle Refining Inc.	Private	3,000	60	Silver Eagle Refining	Evanston	WY	Uinta County	10	10
Silver Eagle Refining Inc.	Private	10,250	60	Silver Eagle Refining	Woods Cross	UT	Davis County	785	1,026
Somerset Oil Inc.	Private	5,500	11	Somerset Energy Refinery LLC	Somerset	KY	Pulaski County	85	96
US Oil & Refining Co.	Private	38,800	182	US Oil & Refining Co.	Tacoma	WA	Pierce County	417	476
Ventura Refining & Transmission, LLC	Private	12,000	37	Ventura Refining & Transmission LLC	Thomas	OK	Custer County	27	28
Western Refining, Inc.	Public	122,000	636	Western Refining Company LP	El Paso	TX	El Paso County	671	791
Western Refining, Inc.	Public	66,300	636	Western Refining Yorktown Inc	Yorktown	VA	York County	533	625
Western Refining, Inc.	Public	16,800	636	Western Refining Southwest Inc	Bloomfield	NM	San Juan County	21	24
Western Refining, Inc.	Public	21,100	636	Western Refining Southwest Inc	Gallup	NM	McKinley County	14	13

(continued)

Table 2-9. Characteristics of Small Businesses in the Petroleum Refining Industry (continued)

Parent Company	Parent Company Type	Cumulative Crude Capacity (bbl/cd)	Parent Company Employment (#)	Facility Name	Facility City	Facility State	Facility County	Facility County Population Density (2000)	Facility County Population Density (2010)
World Oil Marketing Co.	Private	8,500	65	Lunday-Thagard Co.	South Gate	CA	Los Angeles County	2,344	2,420
Wyoming Refining Co.	Private	14,000	96	Wyoming Refining Co	New Castle	WY	Weston County	3	3
Total		1,875,641	11,264						103

Sources: U.S. Census Bureau, American Fact Finder, "2010 Census Summary File 1 Population, Housing Units, Area & Density: 2010- County – Census Tract 100% Data 2010 Census" (Data accessed on 10/21/2011); http://factfinder2.census.gov/faces/tableservices/jsf/pages/productview.xhtml?ftp=table

Hoovers 2011 Online Data, accessed through University of South Carolina's Moore School of Business Library. Hoovers 2011 Online Data reflects either actual data for 2010/2011 reported by companies, estimated data for 2011, or occasionally 2009 values.

Million Dollar Database online, 2011, accessed through University of South Carolina's Moore School of Business Library. Million Dollar Online Data reflects either actual data for 2011 reported by companies or estimated data for 2011.

Ward's Business Directory of Public and Private Companies, 2011, accessed at James Branch Cabell Library (Virginia Commonwealth University). Ward's Business Directory compiles financial data from several sources such as annual reports, company websites, and phone interviews. If financial data from private companies is unavailable, Ward's staff estimates the information.

Copyright 2011 Harte-Hanks Market Intelligence, Inc., All Rights Reserved. CI Technology Database, September 2011.

Reference USA, accessed thru Jefferson Madison Regional Library, Charlottesville, Virginia.

Copyright 2011 Experian Information Solutions, Inc., Experian Business Reports accessed through LexisNexis at James Branch Cabell Library (Virginia Commonwealth University). Experian Business Reports reflects the most recent data reported by a company, which may be 2010 or 2011.

Global Duns Market Identifiers, accessed through LexisNexis at University of Virginia's Alderman Library.

Employment Data from Petroleum Refinery Emissions Information Collection, where available, Component 1, OMB Control No. 2060-0657.

Energy Information Administration (EIA), Form EIA 820, "Annual Refinery Report," Table 3. Capacity of Operable Petroleum Refineries by State and Individual Refinery as of January 1, 2011 <http://www.eia.gov/petroleum/refinerycapacity/>

Between 2000 and 2004, U.S. consumption of petroleum products increased by 5%. Consumption leveled off by 2007 and dropped by 9% between 2007 and 2009 (Figure 2-10). This reduced growth was primarily the result of less jet fuel, residual fuel, distillate fuel, and other products being consumed in recent years. Consumption of all petroleum products, except for motor gasoline, increased between 2009 and 2010, but the total consumption of petroleum products did not reach 2000-2004 levels. The cumulative decrease in consumption over the 11 year period is 3% (Table 2-10).

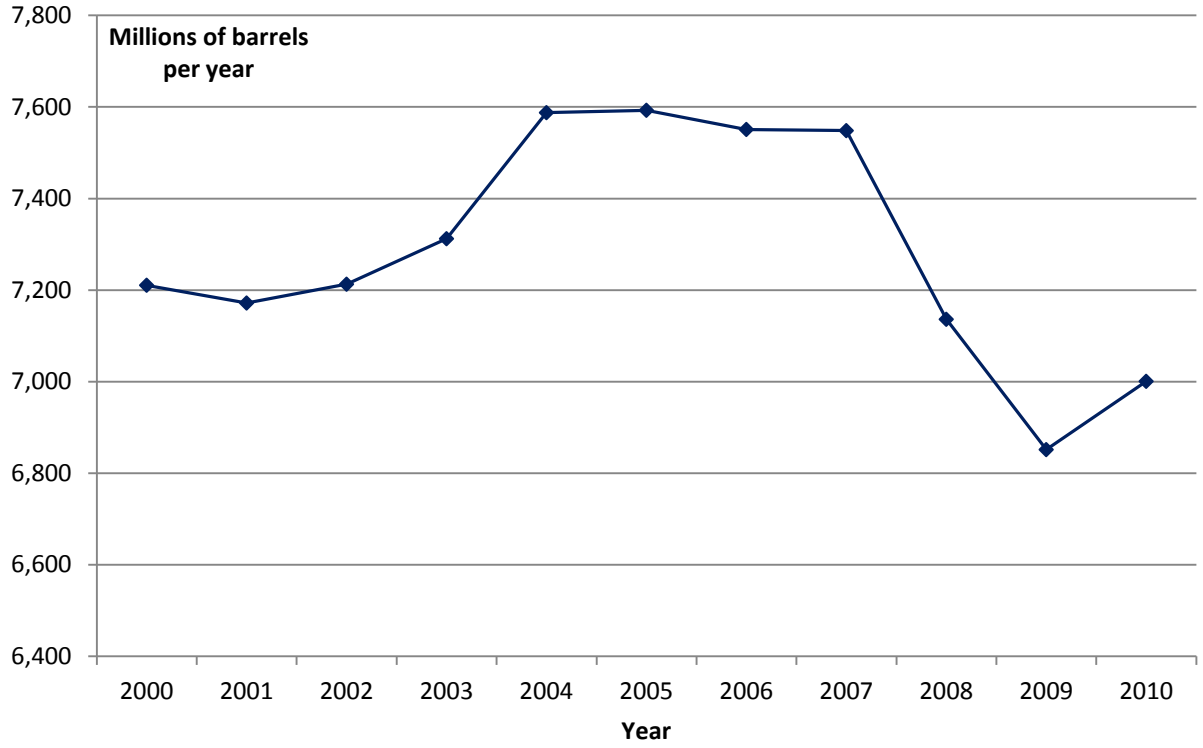

Figure 2-10 Total Petroleum Products Supplied (millions of barrels per year)

Sources: U.S. Department of Energy. 2011 Energy Information Administration (EIA). 1996–2011. "Petroleum Supply Annuals, Volume 1." (Data accessed on February 23, 2012) [Source for 2000–2010 numbers.] < http://www.eia.gov/dnav/pet/pet_cons_psup_dc_nus_mbbl_a.htm >.

Table 2-10 Total Petroleum Products Supplied (millions of barrels per year)

Year	Motor Gasoline	Jet Fuel	Distillate Fuel Oil	Residual Fuel Oil	Liquefied Petroleum Gases	Other Products	Total
2000	3,101	631	1,362	333	816	967	7,211
2001	3,143	604	1,404	296	746	978	7,172
2002	3,229	591	1,378	255	789	969	7,213
2003	3,261	576	1,433	282	757	1,003	7,312
2004	3,333	597	1,485	316	780	1,076	7,588
2005	3,343	613	1,503	336	741	1,057	7,593
2006	3,377	596	1,522	251	749	1,055	7,551
2007	3,389	592	1,532	264	761	1,011	7,548
2008	3,290	563	1,444	228	715	896	7,136
2009	3,284	509	1,325	187	749	799	6,852
2010	3,282	523	1,387	195	793	820	7,001

Sources: Annuals, Volume 1." Available at <http://www.eia.doe.gov/oil_gas/petroleum/data_publications/petroleum_supply_annual/psa_volume1/psa_volume1.html>. As obtained on October 31, 2007.

U.S. Department of Energy. 2011 Energy Information Administration (EIA). 1996–2011. "Petroleum Supply Annuals, Volume 1." (Data accessed on October 11, 2011) [Source for 2007–2010 numbers.] <http://www.eia.gov/dnav/pet/pet_sum_snd_d_nus_mbbl_a_cur.htm>.

2.5.2 U.S. Petroleum Production

Table 2-11 reports the number of barrels of major petroleum products produced in the United States between 2000 and 2010. U.S. production of petroleum products at refineries and blenders grew steadily, resulting in a 7% cumulative increase for the period. However, in 2005 and 2009 production declined by slightly.

Table 2-11 U.S. Refinery and Blender Net Production (millions of barrels per year)

Year	Motor Gasoline	Jet Fuel	Distillate Fuel Oil	Residual Fuel Oil	Liquefied Petroleum Gases	Other Products	Total
2000	2,910	588	1,310	255	258	990	6,311
2001	2,928	558	1,349	263	243	968	6,309
2002	2,987	553	1,311	219	245	990	6,305
2003	2,991	543	1,353	241	240	1,014	6,383
2004	3,025	566	1,396	240	236	1,057	6,520
2005	3,036	564	1,443	229	209	1,015	6,497
2006	3,053	541	1,475	232	229	1,032	6,561
2007	3,051	528	1,509	246	239	464	6,568
2008	3,129	546	1,572	227	230	950	6,641
2009	3,207	510	1,478	218	227	1,418	6,527
2010	3,306	517	1,542	213	240	1,747	6,735

Sources: U.S. Department of Energy, Energy Information Administration (EIA). 1996–2007. "Petroleum Supply Annuals, Volume 1." Available at <http://www.eia.doe.gov/oil_gas/petroleum/data_publications/petroleum_supply_annual/psa_volume1/psa_volume1.html>. As obtained on October 31, 2007.

U.S. Department of Energy. 2011 Energy Information Administration (EIA). 1996–2011. "Petroleum Supply Annuals, Volume 1." (Data accessed on October 7, 2011) [Source for 2007–2010 numbers.] <http://www.eia.gov/dnav/pet/pet_pnp_refp_dc_nus_mbbl_a.htm>.

The 2005 decline in production (0.35%) was possibly the result of damage inflicted by two hurricanes (Hurricane Katrina and Hurricane Rita) on the U.S. Gulf Coast—the location of many U.S. petroleum refineries (Section 3.4.2). According to the American Petroleum Institute, approximately 30% of the U.S. refining industry was shut down as a result of the damage (API, 2006). The 2009 decline in production (1.72%) was probably the result of the global economic crisis. Additional production data are presented in Table 2-12, which reports the value of shipments of products produced by the petroleum refining industry between 1997 and 2009.

2.5.3 International Trade

International trade trends are shown in Tables 2-13 and 2-14. Between 1995 and 2006, imports and exports of petroleum products increased by 123% and 51% respectively. Between 1995 and 2006, while imports of most major petroleum products grew at approximately the same rate, the growth of petroleum product exports was driven largely by residual fuel oil and other petroleum products. More recently, between 2008 and 2010 exports of petroleum products such as motor gasoline, jet fuel, distillate fuel oil and liquefied petroleum gases have also increased.

Since 2006, industry import and export trends have diverged significantly. Between 2006 and 2010 imports declined by 28%, returning close to 2001 levels. In 2010, U.S. net imports were 98 million barrels, accounting for 10% of the country's imports and around 1% of total petroleum products consumed in that year. Exports grew at an average annual rate of 12% and in 2010 were 2.4 times the level of exports in 2001.

In 2011, U.S. net imports of crude oil, based on a four-week average, ranged from 8,138 to 9,474 thousand barrels per day. And while 2011 started out with the U.S. as a net importer of total petroleum products, from July 2011 through December 2011 the U.S. became a net exporter of total petroleum products. From July to December 2011, based on a four-week average, the U.S. exported an average of 405,000 barrels per day with a maximum of 809,000 barrels per day of total petroleum products (EIA 2012).[4]

[4] Data for 2011 located on the Energy Information Administration's website at http://www.eia.gov/dnav/pet/pet_move_wkly_dc_NUS-Z00_mbblpd_4.htm.

Table 2-12 Value of Product Shipments of the Petroleum Refining Industry

Year	Millions of $Reported	Millions of $2005
1997	152,756	180,671
1998	114,439	136,746
1999	140,084	164,651
2000	210,187	237,425
2001	195,898	219,476
2002	186,761	210,647
2003	216,764	238,425
2004	290,280	306,328
2005	419,063	419,063
2006	489,051	470,037
2007	551,997	510,996
2008	682,756	585,664
2009	436,974	394,348

Note: Numbers were adjusted for inflation using producer price index industry data for Total Manufacturing Industries (Table 2-16).

Sources: U.S. Department of Commerce, Bureau of the Census. 2007. 2006 Annual Survey of Manufactures. Obtained through American Fact Finder Database <http://factfinder.census.gov/home/saff/main.html?_lang=en>.

U.S. Department of Commerce, Bureau of the Census. 2003b. 2001 Annual Survey of Manufactures. M01(AS)-2. Washington, DC: Government Printing Office. Available at <http://www.census.gov/prod/2003pubs/m01as-2.pdf>. As obtained on March 4, 2008.

U.S. Department of Commerce, Bureau of the Census, FactFinder. 2011. 2009 Annual Survey of Manufactures. 1996–2011. Obtained through American Fact Finder Database. (Data accessed on October 14, 2011.) [Source for 2007–2009 numbers] <http://factfinder.census.gov/servlet/DatasetMainPageServlet?_lang=en&_ts=336651423017&_ds_name=AM0931GS101&_program=EAS>.

Table 2-13 Imports of Major Petroleum Products (millions of barrels per year)

Year	Motor Gasoline	Jet Fuel	Distillate Fuel Oil	Residual Fuel Oil	Liquefied Petroleum Gases	Other Products	Total
1995	97	35	71	68	53	262	586
1996	123	40	84	91	61	322	721
1997	113	33	83	71	62	345	707
1998	114	45	77	101	71	324	731
1999	139	47	91	86	66	344	774
2000	156	59	108	129	79	343	874
2001	166	54	126	108	75	400	928
2002	182	39	98	91	67	396	872
2003	189	40	122	119	82	397	949
2004	182	47	119	156	96	520	1,119
2005	220	69	120	193	120	587	1,310
2006	173	68	133	128	121	687	1,310
2007	151	79	111	136	90	688	1,255
2008	110	38	78	128	93	700	1,146
2009	82	29	82	121	66	597	977
2010	49	36	83	134	56	584	942

Sources: U.S. Department of Energy, Energy Information Administration (EIA).1996–2007. "Petroleum Supply Annuals, Volume 1." Available at <http://www.eia.doe.gov/oil_gas/petroleum/data_publications/petroleum_supply_annual/psa_volume1/psa_volume1.html>. As obtained on October 31, 2007.

U.S. Department of Energy. 2011 Energy Information Administration (EIA). 1996–2011. "Petroleum Supply Annuals, Volume 1." (Data accessed on October 7, 2011.) [Source for 2007–2010 numbers.] http://www.eia.gov/dnav/pet/pet_move_imp_dc_NUS-Z00_mbbl_a.htm

Table 2-14 Exports of Major Petroleum Products (millions of barrels per year)

Year	Motor Gasoline	Jet Fuel	Distillate Fuel Oil	Residual Fuel Oil	Liquefied Petroleum Gases	Other Products	Total
1995	38	8	67	49	21	128	312
1996	38	17	70	37	19	138	319
1997	50	13	56	44	18	147	327
1998	46	9	45	50	15	139	305
1999	40	11	59	47	18	124	300
2000	53	12	63	51	27	157	362
2001	48	10	44	70	16	159	347
2002	45	3	41	65	24	177	356
2003	46	7	39	72	20	186	370
2004	45	15	40	75	16	183	374
2005	49	19	51	92	19	183	414
2006	52	15	79	103	21	203	472
2007	46	15	98	120	21	213	513
2008	63	22	193	130	25	216	649
2009	71	25	214	152	36	224	723
2010	108	31	239	148	48	270	843

Sources: U.S. Department of Energy, Energy Information Administration (EIA). 1996–2007. "Petroleum Supply Annuals, Volume 1." Available at <http://www.eia.doe.gov/oil_gas/petroleum/data_publications/petroleum_supply_annual/psa_volume1/psa_volume1.html>. As obtained on October 31, 2007.

U.S. Department of Energy. 2011 Energy Information Administration (EIA). 1996–2011. "Petroleum Supply Annuals, Volume 1." (Data accessed on October 7, 2011.) [Source for 2007–2010 numbers] <http://www.eia.gov/dnav/pet/pet_move_exp_dc_NUS-Z00_mbbl_a.htm>.

2.5.4 Market Prices

The average nominal prices of major petroleum products sold to end users are provided for selected years in Table 2-15.[5] As these data illustrate, nominal prices rose substantially between 2005 and 2008. In 2009 there was a drop in prices, resulting in a return to 2005 price levels for most products. In 2010 nominal prices increased. During the 2008–2010 period, the most volatile price was jet fuel price: it declined by 44% in 2009 and increased by 29% in 2010.

[5] Sales to end users are those made directly to the consumer of the product. This includes bulk consumers, such as agriculture, industry, and utilities, as well as residential and commercial consumers.

Table 2-15 Average Price of Major Petroleum Products Sold to End Users (cents per gallon)

Product	1995	2000	2005	2008	2009	2010
Motor gasoline	76.5	110.6	183	278	189	230
No. 1 distillate fuel	62.0	98.8	183	298	214	271
No. 2 distillate fuel	56.0	93.4	178	314	184	232
Jet fuel	54.0	89.9	174	305	170	220
Residual fuel oil	39.2	60.2	105	196	134	171

Note: Prices do not include taxes.

Sources: U.S. Department of Energy, Energy Information Administration (EIA). 2007b. "Refiner Petroleum Product Prices by Sales Type." Available at <http://tonto.eia.doe.gov/dnav/pet/pet_pri_refoth_dcu_nus_m.htm>. As obtained on January 11, 2008.

U.S. Department of Energy. 2011 Energy Information Administration (EIA). 1996–2011. "Petroleum Supply Annuals, Volume 1." (Data accessed on October 7, 2011.) [Source for 2007–2010 numbers.]<http://www.eia.gov/dnav/pet/pet_pri_refoth_dcu_nus_a.htm>.

The nominal prices domestic petroleum refiners receive for their products have been volatile, especially compared to prices received by other U.S. manufacturers. This trend is demonstrated in Table 2-16 by comparing the producer price index (PPI) for the petroleum refining industry against the index for all manufacturing industries. Between 1995 and 2010, prices received by petroleum refineries for their products rose by 288%, while prices received by all manufacturing firms rose by 41%. In 2009, both price indexes experienced a decline from 2008 levels, however the decrease was 36% for petroleum refineries and 5% for all manufacturing firms.

Table 2-16 Producer Price Index Industry Data: 1995 to 2010

	Petroleum Refining (NAICS 32411)		Total Manufacturing Industries	
Year	**PPI**	**Annual Percentage Change in PPI**	**PPI**	**Annual Percentage Change in PPI**
1995	74.5	3%	124.2	3%
1996	85.3	14%	127.1	2%
1997	83.1	−3%	127.5	0%
1998	62.3	−25%	126.2	−1%
1999	73.6	18%	128.3	2%
2000	111.6	52%	133.5	4%
2001	103.1	−8%	134.6	1%
2002	96.3	−7%	133.7	−1%
2003	121.2	26%	137.1	3%
2004	151.5	25%	142.9	4%
2005	205.3	36%	150.8	6%
2006	241.0	17%	156.9	4%
2007	266.9	11%	162.9	4%
2008	338.3	27%	175.8	8%
2009	217.0	−36%	167.1	−5%
2010	289.4	33%	175.4	5%

Sources: U.S. Bureau of Labor Statistics (BLS). 2007. "Producer Price Index Industry Data: Customizable Industry Data Tables." Available at <http://www.bls.gov/ppi/>. As obtained on October 11, 2007.

U.S. Bureau of Labor Statistics (BLS). 2011. "Producer Price Index Industry Data: Customizable Industry Data Tables." (Data accessed on October 11, 2011.) [Source for 2007–2010 numbers]<http://data.bls.gov/cgi-bin/dsrv?pc>.

2.5.5 Profitability of Petroleum Refineries

Estimates of the mean profit (before taxes) to net sales ratios for petroleum refiners are reported in Table 2-17 for the 2006–2007 and 2009-2010 fiscal years. These ratios were calculated by Risk Management Associates by dividing net income into revenues for 44 firms for the 2006-2007 fiscal year and 43 firms for the 2009-2010 fiscal year. They are broken down based on the value of assets owned by the reporting firms.

Table 2-17 Mean Ratios of Profit before Taxes as a Percentage of Net Sales for Petroleum Refiners, Sorted by Value of Assets

Fiscal Year	Total Number of Statements	0 to 500,000	500,000 to 2 Million	2 Million to 10 Million	10 Million to 50 Million	50 Million to 100 Million	100 Million to 250 Million	All Firms
4/1/2006–3/31/2007	44	—	—	4.6	6.5	—	—	6.7
4/1/2009–3/31/2010	43	—	—	5.5	—	—	—	4.1

Sources: Old Source: Risk Management Association (RMA). 2008. *Annual Statement Studies 2007–2008*. Pennsylvania: RMA, Inc.

New Source: Risk Management Association (RMA). 2011. *Annual Statement Studies 2010–2011*. Pennsylvania: RMA, Inc.

As these ratios demonstrate, firms that reported a greater value of assets also received a greater return on sales. For example, for the 2006–2007 fiscal year, firms with assets valued between $10 and $50 million received a 6.5% average return on net sales, while firms with assets valued between $2 and $10 million only received a 4.6% average return. Firms with assets valued between $2 and 10 million received 5.5% average return between 2009 and 2010. The data for other asset size categories is not shown for the fiscal year 2009–2010 because RMA received fewer than 10 financial statements in those categories and RMA does not consider those samples to be representative. The average return on sales for the entire industry was 6.7% during the 2006–2007 fiscal year and declined to 4.1% during the 2009–2010 fiscal year.

Obtaining profitability information specifically for small petroleum refining companies can be difficult as most of these firms are privately owned. However, some of the small, domestic petroleum refining firms identified in Section 3.4.2.3 are publicly owned companies—the Arabian American Development Co., CVR Energy Inc., Calumet Specialty Products Partners, L.P., Holly Corporation, and Western Refining, Inc. Profit ratios were calculated for these companies using data obtained from their publicly available 2010 income statements. These ratios are presented in Table 2-18.

Table 2-18 Net Profit Margins for Publicly Owned, Small Petroleum Refiners: 2010

Company	Net Income ($millions)	Total Revenue ($millions)	Net Profit Margin (%)
Arabian American Development Co.	2.69	139.11	1.93%
Calumet Specialty Products Partners	16.70	2,190.80	0.76%
CVR Energy Inc.	14.30	4,079.80	0.35%
Holly Corporation	133.10	8,323.00	1.60%
Western Refining, Inc.	−17.05	7,965.10	−0.21%

Sources: Holly Corporation, EDGAR database Holly Corporation 10K. February 25, 2011. 10K for year ended December 31, 2010. (Data accessed on 10/23/11) [Source for 2010 numbers.] http://files.shareholder.com/downloads/FTO/1428853845x0xS950123-11-18524/48039/filing.pdf>

Western Refining, Thomson Reuters Western Refining, Inc. 10K. March 8, 2011. 10K for year ended December 31, 2010. (Data accessed on 10/23/11) [Source for 2010 numbers.] http://phx.corporate-ir.net/phoenix.zhtml?c=194293&p=irol-sec>

Arabian American Develop Co., South Hampton Resources, Inc. Arabian American Development Co. Q4 & FY2010 Financial Results. (Data accessed on 10/21/11) [Source for 2010 numbers.] http://www.arabianamericandev.com/images/uploads/investor/2010eoyearningspresentation.pdf>

Calumet Specialty Products Partners, Morningstar for Calumet Specialty Products Partners 10K. February 22, 2011. 10K for year ended December 31, 2010. (Data accessed on 10/21/11) [Source for 2010 numbers.] http://quote.morningstar.com/stock-filing/Annual-Report/2010/12/31/t.aspx?t=XNAS:CLMT&ft=10-K&d=c7dd2813722445ded56c7e3aefebf2ca>

CVR Energy Inc., EDGAR database for CVR Energy Inc. 10K. March 7, 2011. 10K for year ended December 31, 2010. (Data accessed on 10/23/11) [Source for 2010 numbers.] <http://www.sec.gov/Archives/edgar/data/1376139/000095012311022741/y90110e10vk.htm>

2.5.6 Industry Trends

The Energy Information Administration's (EIA's) 2011 Annual Energy Outlook provides forecasts of average petroleum prices, petroleum product consumption, and petroleum refining capacity utilization to the year 2035. Trends in these variables are affected by many factors that are difficult to predict, such as energy prices, U.S. economic growth, advances in technologies, changes in weather patterns, and future public policy decisions. As a result, the EIA evaluated a wide variety of cases based on different assumptions of how these factors will behave in the future. This section focuses on the EIA's "reference case" forecasts, which assume that current policies affecting the energy sector will remain unchanged throughout the projection period (EIA, Form EIA-820).

According to the 2011 Annual Energy Outlook's reference forecast, world oil prices (defined as the average price of low-sulfur, light crude oil) are expected to steadily increase over the next 10 years as the amount of oil demanded by non-OECD and OECD countries increases. Since crude oil is the primary input in petroleum refining, an increase in its price would likewise represent an increase in production costs of petroleum refiners. As a result, the prices of petroleum products sold to end users are expected to rise over the same period (Table 2-19).

Higher prices and tighter fuel efficiency standards (enlarged production of non-oil fuels) will moderate the growth in petroleum products consumed by the recovering US economy (Table 2-20). Between 2011 and 2019, the prices of major petroleum products are expected to rise approximately from 32% to 49%, while consumption of all of those products is expected to rise by 7%. In particular the price of the most supplied product, motor gasoline, is projected to rise by 38% and its consumption is projected to slightly increase by 2%.

Table 2-19 Forecasted Average Price of Major Petroleum Products Sold to End Users in 2009 Currency (cents per gallon)

Product	2011	2012	2013	2014	2015	2016	2017	2018	2019
Motor gasoline	286.1	291.3	312.3	326.9	342.1	353.6	369.5	382.9	395.5
Jet fuel	233.0	252.2	261.8	270.4	280.3	297.9	314.5	330.8	346.1
Distillate fuel	302.6	289.8	301.9	313.9	326.9	345.8	364.1	382.3	400.4
Residual fuel oil	186.2	183.1	191.3	202.9	213.6	225.9	236.8	249.1	259.9
LPGs	178.9	180.5	186.7	193.6	200.4	208	217	226.2	235.4

Sources: U.S. Department of Energy, Energy Information Administration (EIA). 2007c. "Annual Energy Outlook." Available at <http://www.eia.doe.gov/oiaf/archive/aeo07/pdf/0383(2007).pdf>. As obtained on January 21, 2007.

U.S. Department of Energy, Energy Information Administration (EIA). 2011. "Annual Energy Outlook."; (Data accessed on October 11, 2011) [Source for 2011–2019 numbers.] <http://www.eia.gov/forecasts/aeo/pdf/0383(2011).pdf>.

Table 2-20 Total Petroleum Products Supplied (millions of barrels per year)

Year	Motor Gasoline	Jet Fuel	Distillate Fuel Oil	Residual Fuel Oil	Liquefied Petroleum Gases	Other Products	Total
2011	3,317	515	1,367	199	768	806	6,972
2012	3,407	554	1,451	219	823	838	7,291
2013	3,424	555	1,501	218	835	866	7,400
2014	3,429	560	1,501	216	843	876	7,425
2015	3,432	564	1,509	217	848	888	7,459
2016	3,438	569	1,524	217	850	891	7,490
2017	3,416	575	1,538	218	850	891	7,487
2018	3,392	580	1,550	218	850	881	7,472
2019	3,371	585	1,563	218	850	876	7,463

Sources: U.S. Department of Energy, Energy Information Administration (EIA). 2007c. "Annual Energy Outlook." Available at <http://www.eia.doe.gov/oiaf/archive/aeo07/pdf/0383(2007).pdf>. As obtained on January 21, 2007.

U.S. Department of Energy, Energy Information Administration (EIA). 2011. "Annual Energy Outlook."; (Data accessed on October 11, 2011) [Source for 2016–2019 numbers.] <http://www.eia.gov/forecasts/aeo/pdf/0383(2011).pdf>.

Overall, the EIA forecasts that U.S. operational capacity will decrease by a total of 5% between 2011 and 2019 (Table 2-21). The rate of capacity utilization is projected to average 86% during this period.

Table 2-21 Full Production Capacity Utilization Rates for Petroleum Refineries

Year	Petroleum Refineries Capacity Utilization Rates (NAICS 324110)	Gross Input to Atmospheric Crude Oil Distillation Units (1,000s of barrels per day)[6]	Operational Capacity (1,000s of barrels per day)
2011	85.0%	14,946	17,583
2012	83.2%	14,672	17,635
2013	84.2%	14,836	17,626
2014	84.7%	14,851	17,524
2015	84.9%	14,847	17,497
2016	85.6%	14,853	17,342
2017	86.5%	14,827	17,142
2018	87.5%	14,778	16,887
2019	88.2%	14,743	16,706

Sources: U.S. Department of Energy, Energy Information Administration (EIA). 2007c. "Annual Energy Outlook." Available at <http://www.eia.doe.gov/oiaf/archive/aeo07/pdf/0383(2007).pdf>. As obtained on January 21, 2007.

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3 NSPS REGULATORY OPTIONS, COSTS AND EMISSION REDUCTIONS FROM COMPLYING WITH THE NSPS

The emissions reduction and cost impacts presented in this section for flares are revised estimates for the impacts of the final requirements of 40 CFR part 60, subpart Ja for flares, as amended by this action. The impacts are expressed as incremental differences between the impacts of petroleum refinery process units complying with these final amendments to subpart Ja and the final June 2008 NSPS requirements of 40 CFR part 60, subpart Ja (i.e., baseline). The impacts are presented for petroleum refinery flares that commence construction, reconstruction or modification over the next 5 years. We anticipate that there will be 400 affected flares over the next 5 years and most of the flares would become affected due to the modification provisions for flares in subpart Ja. For this analysis we assumed 90 percent of the flares would be modified or reconstructed and 10 percent of the flares would be newly constructed.

Further, we estimate that 30 percent of the 400 affected flares, or 120 flares, either would meet the definition of "emergency flare" in 40 CFR part 60, subpart Ja or would be equipped with a flare gas recovery system such that robust sulfur and flow monitoring would not be required. Therefore, the values presented in this section include the costs and emissions reductions for 400 flares to comply with the flare management plan and root cause and corrective action analyses requirements and for 280 flares to comply with the sulfur and flow monitoring requirements. The cost and emissions reductions for the affected flares to comply with the short-term H2S concentration of 162 ppmv in the fuel gas are included in the baseline rather than the incremental impacts because this limit is unchanged from the requirements in subpart J. For further detail on the methodology of these calculations, see the January 25, 2012 memorandum entitled "Impact Estimates for Fuel Gas Combustion Device and Flare Regulatory Options for Amendments to the Petroleum Refinery NSPS", in Docket ID No. EPA-HQ-OAR-2007-0011.

We estimate that the final requirements for flares will reduce emissions of SO_2 by 3,200 tons per year (tons/yr), NO_x by 1,100 tons/yr, VOC by 3,400 tons/yr, and CO_2 by 1,900,000 metric tons/yr from the baseline. The estimated annual cost, including annualized capital costs for flare gas recovery systems, is $96 million (2006 dollars). The total annual savings from offset natural gas purchases and product recovery credits that arise as a result of complying with

the rule are estimated at $180 million. The estimated net annual cost is a cost savings of $79 million (2006 dollars). Note that not all refiners will realize a cost savings as only flare systems with high waste gas flows (about 10% of all flares) are expected to install vapor recovery systems. The overall cost effectiveness is a cost savings of about $10,000 per ton of combined pollutants (excluding CO_2) removed. The estimated nationwide 5-year incremental emissions reductions and cost impacts for the final standards are summarized in Tables 3-1 and 3-2 below.

Table 3-1. National Cost Impacts for Petroleum Refinery Flares Subject to Amended Standards Under 40 CFR part 60, subpart Ja (Fifth Year After the Effective Date of the Final Rule Amendments)

Subpart Ja Requirements	Total capital cost ($1,000)	Total annual cost without credit ($1,000/yr)	Natural gas offset/ product recovery credit ($1,000)	Total Annual Cost ($1,000/ yr)
Estimates from June 2008 Final Rule	40,000			(7,000)
Total for Revised Estimates for Amendments	460,000	96,000	(180,000)	(79,000)
Flare Monitoring	84,000	14,000	0	14,000
Flare Gas Recovery[7]	380,000	78,000	(170,000)	(90,000)
Flare Management Plans	--	880	--	880
SO2 Root Cause Analysis/Corrective Action	--	2,200	--	2,200
Flow Rate Root Cause Analysis/ Corrective Action	--	1,000	(7,400)	(6,400)

Note: Costs presented in this table are estimated relative to the baseline used for the 2008 NSPS impacts analysis. Additionally, totals may not sum due to independent rounding.

[7] Forty flare systems are estimated to have sufficient waste gas to install recovery systems.

Table 3-2. National Emission Reductions and Cost-Effectiveness for Petroleum Refinery Flares Subject to Amended Standards Under 40 CFR part 60, subpart Ja (Fifth Year After the Effective Date of the Final Rule Amendments)

Subpart Ja Requirements	Annual emission reductions (tons SO_2/yr)	Annual emission reductions (tons NO_x/yr)	Annual emission reductions (tons VOC/yr)	Cost effectiveness ($/ton emissions reduced)	Annual emission reductions (metric tons CO_2/yr)
Estimates from June 2008 Final Rule	80	6	200	(23,000)	--
Total for Revised Estimates for Amendments	3,200	1,100	3,400	(10,000)	1,900,000
Flare Monitoring	0	0	0	--	--
Flare Gas Recovery	380	1,100	2,700	(22,000)	1,800,000
Flare Management Plans	0	0	300	2,900	--
SO2 Root Cause Analysis/Corrective Action	2,900	0	0	760	--
Flow Rate Root Cause Analysis/ Corrective Action	3.4	56	430	(13,000)	98,000

Alternatively, if no refineries install flare gas recovery systems, the final requirements for flares would reduce emissions of SO_2 by 2,820 tons/yr, NO_x by 56 tons/yr, VOC by 730 tons/yr, and CO_2 by 98,000 metric tons/yr from the baseline. The estimated annual cost would be about $10.7 million (2006 dollars).

The provisions for flares and other fuel gas combustion devices (i.e., process heaters and boilers) from the final June 2008 standards were stayed. The analysis for this final rule includes the same unit costs for the flare provisions as the final June 2008 rule but reflects recalculated total costs using data collected in the March 2011 ICR to update the number of flares.[8] Table 3-1 includes the recalculated cost estimates for flares, broken out by specific flare requirements, based on the updated number of flares. For the other fuel gas combustion devices, the total annualized costs for those provisions were estimated at $24 million (2006 dollars) in the June 2008 rule and remain the same. As discussed below, because there are no additional incremental costs associated with the other fuel gas combustion device provisions, we consider those annual costs accounted for in the final June 2008 standards. We are presenting them here again, even

[8] For the June 2008 standards we estimated 40 flares. As indicated, for this analysis we anticipate that there will be 400 affected flares that will be subject to this final rule.

though we estimate no changes to these costs, since these provisions will become effective upon this final action to lift the stay on certain provisions in the June 2008 rule.

The cost, environmental and economic impacts for the final amendments to 40 CFR part 60, subpart Ja for process heaters are not expected to be different than those reported for the final June 2008 standards. We expect owners and operators to install the same technology to meet these final amendments that we anticipated they would install to meet the June 2008 final subpart Ja requirements (i.e., ultra-low NO_x burners). We did revise our emissions estimates based on the type of process heater, creating separate impacts for forced draft process heaters and natural draft process heaters. Dividing process heaters into separate subcategories, based on the draft type, required us to develop new distributions of baseline emissions for each type of process heater. The baseline emissions estimates for natural draft process heaters are slightly lower than those developed for the existing subpart Ja requirements (per affected process heater), but the average emission reduction achieved by ultra-low NO_x burners was adjusted to 80 percent (rather than 75 percent used for generic process heaters). For forced draft process heaters, the baseline (i.e., uncontrolled) emissions rate for forced draft process heaters was revised slightly upward, based on the available emissions data. Because of these differences, the mix of controls needed to meet a 40 ppmv emissions limit was no longer cost effective for forced draft process heaters, but the emission reductions associated with process heaters complying with the 60 ppmv standard were higher than those previously estimated for generic process heaters. Thus, the creation of new subcategories of process heaters with different emissions limits for each subcategory did not impact the control or compliance methods used by the facilities (i.e., BSER in all cases was based on the performance of advanced combustion monitoring controls in conjunction with ultra-low NO_x burners) and did not change the estimated compliance costs. As we do not have adequate data regarding the prevalence of natural draft process heaters versus forced draft process heaters that will become subject to the rule, we used the emission reductions estimated for the two different types of process heaters as a means to bound the range of anticipated NO_x emission reductions to be from 7,100 to 8,600 tons/yr in the fifth year after promulgation (see Revised NO_x Impact Estimates for Process Heaters, in Docket ID No. EPA-HQ-OAR-2007-0011). We estimated the emission reductions to be 7,500 tons/yr for the June 2008 final standards, which falls well within the anticipated range of emissions reductions for the standards

we are finalizing here. Given the uncertainty in the emissions estimates, as well as the uncertainty in the relative number of natural draft process heaters versus forced draft process heaters, we concluded that the impacts previously developed for subpart Ja accurately represent the impacts for process heaters in these final amendments.

We note that, in the preamble to the June 2008 final standards, we estimated costs and emissions reductions for 30 fuel gas combustion devices, but we subsequently determined that those estimates did not fully account for the number of affected flares (which, at the time, were considered a subset of fuel gas combustion devices). Therefore, in the preamble to the December 2008 proposed amendments, we presented revised emission reduction and cost estimates for affected fuel gas combustion devices. Because these final amendments consider flares to be a separate affected source, the emission reductions and costs for fuel gas combustion devices are not affected by these final amendments and are not included in this action. Rather, the final emission reduction and cost estimates for fuel gas combustion devices are very close to the impacts presented in the June 2008 final rule; the details of the analysis and the final impacts are presented in the January 25, 2012 memorandum entitled "Impact Estimates for Fuel Gas Combustion Device and Flare Regulatory Options for Amendments to the Petroleum Refinery NSPS", in Docket ID No. EPA-HQ-OAR-2007-0011.

The final amendments to 40 CFR part 60, subpart J are technical corrections or clarifications to the existing rule and should have no negative emissions impacts.

4 ECONOMIC IMPACT ANALYSIS: METHODS AND RESULTS

4.1 Introduction

The economic impact analysis (EIA) is designed to inform decision makers about the potential economic consequences of a regulatory action. An economic welfare analysis estimates the social costs and consumer and producer surplus changes associated with a regulatory program. The welfare analysis identifies how the regulatory costs are distributed across the two broad classes of stakeholders -- consumers and producers. As defined in EPA's (2010) *Guidelines for Preparing Economic Analyses*,[9] social costs are the value of the goods and services lost by society resulting from using resources to comply with and implement a regulation. In addition, national engineering compliance cost estimates can be used to approximate the welfare impacts of a regulatory program.

Because the proposed amendments apply to new or modifying sources, we are not able to predict which specific sources will trigger applicability. Also, assuming no refineries install fuel gas recovery systems, the estimated, incremental annual costs would be about $10.7 million (2006 dollars), which represents substantially less than 0.001% of total refinery industry revenues in 2010. If we assume a full cost pass through, we do not anticipate any resulting price increases. As such, we did not employ a detailed economic model to estimate the social costs of the proposed amendments, nor to estimate the social cost distribution across stakeholders. For this rule, based on our analysis and an estimated annual cost savings of $79 million (2006 dollars) expected in the fifth year, no national-level negative economic impacts are expected. The remainder of this section includes a discussion of why firms may consider installing flare gas recovery systems, as well as the small business impact analysis.

4.2 Compliance Costs Estimates

As indicated in Section 3, we estimate there are approximately 500 flares industry-wide, and about 80 percent, or 400 flares, would be subject to the proposed amendments over the next five years. We further estimate that it would be cost-effective to install compressors and

[9] These guidelines are currently under review by the Agency.

recovery systems at 10 percent of the 400 flares, or at approximately 40 flares. We assume that a flare gas recovery system would be considered for flares with average releases greater than 500,000 scf per 24-hour period. And while we do not have current data on where all of the potential 40 flares are located, data from the 2002 National Emissions Inventory indicate the flares are likely located at large refineries.[10]

The total annualized engineering compliance costs are estimated at $96 million, and the estimated annual savings from offset natural gas purchases and product recovery credits are estimated at $180 million, giving rise to the net annual savings of $79 million discussed in Section 3. These costs can be broken down into costs required by the rule and costs that are not required by the rule. The annualized compliance costs for actions required by the rule are estimated at $18 million, and the estimated savings from product recovery credits is $7.4 million. Using these figures, we estimate the implied rate of return for actions required by the rule to be about -60 percent. Meanwhile, the annualized compliance costs for actions not required by the rule are estimated at $78 million, and the estimated savings from offset natural gas purchases is $168 million. Using these figures, we estimate the implied rate of return for actions not required by the rule to be about 120 percent and the overall rate of return to be about 90 percent. The actual industry-level rate of return varies greatly over time because of industry and economic factors. See Table 4-1 for refinery rates of return on investment from 2000 through 2009. It is readily observed that the rate of return related to the pollution control equipment and activities by this rule exceeds that of the rate of return associated with investments in the refining sector.

Table 4-1 Rates of Return on Investment for Refineries

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Rate of Return on Investment	9.6	14.5	(1.7)	9.3	18.4	23.2	25.3	21.2	2.4	(6.6)

(EIA 2009)

[10] For details on where flares of this size were located as of the 2002 National Emissions Inventory, see Appendix A of the January 25, 2012 memorandum entitled "Impact Estimates for Fuel Gas Combustion Device and Flare Regulatory Options for Amendments to the Petroleum Refinery NSPS."

Assuming financially rational producers, standard economic theory suggests that refineries 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 process actions (i.e., installation of a flare gas recovery system) that appear to be profitable in our analysis have not been widely adopted. One explanation for why there appears to be negative cost control technologies that are not generally adopted is imperfect information. If process improvements in the refining sector are not well understood, firms may underestimate the potential financial returns to those improvements. Another explanation is the cost associated with the irreversibility of implementing these process improvements is not reflected in the engineering cost estimates. Because of 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 process technology.

If a firm has not adopted the technology on its own, then a regulation encouraging its use means the firm may require reprioritizing other non-environmental investments. Although the rule does not specifically require installation of flare gas recovery systems, we anticipate that owners and operators of flares receiving high waste gas flows will conclude, upon installation of monitors, implementation of their flare management plans, and implementation of root causes analyses, that installing flare gas recovery would result in fuel savings by using the recovered flare gas where purchased natural gas is now being used to fire equipment such as boilers and process heaters. The flare management plan requires refiners to conduct a thorough review of the flare system so that flare gas recovery systems are installed and used where these systems are warranted. As part of the development of the flare management plan, refinery owners and operators must provide rationale and supporting evidence regarding the flare waste gas reduction options considered, the quantity of flare gas that would be recovered or prevented by the option, the BTU content of the flare gas and the ability or inability of the reduction option to offset natural gas purchases. In addition, regulatory requirements imply firms are unable to suspend use of the technology if it becomes unprofitable in the future. Therefore, the true cost of the regulation should include the lost option value, as well as the engineering costs. In the absence of quantitative estimates of this option value, the costs presented in this RIA may underestimate the full costs faced by the affected firms.

4.3 Small Business Impact Analysis

The Regulatory Flexibility Act (RFA) 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. The petroleum refining industry (NAICS code 324110) does not include small governmental jurisdictions or small not-for-profit enterprises. For this analysis we applied the Small Business Administration's small refiner definition of a refinery with no more than 1,500 employees (SBA, 2011). For additional discussion of the Agency's application of the definition for small refiner, see the June 24, 2008 Federal Register Notice for 40 CFR Part 60, Standards of Performance for Petroleum Refineries (Volume 73, Number 122, page 35858).[11]

4.3.1 Small Entity Economic Impact Measures

The analysis provides EPA with an estimate of the magnitude of impacts that the provisions of the proposed standards may have on the ultimate domestic parent companies that own the small refineries. This section references the data sources used in the screening analysis and presents 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 Subpart Ja New Source Performance Standards amendments rely upon data collected through the March 2011 Information Collection Request (ICR -- OMB Control No. 2060-0657). Information collected through component 1 of the ICR includes facility location, products produced, capacity, throughput, process and emissions, and employment and sales receipt data. EPA performed a screening analysis for impacts on all affected small refineries by comparing compliance costs to revenues at the parent company level. This is known as the cost-to-revenue or cost-to-sales ratio, or the "sales test." The "sales test" is

[11] Refer to http://www.sba.gov/sites/default/files/Size_Standards_Table.pdf for more information on SBA small business size standards.

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 frequently 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. The use of a "sales test" for estimating small business impacts for a rulemaking is consistent with guidance offered by EPA on compliance with the RFA[12] and is consistent with guidance published by the U.S. SBA's Office of Advocacy that suggests that cost as a percentage of total revenues is a metric for evaluating cost increases on small entities in relation to increases on large entities (U.S. SBA, 2010).[13]

4.3.2 Small Entity Economic Impact Analysis

As discussed in Section 2 of this RIA, as of January 2011 there were 148 petroleum refineries operating in the continental United States and US territories with a cumulative capacity of processing over 17 million barrels of crude per calendar day (EIA, 2011b). Sixty-four (64) parent companies own these refineries, and EPA has employment and sales data for 61 (95%) of the parent companies. Thirty-six (36) companies (59% of the 61 total) employ fewer than 1,500 workers and are considered small businesses. These firms earned an average of $1.36 billion of revenue per year, while firms employing more than 1,500 employees earned an average of $82.5 billion of revenue per year.[14]

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[12] The RFA compliance guidance to EPA rule writers 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>

[13] 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.

[14] The U.S. Census Bureau's Statistics of U.S. Businesses include the following relevant definitions: (i) **establishment** – a single physical location where business is conducted or where services or industrial operations are performed; (ii) **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; and (iii) **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.

Based on data collected through the March 2011 ICR, EPA performed the sales test analysis for impacts on affected small refineries. Four of the 36 small refiners were removed from the analysis because we determined they were not major sources and would not be subject to the rules, and one of the 36 small refiners (Gulf Atlantic Operations) was not analyzed because we had no ICR and/or other publically available employment and sales data.

While we estimated the natural gas recovery offsets or credit at a national level and believe that larger firms are more likely to offset natural gas purchases, the revenues from natural gas recovery offsets might mask disproportionate impacts on small refiners. At present to better identify disproportionate impacts, we examined the potential impacts on refiners based on a scenario where no firms adopt flare gas recovery systems and comply with the NSPS through flare monitoring and flare management and root cause analysis actions. Refer to Tables 3-1 and 3-2 in the prior Section for details on the costs and emissions reductions associated with each of the potential compliance actions. Table 4-2 presents the distribution of estimated cost-to-sales ratios for the small firms in our analysis. The incremental compliance costs imposed on small refineries are not estimated to create significant impacts on a cost-to-sales ratio basis at the firm level.

Table 4-2 Impact Levels of Proposed NSPS Amendments on Small Firms

Impact Level	Number of Small Firms in Sample Estimated to be Affected	% of Small Firms in Sample Estimated to be Affected
Cost-to-Sales Ratio less than 1%	31	100%
Cost-to-Sales Ratio 1-3%	0	--
Cost-to-Sales Ratio greater than 3%	0	--

For comparison, we calculated the cost-to-sales ratios for all of the affected refineries to determine whether potential costs would have a more significant impact on small refineries. As presented in Table 4-3, for all large firms, the average cost-to-sales ratio is less than 0.01 percent; the median cost-to-sales ratio is less than 0.01 percent; and the maximum cost-to-sales ratio is 0.02 percent. For small firms, the average cost-to-sales ratio is about 0.06 percent, the median cost-to-sales ratio is 0.02 percent, and the maximum cost-to-sales ratio is 0.63 percent. While the potential costs show a somewhat larger impact on small refiners, the impacts on small refiners are not significant. Because no small firms are expected to have cost-to-sales ratios

greater than one percent, we determined that the cost impacts for Subpart Ja New Source Performance Standards amendments will not have a significant economic impact on a substantial number of small entities (SISNOSE).

Table 4-3 Summary of Sales Test Ratios for Firms Affected by Proposed NSPS Amendments

Firm Size	No. of Known Affected Firms	% of Total Known Affected Firms	Mean Cost-to-Sales Ratio	Median Cost-to-Sales Ratio	Min. Cost-to-Sales Ratio	Max. Cost-to-Sales Ratio
Small	31	55%	0.06%	0.02%	<0.01%	0.63%
Large	25	45%	<0.01%	<0.01%	<0.01%	0.02%
All	56	100%	0.02%	<0.01%	<0.01%	0.63%

4.4 References

U.S. Department of Energy, 2009 Energy Information Administration (EIA). "Performance Profiles of Major Energy Producers 2009." (Data accessed on March 5, 2012.) <http://www.eia.gov/cfapps/frs/frstables.cfm?tableNumber=9>

U.S. Environmental Protection Agency, 2010. Guidelines for Preparing Economic Analyses, EPA 240-R-10-001. <http://yosemite.epa.gov/ee/epa/eed.nsf/pages/Guidelines.html> Accessed on: 11/14/11.

5 EXECUTIVE ORDERS

5.1 Unfunded Mandates

This rule does not contain a Federal mandate that may result in expenditures of $100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in any one year. The costs of the final amendments would not increase costs associated with the final rule. Thus, this rule is not subject to the requirements of sections 202 or 205 of the Unfunded Mandates Reform Act of 1995 (UMRA).

This 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. The proposed amendments contain no requirements that apply to such governments, and impose no obligations upon them.

5.2 Environmental Justice

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.

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 or low-income population. This rule is a nationwide standard that will yield reductions in various criteria pollutant emissions from new, modified, and reconstructed process heaters and flares at petroleum refineries, thus decreasing the amount of such emissions to which all affected populations are exposed.

5.3 Significant Energy Actions

These proposed amendments do not represent a “significant energy action” as defined in Executive Order 13211, “Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use” (66 FR 28355 [May 22, 2001]) because they are not likely to have

a significant adverse effect on the supply, distribution, or use of energy. Assuming no refineries install a flare gas recovery system, the estimated annualized compliance costs for the proposed requirements are substantially less than 0.001% of total refinery industry revenues in 2010. Assuming a full cost pass through, we do not anticipate any resulting price increases, and we estimate there will be no significant increase in our dependence on foreign energy supplies. Finally, today's action will have no adverse effect on crude oil supply, coal production, electricity production, and energy distribution. Based on the findings from the analysis of impacts on energy markets, we conclude that today's action is not a "significant energy action" as defined in Executive Order 13211.

6 HUMAN HEALTH BENEFITS OF EMISSIONS REDUCTIONS

Synopsis

In this section, we provide an estimate of the monetized benefits for the final Petroleum Refineries NSPS Reconsideration associated with reducing exposure to ambient particulate matter (PM) by reducing emissions of $PM_{2.5}$ precursors including SO_2, NOx, and VOCs, as well as climate benefits associated with reducing emissions of CO_2. SO_2, NOx, and VOCs are precursors to $PM_{2.5}$, and NOx and VOCs are precursors to ozone. These estimates reflect the monetized human health benefits of reducing cases of morbidity and premature mortality among populations exposed to $PM_{2.5}$ reduced by this reconsideration. We estimate the total monetized benefits to be $260 million to $580 million at a 3% discount rate and $240 million to $520 million at a 7% discount rate. All estimates are in 2006$ in the year 2017.

These estimates reflect EPA's most current interpretation of the scientific literature. Higher or lower estimates of benefits are possible using other assumptions; examples of this are provided in Figure 6-2 on page 6-14). Data, resource, and methodological limitations prevented EPA from monetizing the benefits from several important benefit categories, including benefits from reducing direct exposure to NO_2 and SO_2, ozone exposure, ecosystem effects, and visibility impairment.

6.1 Calculation of $PM_{2.5}$-Related Human Health Benefits

This final NSPS Reconsideration would reduce emissions of SO_2, NO_X, and VOCs. Because these emissions are precursors to $PM_{2.5,}$ reducing these emissions would also reduce $PM_{2.5}$ formation, human exposure and the incidence of $PM_{2.5}$-related health effects. Due to analytical limitations, it was not possible to provide a comprehensive estimate of $PM_{2.5}$-related benefits or provide estimates of the health benefits associated with direct exposure to SO_2 and NOx or exposure to ozone. Instead, we used the "benefit-per-ton" approach to estimate these benefits. The methodology employed in this analysis is similar to the work described in Fann, Fulcher, and Hubbell (2009), but represents an improvement that EPA believes will provide more reliable estimates of $PM_{2.5}$-related health benefits for emissions reductions in specific sectors. The key assumptions are described in detail below. These $PM_{2.5}$ benefit-per-ton estimates provide the total monetized human health benefits (the sum of premature mortality and premature morbidity) of reducing one ton of $PM_{2.5}$ from a specified source. EPA has used the

benefit per-ton technique in several previous RIAs, including the recent SO_2 NAAQS RIA (U.S. EPA, 2010).

The *Integrated Science Assessment* (ISA) *for Particulate Matter* (U.S. EPA, 2009b) identified the human health effects associated with ambient $PM_{2.5,}$ which include premature morality and a variety of morbidity effects associated with acute and chronic exposures. Table 6-1 shows the quantified and unquantified benefits captured in those benefit-per-ton estimates, but this table does not include entries for the unquantified health effects associated with exposure to ozone, SO_2, and NOx nor welfare effects such as ecosystem effects and visibility that are described in section 6.2. It is important to emphasize that the list of unquantified benefit categories is not exhaustive, nor is quantification of each effect complete.

Table 6-1: Human Health Effects of $PM_{2.5}$

Category	Specific Effect	Effect Has Been Quantified	Effect Has Been Monetized	More Information (refers to CSAPR RIA)
Improved Human Health				
Reduced incidence of premature mortality from exposure to $PM_{2.5}$	Adult premature mortality based on cohort study estimates and expert elicitation estimates (age >25 or age >30)	✓	✓	Section 5.4
	Infant mortality (age <1)	✓	✓	Section 5.4
Reduced incidence of morbidity from exposure to $PM_{2.5}$	Non-fatal heart attacks (age > 18)	✓	✓	Section 5.4
	Hospital admissions—respiratory (all ages)	✓	✓	Section 5.4
	Hospital admissions—cardiovascular (age >20)	✓	✓	Section 5.4
	Emergency room visits for asthma (all ages)	✓	✓	Section 5.4
	Acute bronchitis (age 8-12)	✓	✓	Section 5.4
	Lower respiratory symptoms (age 7-14)	✓	✓	Section 5.4
	Upper respiratory symptoms (asthmatics age 9-11)	✓	✓	Section 5.4
	Asthma exacerbation (asthmatics age 6-18)	✓	✓	Section 5.4
	Lost work days (age 18-65)	✓	✓	Section 5.4
	Minor restricted-activity days (age 18-65)	✓	✓	Section 5.4
	Chronic Bronchitis (age >26)	✓	✓	Section 5.4
	Emergency room visits for cardiovascular effects (all ages)	--	--	Section 5.4
	Strokes and cerebrovascular disease (age 50-79)	--	--	Section 5.4
	Other cardiovascular effects (e.g., other ages)	--	--	PM ISA[2]
	Other respiratory effects (e.g., pulmonary function, non-asthma ER visits, non-bronchitis chronic diseases, other ages and populations)	--	--	PM ISA[2]
	Reproductive and developmental effects (e.g., low birth weight, pre-term births, etc)	--	--	PM ISA[2,3]
	Cancer, mutagenicity, and genotoxicity effects	--	--	PM ISA[2,3]

[1] We assess these benefits qualitatively due to time and resource limitations for this analysis.
[2] We assess these benefits qualitatively because we do not have sufficient confidence in available data or methods.
[3] We assess these benefits qualitatively because current evidence is only suggestive of causality or there are other significant concerns over the strength of the association.

Consistent with the Portland Cement NESHAP (U.S. EPA, 2009a), the benefits estimates utilize the concentration-response functions as reported in the epidemiology literature, as well as the 12 functions obtained in EPA's expert elicitation study as a sensitivity analysis.

- One estimate is based on the concentration-response (C-R) function developed from the extended analysis of American Cancer Society (ACS) cohort, as reported in Pope et al. (2002), a study that EPA has previously used to generate its primary benefits estimate. When calculating the estimate, EPA applied the effect coefficient as reported in the study without an adjustment for assumed concentration threshold of 10 $\mu g/m^3$ as was done in recent (2006-2009) Office of Air and Radiation RIAs.
- One estimate is based on the C-R function developed from the extended analysis of the Harvard Six Cities cohort, as reported by Laden et al (2006). This study, published after the completion of the Staff Paper for the 2006 $PM_{2.5}$ NAAQS, has been used as an alternative estimate in the $PM_{2.5}$ NAAQS RIA and $PM_{2.5}$ benefits estimates in RIAs completed since the $PM_{2.5}$ NAAQS. When calculating the estimate, EPA applied the effect coefficient as reported in the study without an adjustment for assumed concentration threshold of 10 $\mu g/m^3$ as was done in recent (2006-2009) RIAs.
- Twelve estimates are based on the C-R functions from EPA's expert elicitation study (Roman et al., 2008) on the $PM_{2.5}$ -mortality relationship and interpreted for benefits analysis in EPA's final RIA for the $PM_{2.5}$ NAAQS. For that study, twelve experts (labeled A through L) provided independent estimates of the $PM_{2.5}$ -mortality concentration-response function. EPA practice has been to develop independent estimates of $PM_{2.5}$ -mortality estimates corresponding to the concentration-response function provided by each of the twelve experts, to better characterize the degree of variability in the expert responses.

The effect coefficients are drawn from epidemiology studies examining two large population cohorts: the American Cancer Society cohort (Pope et al., 2002) and the Harvard Six Cities cohort (Laden et al., 2006).[15] These are logical choices for anchor points in our presentation because, while both studies are well designed and peer reviewed, there are strengths and weaknesses inherent in each, which we believe argues for using both studies to generate benefits estimates. Previously, EPA had calculated benefits based on these two empirical studies, but derived the range of benefits, including the minimum and maximum results, from an expert elicitation of the relationship between exposure to $PM_{2.5}$ and premature mortality (Roman

[15] These two studies specify multi-pollutant models that control for SO_2, among other co-pollutants.

et al., 2008).[16] Within this assessment, we include the benefits estimates derived from the concentration-response function provided by each of the twelve experts to better characterize the uncertainty in the concentration-response function for mortality and the degree of variability in the expert responses. Because the experts used these cohort studies to inform their concentration-response functions, benefits estimates using these functions generally fall between results using these epidemiology studies (see Figure 6-2). In general, the expert elicitation results support the conclusion that the benefits of $PM_{2.5}$ control are very likely to be substantial.

Readers interested in reviewing the general methodology for creating the benefit-per-ton estimates used in this analysis should consult the draft Technical Support Document (TSD) on estimating the benefits per ton of reducing $PM_{2.5}$ and its precursors from the petroleum refineries sector specifically (U.S. EPA, 2012). The primary difference between the estimates used in this analysis and the estimates reported in Fann, Fulcher, and Hubbell (2009) is the air quality modeling data utilized. While the air quality data used in Fann, Fulcher, and Hubbell (2009) reflects broad pollutant/source category combinations, such as all non-EGU stationary point sources, the air quality modeling data used in this analysis is sector-specific. In addition, the updated air quality modeling data reflects more recent emissions data (2005 rather than 2001) and has a higher spatial resolution (12km rather than 36 km grid cells). As a result, the benefit-per-ton estimates presented herein better reflect the geographic areas and populations likely to be affected by this sector. The benefits methodology, such as health endpoints assessed, risk estimates applied, and valuation techniques, applied did not change. As noted below in the characterization of uncertainty, these updated estimates still have similar limitations as all national-average benefit-per-ton estimates in that they reflect the geographic distribution of the modeled emissions, which may not exactly match the emission reductions in this rulemaking, and they may not reflect local variability in population density, meteorology, exposure, baseline health incidence rates, or other local factors for any specific location. In this analysis, we apply these national benefit-per-ton estimates calculated for this sector separately for SO_2 and NOx and multiply them by the corresponding emission reductions.

These models assume 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 effects estimates by particle type. SO_2 and NOx are the primary $PM_{2.5}$ precursors affected by this rule. Even though we assume that all fine particles have equivalent

[16] Please see the Section 5.2 of the Portland Cement RIA in Appendix 5A for more information regarding the change in the presentation of benefits estimates.

health effects, the benefit-per-ton estimates vary between precursors depending on the location and magnitude of their impact on $PM_{2.5}$ levels, which drive population exposure. The sector-specific modeling does not provide estimates of the $PM_{2.5}$-related benefits associated with reducing VOC emissions, but these unquantified benefits are generally small compared to other $PM_{2.5}$ precursors (U.S. EPA, 2012).

The benefit-per-ton coefficients in this analysis were derived using modified versions of the health impact functions used in the PM NAAQS Regulatory Impact Analysis (U.S. EPA, 2006). Specifically, this analysis uses the benefit-per-ton method first applied in the Portland Cement NESHAP RIA (U.S. EPA, 2009a), which incorporated three updates: a new population dataset, an expanded geographic scope of the benefit-per-ton calculation, and the functions directly from the epidemiology studies without an adjustment for an assumed threshold.[17] Removing the threshold assumption is a key difference between the method used in this analysis of PM benefits and the methods used in RIAs prior to Portland Cement proposal, and we now calculate incremental benefits down to the lowest modeled $PM_{2.5}$ air quality levels.

Based on our review of the current body of scientific literature, EPA now estimates PM-related mortality without applying an assumed concentration threshold. EPA's *Integrated Science Assessment for Particulate Matter* (U.S. EPA, 2009b), which was reviewed by EPA's Clean Air Scientific Advisory Committee (U.S. EPA-SAB, 2009a; U.S. EPA-SAB, 2009b), concluded that the scientific literature consistently finds that a no-threshold log-linear model most adequately portrays the PM-mortality concentration-response relationship while recognizing potential uncertainty about the exact shape of the concentration-response function.

Consistent with this finding, we have conformed the previous threshold sensitivity analysis to the current state of the PM science by incorporating a "Lowest Measured Level" (LML) assessment, which is a method EPA has employed in several recent RIAs including the Cross-State Air Pollution Rule (U.S. EPA, 2011b). This information allows readers to determine the portion of population exposed to annual mean $PM_{2.5}$ levels at or above the LML of each study; in general, our confidence in the estimated PM mortality decreases as we consider air quality levels further below the LML in major cohort studies that estimate PM-related mortality. While an LML assessment provides some insight into the level of uncertainty in the estimated

[17] The benefit-per-ton estimates have also been updated since the Portland Cement RIA to incorporate a revised VSL, as discussed below.

PM mortality benefits, EPA does not view the LML as a threshold and continues to quantify PM-related mortality impacts using a full range of modeled air quality concentrations. It is important to emphasize that we have high confidence in $PM_{2.5}$-related effects down to the lowest LML of the major cohort studies, which is 5.8 μg/m^3. Just because we have greater confidence in the benefits above the LML, this does not mean that we have no confidence that benefits occur below the LML. For a summary of the scientific review statements regarding the lack of a threshold in the $PM_{2.5}$-mortality relationship, see the Technical Support Document (TSD) entitled *Summary of Expert Opinions on the Existence of a Threshold in the Concentration-Response Function for $PM_{2.5}$-related Mortality* (U.S. EPA, 2010b).

For this analysis, policy-specific air quality data is not available due to time or resource limitations. For these rules, we are unable to estimate the percentage of premature mortality associated with this specific rule's emission reductions at each $PM_{2.5}$ level. However, we believe that it is still important to characterize the distribution of exposure to baseline air quality levels. As a surrogate measure of mortality impacts, we provide the percentage of the population exposed at each $PM_{2.5}$ level using the source apportionment modeling used to calculate the benefit-per-ton estimates for this sector. It is important to note that baseline exposure is only one parameter in the health impact function, along with baseline incidence rates population, and change in air quality. In other words, the percentage of the population exposed to air pollution below the LML is not the same as the percentage of the population experiencing health impacts as a result of a specific emission reduction policy. The most important aspect, which we are unable to quantify for rules without rule-specific air quality modeling, is the shift in exposure associated with this specific rule. Therefore, caution is warranted when interpreting the LML assessment for this rule. The results of this analysis are provided in Section 6.3.

As is the nature of RIAs, the assumptions and methods used to estimate air quality benefits evolve over time to reflect the Agency's most current interpretation of the scientific and economic literature. For a period of time (2004-2008), the Office of Air and Radiation (OAR) valued mortality risk reductions using a value of statistical life (VSL) estimate derived from a limited analysis of some of the available studies. OAR arrived at a VSL using a range of $1 million to $10 million (2000$) consistent with two meta-analyses of the wage-risk literature. The $1 million value represented the lower end of the interquartile range from the Mrozek and Taylor (2002) meta-analysis of 33 studies. The $10 million value represented the upper end of

the interquartile range from the Viscusi and Aldy (2003) meta-analysis of 43 studies. The mean estimate of $5.5 million (2000$)[18] was also consistent with the mean VSL of $5.4 million estimated in the Kochi et al. (2006) meta-analysis. However, the Agency neither changed its official guidance on the use of VSL in rulemakings nor subjected the interim estimate to a scientific peer-review process through the Science Advisory Board (SAB) or other peer-review group.

During this time, the Agency continued work to update its guidance on valuing mortality risk reductions, including commissioning a report from meta-analytic experts to evaluate methodological questions raised by EPA and the SAB on combining estimates from the various data sources. In addition, the Agency consulted several times with the Science Advisory Board Environmental Economics Advisory Committee (SAB-EEAC) on the issue. With input from the meta-analytic experts, the SAB-EEAC advised the Agency to update its guidance using specific, appropriate meta-analytic techniques to combine estimates from unique data sources and different studies, including those using different methodologies (i.e., wage-risk and stated preference) (U.S. EPA-SAB, 2007).

Until updated guidance is available, the Agency determined that a single, peer-reviewed estimate applied consistently best reflects the SAB-EEAC advice it has received. Therefore, the Agency has decided to apply the VSL that was vetted and endorsed by the SAB in the Guidelines for Preparing Economic Analyses (U.S. EPA, 2000)[19] while the Agency continues its efforts to update its guidance on this issue. This approach calculates a mean value across VSL estimates derived from 26 labor market and contingent valuation studies published between 1974 and 1991. The mean VSL across these studies is $6.3 million (2000$).[20] The Agency is committed to using scientifically sound, appropriately reviewed evidence in valuing mortality risk reductions and has made significant progress in responding to the SAB-EEAC's specific recommendations.

In implementing these rules, emission controls may lead to reductions in ambient $PM_{2.5}$ below the National Ambient Air Quality Standards (NAAQS) for PM in some areas and assist

[18] After adjusting the VSL for a different currency year (2006$) and to account for income growth to 2015 of the $5.5 million value, the VSL is $7.4 million.

[19] In revised Economic Guidelines (U.S. EPA, 2010c), EPA retained the VSL endorsed by the SAB with the understanding that further updates to the mortality risk valuation guidance would be forthcoming in the near future. Therefore, this report does not represent final agency policy.

[20] In this analysis, we adjust the VSL to account for a different currency year ($2006) and to account for income growth to 2015. After applying these adjustments to the $6.3 million value, the VSL is $8.5 million.

other areas with attaining the PM NAAQS. Because the PM NAAQS RIAs also calculate 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 the illustrative $PM_{2.5}$ NAAQS RIA.

By contrast, the emission reductions for implementation rules are 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, 2010a).

Figure 6.1 illustrates the relative breakdown of the monetized $PM_{2.5}$ health benefits.

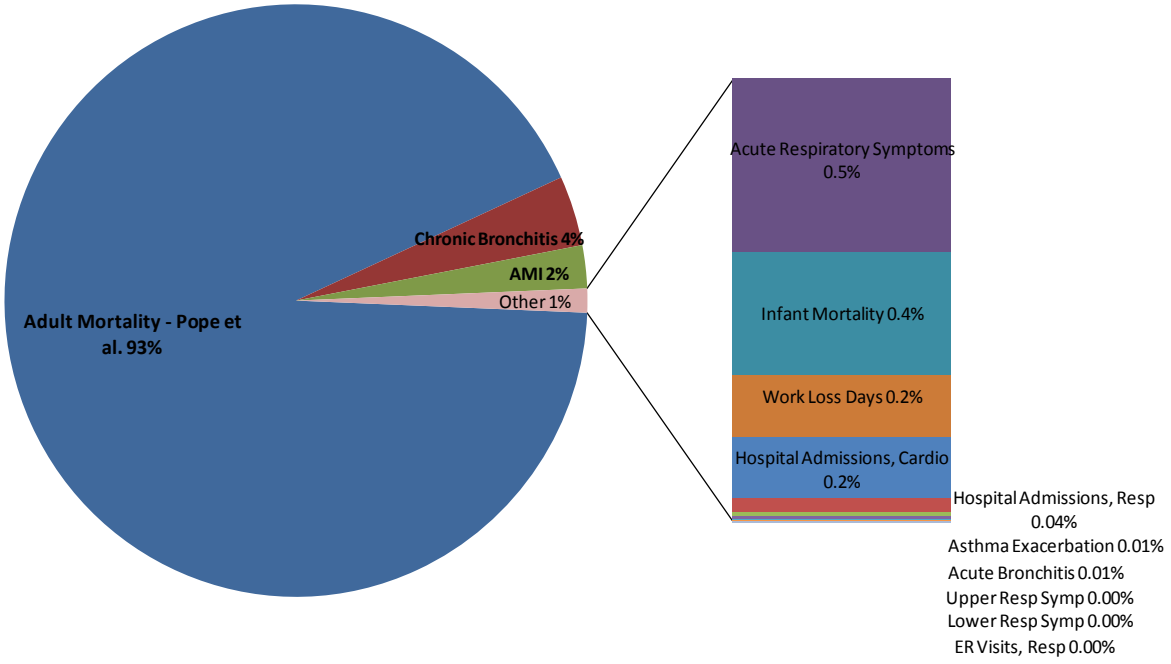


Figure 6-1: Breakdown of Monetized $PM_{2.5}$ Health Benefits using Mortality Function from Pope et al. (2002)*

*This pie chart breakdown is illustrative, using the results based on Pope et al. (2002) as an example. Using the Laden et al. (2006) function for premature mortality, the percentage of total monetized benefits due to adult mortality would be 97%. This chart shows the breakdown using a 3% discount rate, and the results would be similar if a 7% discount rate was used.

Table 6-2 provides a general summary of the monetized PM-related health benefits by precursor, including the emission reductions and benefit-per-ton estimates at discount rates of 3% and 7%.[21] Table 6-3 provides a summary of the reductions in health incidences as a result of the pollution reductions. In Table 6-4, we provide the benefits using our anchor points of Pope et al. and Laden et al. as well as the results from the expert elicitation on PM mortality. Figure

[21] To comply with Circular A-4, EPA provides monetized benefits using discount rates of 3% and 7% (OMB, 2003). These benefits are estimated for a specific analysis year (i.e., 2017), and most of the PM benefits occur within that year with two exceptions: acute myocardial infarctions (AMIs) and premature mortality. For AMIs, we assume 5 years of follow-up medical costs and lost wages. For premature mortality, we assume that there is a "cessation" lag between PM exposures and the total realization of changes in health effects. Although the structure of the lag is uncertain, EPA follows the advice of the SAB-HES to assume a segmented lag structure characterized by 30% of mortality reductions in the first year, 50% over years 2 to 5, and 20% over the years 6 to 20 after the reduction in $PM_{2.5}$ (U.S. EPA-SAB, 2004). Changes in the lag assumptions do not change the total number of estimated deaths but rather the timing of those deaths. Therefore, discounting only affects the AMI costs after the analysis year and the valuation of premature mortalities that occur after the analysis year. As such, the monetized benefits using a 7% discount rate are only approximately 10% less than the monetized benefits using a 3% discount rate.

6-2 provides a visual representation of the range of $PM_{2.5}$-related benefits estimates using concentration-response functions supplied by experts.

Table 6-2: General Summary of Monetized PM-Related Health Benefits Estimates for Petroleum Refineries NSPS Reconsideration (millions of 2006$)*

	Pollutant	Emissions Reductions (tons)	Benefit per ton (Pope, 3%)	Benefit per ton (Laden, 3%)	Benefit per ton (Pope, 7%)	Benefit per ton (Laden, 7%)	Total Monetized Benefits (millions of 2006$ at 3%)	Total Monetized Benefits (millions of 2006$ at 7%)
	$PM_{2.5}$ Precursors							
Small Flares	SO_2	2,600	$65,000	$160,000	$58,000	$140,000	$170 to $410	$150 to $370
	NO_X	50	$6,400	$16,000	$5,700	$14,000	$.32 to $.79	$.29 to $.71
						Total	**$170 to $410**	**$150 to $370**
	$PM_{2.5}$ Precursors							
Large Flares	SO_2	660	$65,000	$160,000	$58,000	$140,000	$43 to $100	$38 to $94
	NO_X	1,100	$6,400	$16,000	$5,700	$14,000	$6.80 to $17.00	$6.10 to $15.00
						Total	**$49 to $120**	**$44 to $110**
	$PM_{2.5}$ Precursors							
All Flares	SO_2	3,200	$65,000	$160,000	$58,000	$140,000	$210 to $510	$190 to $460
	NO_X	1,100	$6,400	$16,000	$5,700	$14,000	$7.1 to $18.0	$6.4 to $16
						Total	**$220 to $530**	**$190 to $480**

* All estimates are for the analysis year (2017), and are rounded to two significant figures so numbers may not sum across columns. It is important to note that the monetized benefits do not include reduced health effects from direct exposure to SO_2 and NOx, ozone exposure, ecosystem effects, or visibility impairment. These estimates do not include CO_2 benefits estimated at $46 million (3% discount rate). All fine particles are assumed to have equivalent health effects, but the benefit per ton estimates vary because each ton of precursor reduced has a different propensity to form $PM_{2.5}$. The monetized benefits incorporate the conversion from precursor emissions to ambient fine particles. Confidence intervals are unavailable for this analysis because of the benefit-per-ton methodology.

Table 6-3: Summary of Reductions in Health Incidences from $PM_{2.5}$ Benefits for the Final Petroleum Refineries NSPS Reconsideration*

Avoided Premature Mortality	
Pope et al.	26
Laden et al.	66
Avoided Morbidity	
Chronic Bronchitis	19
Emergency Department Visits, Respiratory	19
Hospital Admissions, Respiratory	5
Hospital Admissions, Cardiovascular	10
Acute Bronchitis	43
Lower Respiratory	550
Upper Respiratory	420
Minor Restricted Activity Days	23,000
Work Loss Days	3,800
Asthma Exacerbation	920
Acute Myocardial Infarction	27

* All estimates are for the analysis year (2017) and are rounded to whole numbers with two significant figures. All fine particles are assumed to have equivalent health effects because the scientific evidence is not yet sufficient to allow differentiation of effects estimates by particle type. Confidence intervals are unavailable for this analysis because of the benefit-per-ton methodology.

Table 6-4: All $PM_{2.5}$ Benefits Estimates for the Final Petroleum Refineries NSPS Reconsideration at discount rates of 3% and 7% in 2017 (in millions of 2006$)*

	3%	7%
Benefit-per-ton Coefficients Derived from Epidemiology Literature		
Pope et al.	$220	$190
Laden et al.	$530	$480
Benefit-per-ton Coefficients Derived from Expert Elicitation		
Expert A	$560	$510
Expert B	$430	$380
Expert C	$430	$380
Expert D	$300	$270
Expert E	$700	$630
Expert F	$390	$350
Expert G	$260	$230
Expert H	$320	$290
Expert I	$420	$380
Expert J	$350	$310
Expert K	$83	$74
Expert L	$290	$260

*All estimates are rounded to two significant figures. These estimates do not include CO_2 benefits estimated at $49 million (3% discount rate). The benefits estimates from the Expert Elicitation are provided as a reasonable characterization of the uncertainty in the mortality estimates associated with the concentration-response function. Confidence intervals are unavailable for this analysis because of the benefit-per-ton methodology

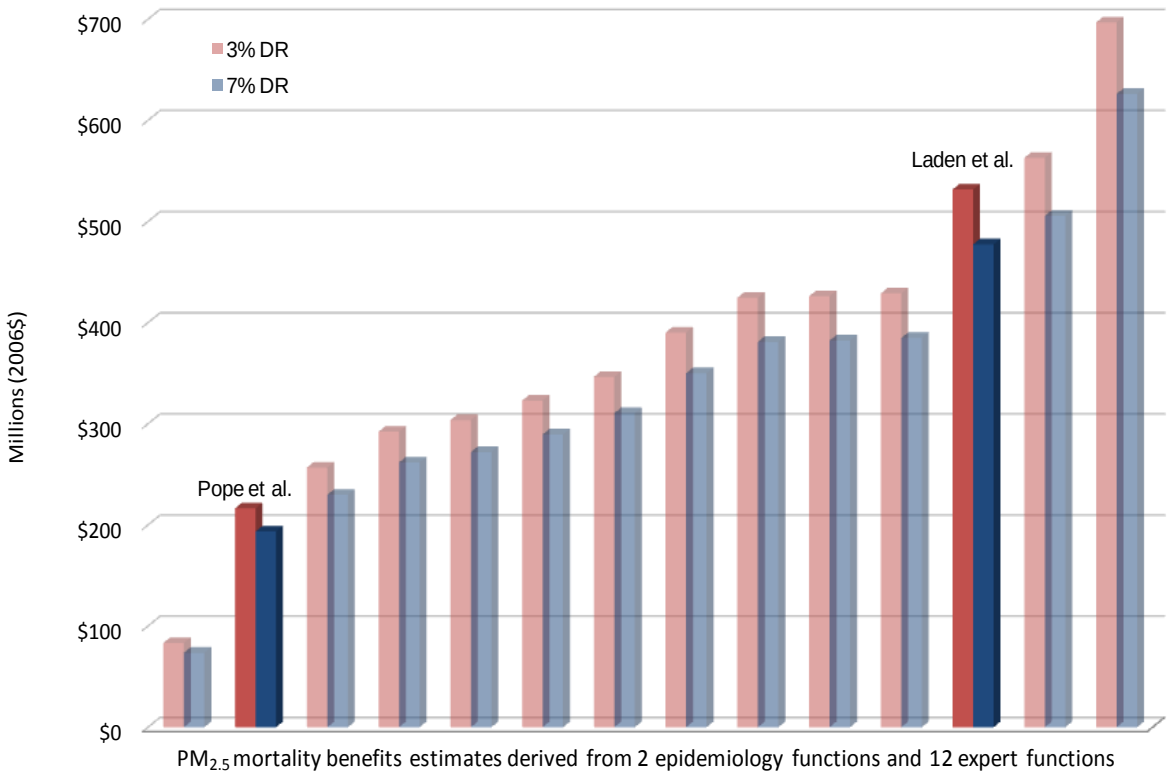


Figure 6-2: Monetized $PM_{2.5}$ Benefits of Final Petroleum Refineries Reconsideration in 2017

*This graph shows the estimated benefits at discount rates of 3% and 7% using effect coefficients derived from the Pope et al. study and the Laden et al study, as well as 12 effect coefficients derived from EPA's expert elicitation on PM mortality. The results shown are not the direct results from the studies or expert elicitation; rather, the estimates are based in part on the concentration-response function provided in those studies. These estimates do not include CO_2 benefits estimated at $46 million (3% discount rate).

6.2 Social Cost of Carbon and Greenhouse Gas Benefits

EPA has assigned a dollar value to reductions in carbon dioxide (CO_2) emissions using recent estimates of the "social cost of carbon" (SCC). The SCC is an estimate of the monetized damages associated with an incremental increase in carbon emissions in a given year. It is intended to include (but is not limited to) changes in net agricultural productivity, human health, property damages from increased flood risk, and the value of ecosystem services due to climate change. The SCC estimates used in this analysis were developed through an interagency process that included EPA and other executive branch entities, and concluded in February, 2010. EPA first used these SCC estimates in the benefits analysis for the final joint EPA/DOT Rulemaking to establish Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards; see the rule's preamble for discussion about application of SCC (75

FR 25324; 5/7/10). The SCC Technical Support Document (SCC TSD) provides a complete discussion of the methods used to develop these SCC estimates.[22]

The interagency group selected four SCC values for use in regulatory analyses, which we have applied in this analysis: $5, $21, $35, and $65 per metric ton of CO_2 emissions[23] in 2010, in 2007 dollars. The first three values are based on the average SCC from three integrated assessment models, at discount rates of 2.5, 3, and 5 percent, respectively. SCCs at several 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 SCC from all three models at a 3 percent discount rate. It is included to represent higher-than-expected impacts from temperature change further out in the tails of the SCC distribution. Low probability, high impact events are incorporated into all of the SCC values through explicit consideration of their effects in two of the three models as well as the use of a probability density function for equilibrium climate sensitivity. Treating climate sensitivity probabilistically results in more high temperature outcomes, which in turn lead to higher projections of damages.

The SCC increases over time because future emissions are expected to produce larger incremental damages as physical and economic systems become more stressed in response to greater climatic change. Note that the interagency group estimated the growth rate of the SCC directly using the three integrated assessment models rather than assuming a constant annual growth rate. This helps to ensure that the estimates are internally consistent with other modeling assumptions. The SCC estimates for the analysis years of 2014, in 2005 dollars are provided in Table 6-5.

[22]Docket ID EPA-HQ-OAR-2009-0472-114577, *Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866,* Interagency Working Group on Social Cost of Carbon, with participation by Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Environmental Protection Agency, National Economic Council, Office of Energy and Climate Change, Office of Management and Budget, Office of Science and Technology Policy, and Department of Treasury (February 2010). Also available at http://www.epa.gov/otaq/climate/regulations.htm

[23]The interagency group decided that these estimates apply only to CO_2 emissions. Given that warming profiles and impacts other than temperature change (e.g., ocean acidification) vary across GHGs, the group concluded "transforming gases into CO_2-equivalents using GWP, and then multiplying the carbon-equivalents by the SCC, would not result in accurate estimates of the social costs of non-CO_2 gases" (SCC TSD, pg 13).

Table 6-5. Social Cost of Carbon (SCC) Estimates (per tonne of CO_2) for 2017[a]

Discount Rate and Statistic	SCC estimate (2006$)
5% (Average)	$5.9
3% (Average)	$24.1
2.5% (Average)	$38.6
3% (95th percentile)	$73.9

[a] The SCC values are dollar-year and emissions-year specific. SCC values represent only a partial accounting of climate impacts.

When attempting to assess the incremental economic impacts of carbon dioxide emissions, the analyst faces a number of serious challenges. A recent report from the National Academies of Science (NRC, 2009) points out that any assessment will suffer from uncertainty, speculation, and lack of information about (1) future emissions of greenhouse gases, (2) the effects of past and future emissions on the climate system, (3) the impact of changes in climate on the physical and biological environment, and (4) the translation of these environmental impacts into economic damages. As a result, any effort to quantify and monetize the harms associated with climate change will raise serious questions of science, economics, and ethics and should be viewed as provisional.

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 the interagency modeling exercise 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.

In light of these limitations, the interagency group has committed to updating the current estimates as the science and economic understanding of climate change and its impacts on society improves over time. Specifically, the interagency group has set a preliminary goal of revisiting the SCC values within two years or at such time as substantially updated models become available, and to continue to support research in this area.

Applying the global SCC estimates to the estimated reductions in CO_2 emissions for the range of policy scenarios, we estimate the dollar value of the climate-related benefits captured by the models for each analysis year. For internal consistency, the annual benefits are discounted back to net present value (NPV) terms using the same discount rate as each SCC estimate (i.e., 5%, 3%, and 2.5%) rather than 3% and 7%.[24] These estimates are provided in Table 6-6.

Table 6-6. Monetized SCC-Derived Benefits of CO_2 Emission Reductions in 2017 [a,b]

Discount Rate and Statistic	Monetized Climate Benefits with flare gas recovery (millions of 2006$)	Monetized Climate Benefits without flare gas recovery (millions of 2006$)
Tonnes of CO_2	1,900,000	110,000
5% (Average)	$11	$0.6
3% (Average)	$46	$2.6
2.5% (Average)	$73	$4.2
3% (95th percentile)	$140	$8.1

[a] All estimates have been rounded to two significant digits. The SCC values are dollar-year and emissions-year specific. SCC values represent only a partial accounting of climate impacts.

[b] The tonnes of CO_2 emission reductions in this table reflect the anticipated emission increases associated with the energy disbenefits described in section 6.3.

6.3 Energy Disbenefits

In this section, we provide an estimate of the energy disbenefits associated with the increased emissions from additional energy usage.[25] We estimate that electricity usage associated with operation of the control devices would increase by 123 GWh/yr nationwide.[26] This electricity usage is anticipated to increase emissions of pollutants from electric utility boilers (EGU boilers) that supply electricity to the non-EGU boiler facilities by 104,381 tonnes CO_2. In the calculation of CO_2 benefits, we have already subtracted these CO_2 emission increases associated with increased electricity usage from the CO_2 emission reductions associated with the regulatory requirements in the benefits shown in Table 6-6.

[24] It is possible that other benefits or costs of proposed regulations unrelated to CO_2 emissions will be discounted at rates that differ from those used to develop the SCC estimates.

[25] As we use the term "energy disbenefits" in this analysis, we are not referring to the cost of purchasing additional electricity or fuel, which are captured within the cost estimates. We use the term to refer to the increase in emissions associated with additional energy use.

[26] See *Impact Estimates for Fuel Gas Combustion Device and Flare Regulatory Options for Amendments to the Petroleum Refinery NSPS*, in Docket ID No. EPA-HQ-OAR-2007-0011.

6.4 Total Monetized Benefits

The total monetized benefits of this rulemaking include both the PM-related health benefits as well as the CO_2-related climate benefits. We estimate the total monetized benefits to be $260 million to $580 million at a 3% discount rate and $240 million to $520 million at a 7% discount rate. All estimates are in 2006$ for the year 2017. Figures 6-3 and 6-4 provide a visual representation of the breakdown of total monetized benefits by pollutant and requirement, respectively.

Alternatively, if no refineries install flare gas recovery systems, EPA estimates the monetized benefits of $190 to $460 million and $170 to $410 million at discount rates of 3% and 7% respectively. For small flares only, we estimate the monetized benefits are $170 million to $410 million (3% discount rate) and $150 million to $370 million (7% discount rate for health benefits and 3% discount rate for climate benefits). For large flares, we estimate the monetized benefits are $93 million to $160 million (3% discount rate) and $88 million to $150 million (7% discount rate for health benefits and 3-percent discount rate for climate benefits). All estimates are in 2006 dollars for the year 2017.

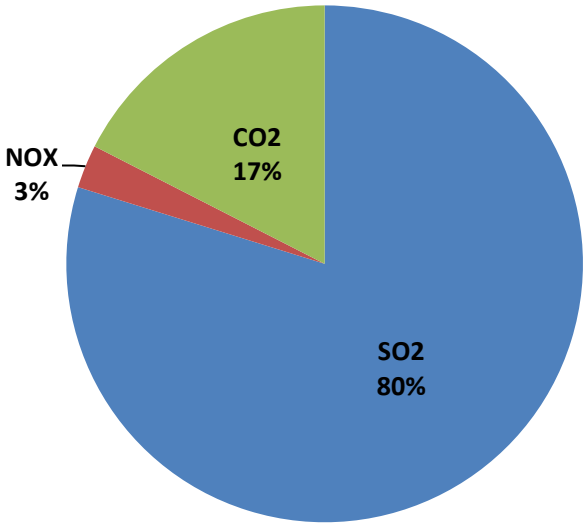


Figure 6-3: Breakdown of Monetized Benefits for Final Petroleum Refineries NSPS Reconsideration by Pollutant

* This chart uses the results based on Pope et al. (2002) and a 3% discount rate as an example.

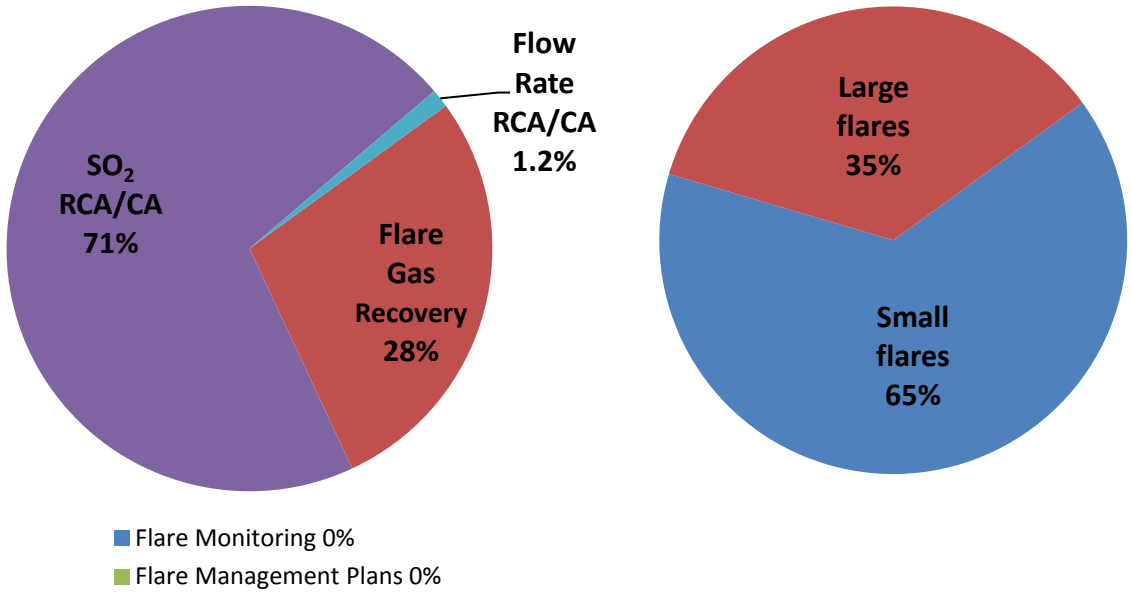


Figure 6-4: Breakdown of Monetized Benefits for Final Petroleum Refineries NSPS Reconsideration by Requirement and Flare Size

6.5 Unquantified Benefits

The monetized benefits estimated in this RIA only reflect a subset of benefits attributable to the health effect reductions associated with ambient fine particles. Data, time, and resource limitations prevented EPA from quantifying the impacts to, or monetizing the benefits from several important benefit categories, including benefits from reducing direct exposure to SO_2 and NOx, ozone exposure, ecosystem effects, and visibility impairment. NO_x and SO_2 emissions also contribute to adverse welfare effects, including acidic deposition in aquatic and terrestrial ecosystems and visibility impairment.

6.5.1 Additional SO_2 and NO_2 Benefits

In addition to being a precursor to $PM_{2.5}$, SO_2 and NO_x emissions are also associated with a variety of respiratory health effects. Unfortunately, we were unable to estimate the health benefits associated with reduced SO_2 and NO_2 exposure in this analysis because we do not have air quality modeling data available. Therefore, this analysis only quantifies and monetizes the $PM_{2.5}$ benefits associated with the reductions in SO_2 and NO_2 emissions.

Following an extensive evaluation of health evidence from epidemiologic and laboratory studies, the U.S. EPA has concluded that there is a causal relationship between respiratory health

effects and short-term exposure to SO_2 (U.S. EPA, 2008b). According to summary of the ISA in EPA's risk and exposure assessment (REA) for the SO_2 NAAQS, "the immediate effect of SO_2 on the respiratory system in humans is bronchoconstriction" (U.S. EPA, 2009b). Asthmatics are more sensitive to the effects of SO_2 likely resulting from preexisting inflammation associated with this disease. A clear concentration-response relationship has been demonstrated in laboratory studies following exposures to SO_2 at concentrations between 20 and 100 ppb, both in terms of increasing severity of effect and percentage of asthmatics adversely affected. Based on our review of this information, we identified four short-term morbidity endpoints that the SO_2 ISA identified as a "causal relationship": asthma exacerbation, respiratory-related emergency department visits, and respiratory-related hospitalizations. The differing evidence and associated strength of the evidence for these different effects is described in detail in the SO_2 ISA. The SO_2 ISA also concluded that the relationship between short-term SO_2 exposure and premature mortality was "suggestive of a causal relationship" because it is difficult to attribute the mortality risk effects to SO_2 alone. Although the SO_2 ISA stated that studies are generally consistent in reporting a relationship between SO_2 exposure and mortality, there was a lack of robustness of the observed associations to adjustment for pollutants.

Following an extensive evaluation of health evidence from epidemiologic and laboratory studies, the Integrated Science Assessment (ISA) for Nitrogen Dioxide concluded that there is a likely causal relationship between respiratory health effects and short-term exposure to NO_2 (U.S. EPA, 2008c). Persons with preexisting respiratory disease, children, and older adults may be more susceptible to the effects of NO_2 exposure. Based on our review of this information, we identified four short-term morbidity endpoints that the NO_2 ISA identified as a "likely causal relationship": asthma exacerbation, respiratory-related emergency department visits, and respiratory-related hospitalizations. The differing evidence and associated strength of the evidence for these different effects is described in detail in the NO_2 ISA. The NO_2 ISA also concluded that the relationship between short-term NO_2 exposure and premature mortality was "suggestive but not sufficient to infer a causal relationship" because it is difficult to attribute the mortality risk effects to NO_2 alone. Although the NO_2 ISA stated that studies consistently reported a relationship between NO_2 exposure and mortality, the effect was generally smaller than that for other pollutants such as PM.

SO_2 and NOx emissions also contribute to a variety of adverse welfare effects, including acidic deposition, visibility impairment, nutrient enrichment (NOx only) and enhanced mercury methylation (SO_2 only). Deposition of sulfur and nitrogen causes acidification, which can cause a loss of biodiversity of fishes, zooplankton, and macro invertebrates in aquatic ecosystems, as

well as a decline in sensitive tree species, such as red spruce (*Picea rubens*) and sugar maple (*Acer saccharum*) in terrestrial ecosystems. In the northeastern United States, the surface waters affected by acidification are a source of food for some recreational and subsistence fishermen and for other consumers and support several cultural services, including aesthetic and educational services and recreational fishing. Biological effects of acidification in terrestrial ecosystems are generally linked to aluminum toxicity, which can cause reduced root growth, which restricts the ability of the plant to take up water and nutrients. These direct effects can, in turn, increase the sensitivity of these plants to stresses, such as droughts, cold temperatures, insect pests, and disease leading to increased mortality of canopy trees. Terrestrial acidification affects several important ecological services, including declines in habitat for threatened and endangered species (cultural), declines in forest aesthetics (cultural), declines in forest productivity (provisioning), and increases in forest soil erosion and reductions in water retention (cultural and regulating). (U.S. EPA, 2008d)

Deposition of nitrogen is also associated with aquatic and terrestrial nutrient enrichment. In estuarine waters, excess nutrient enrichment can lead to eutrophication. Eutrophication of estuaries can disrupt an important source of food production, particularly fish and shellfish production, and a variety of cultural ecosystem services, including water-based recreational and aesthetic services. Terrestrial nutrient enrichment is associated with changes in the types and number of species and biodiversity in terrestrial systems. Excessive nitrogen deposition upsets the balance between native and nonnative plants, changing the ability of an area to support biodiversity. When the composition of species changes, then fire frequency and intensity can also change, as nonnative grasses fuel more frequent and more intense wildfires. (U.S. EPA, 2008d)

Mercury is a highly neurotoxic contaminant that enters the food web as a methylated compound, methylmercury (U.S. EPA, 2008d). The contaminant is concentrated in higher trophic levels, including fish eaten by humans. Experimental evidence has established that only inconsequential amounts of methylmercury can be produced in the absence of sulfate (U.S. EPA, 2008d). Current evidence indicates that in watersheds where mercury is present, increased sulfate deposition very likely results in methylmercury accumulation in fish (Drevnick et al., 2007; Munthe et al, 2007). The NOx/SO_x Ecological ISA concluded that evidence is sufficient to infer a casual relationship between sulfur deposition and increased mercury methylation in wetlands and aquatic environments (U.S. EPA, 2008d).

Reducing SO_2 and NO_x emissions and the secondary formation of $PM_{2.5}$ would improve the level of visibility throughout the United States. Fine particles with significant light-

extinction efficiencies include sulfates, nitrates, organic carbon, elemental carbon, and soil (Sisler, 1996). These 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. In fact, particulate sulfate is the largest contributor to regional haze in the eastern U.S. (i.e., 40% or more annually and 75% during summer). In the western U.S., particulate sulfate contributes to 20-50% of regional haze (U.S. EPA, 2009c). 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.

6.5.2 Ozone Benefits

In the presence of sunlight, NOx and VOCs can undergo a chemical reaction in the atmosphere to form ozone. Reducing ambient ozone concentrations is associated with significant human health benefits, including mortality and respiratory morbidity (U.S. EPA, 2008a). Epidemiological researchers have associated ozone exposure with adverse health effects in numerous toxicological, clinical and epidemiological studies (U.S. EPA, 2006c). These health effects include respiratory morbidity such as fewer asthma attacks, hospital and ER visits, school loss days, as well as premature mortality.

6.5.3 Visibility Impairment

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, 2006; U.S. EPA, 2011a; U.S. EPA, 2011b) 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.

6.6 Characterization of Uncertainty in the Monetized Benefits

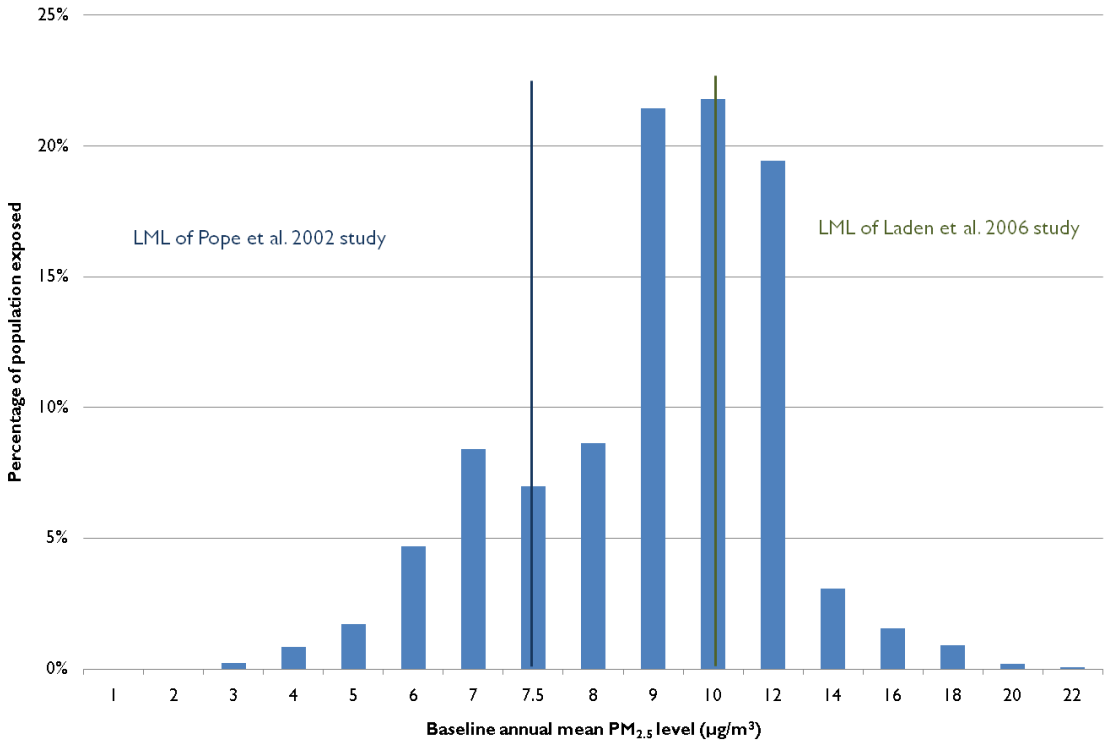
In any complex analysis, there are likely to be many sources of uncertainty. Many inputs are used to derive the final estimate of economic benefits, including emission inventories, air quality models (with their associated parameters and inputs), epidemiological estimates of concentration-response (C-R) functions, estimates of values, population estimates, income estimates, and estimates of the future state of the world (i.e., regulations, technology, and human behavior). For some parameters or inputs it may be possible to provide a statistical representation of the underlying uncertainty distribution. For other parameters or inputs, the necessary information is not available. As discussed in the $PM_{2.5}$ NAAQS RIA (Table 5.5) (U.S. EPA, 2006), there are a variety of uncertainties associated with these PM benefits. Therefore, the estimates of annual benefits should be viewed as representative of the magnitude of benefits expected, rather than the actual benefits that would occur every year.

It is important to note that the monetized benefit-per-ton estimates used here reflect specific geographic patterns of emissions reductions and specific air quality and benefits modeling assumptions. For example, these estimates do not reflect local variability in population density, meteorology, exposure, baseline health incidence rates, or other local factors. Use of these $/ton values to estimate benefits associated with different emission control programs (e.g., for reducing emissions from large stationary sources like EGUs) may lead to higher or lower benefit estimates than if benefits were calculated based on direct air quality modeling. Great care should be taken in applying these estimates to emission reductions occurring in any specific location, as these are all based on national or broad regional emission reduction programs and therefore represent average benefits-per-ton over the entire United States. The benefits-per-ton for emission reductions in specific locations may be very different than the estimates presented here.

$PM_{2.5}$ mortality benefits are the largest benefit category that we monetized in this analysis. To better characterize the uncertainty associated with mortality impacts that are estimated to occur in areas with low baseline levels of $PM_{2.5}$, we included the LML assessment. For this analysis, policy-specific air quality data is not available due to time or resource limitations, thus we are unable to estimate the percentage of premature mortality associated with this specific rule's emission reductions at each $PM_{2.5}$ level. As a surrogate measure of mortality impacts, we provide the percentage of the population exposed at each $PM_{2.5}$ level using the source apportionment modeling used to calculate the benefit-per-ton estimates for this sector. A very large proportion of the population is exposed at or above the lowest LML of the cohort studies (Figures 6-5 and 6-6), increasing our confidence in the PM mortality analysis. Figure 6-5

shows a bar chart of the percentage of the population exposed to various air quality levels in the pre- and post-policy policy. Figure 6-6 shows a cumulative distribution function of the same data. Both figures identify the LML for each of the major cohort studies. As the policy shifts the distribution of air quality levels, fewer people are exposed to $PM_{2.5}$ levels at or above the LML. Using the Pope et al. (2002) study, the 77% of the population is exposed to annual mean $PM_{2.5}$ levels at or above the LML of 7.5 $\mu g/m^3$. Using the Laden et al. (2006) study, 25% of the population is exposed above the LML of 10 $\mu g/m^3$. As we model avoided premature deaths among populations exposed to levels of $PM_{2.5}$, we have lower confidence in levels below the LML for each study. It is important to emphasize that we have high confidence in $PM_{2.5}$-related effects down to the lowest LML of the major cohort studies. Just because we have greater confidence in the benefits above the LML, this does not mean that we have no confidence that benefits occur below the LML.

A large fraction of the baseline exposure occurs below the level of the National Ambient Air Quality Standard (NAAQS) for annual $PM_{2.5}$ at 15 $\mu g/m^3$, which was set in 2006. It is important to emphasize that NAAQS are not set at a level of zero risk. Instead, the NAAQS reflect the level determined by the Administrator to be protective of public health within an adequate margin of safety, taking into consideration effects on susceptible populations. While benefits occurring below the standard may be less certain than those occurring above the standard, EPA considers them to be legitimate components of the total benefits estimate.

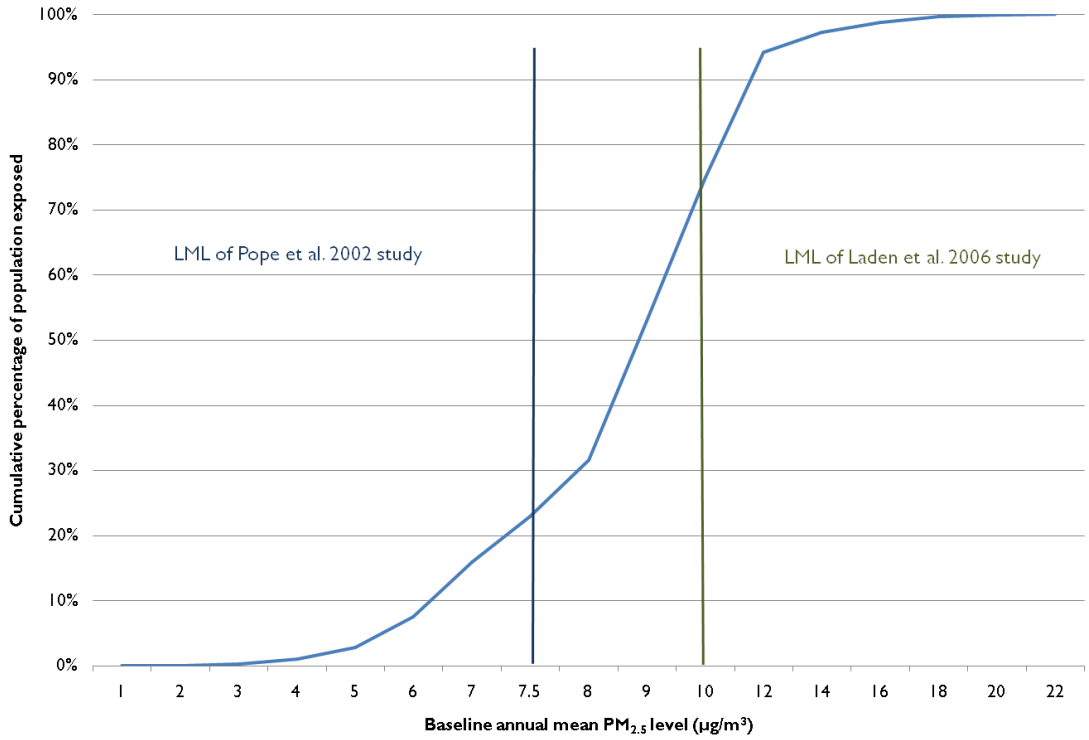


Among the populations exposed to $PM_{2.5}$ in the baseline:

77% are exposed to $PM_{2.5}$ levels at or above the LML of the Pope et al. (2002) study

25% are exposed to $PM_{2.5}$ levels at or above the LML of the Laden et al. (2006) study

Figure 6-5. Percentage of Adult Population by Annual Mean $PM_{2.5}$ Exposure in the Baseline



Among the populations exposed to $PM_{2.5}$ in the baseline:
77% are exposed to $PM_{2.5}$ levels at or above the LML of the Pope et al. (2002) study
25% are exposed to $PM_{2.5}$ levels at or above the LML of the Laden et al. (2006) study

Figure 6-6. Cumulative Distribution of Adult Population by Annual Mean $PM_{2.5}$ Exposure in the Baseline

Above we present the estimates of the total benefits, based on our interpretation of the best available scientific literature and methods and supported by the SAB-HES and the NAS (NRC, 2002). The benefits estimates are subject to a number of assumptions and uncertainties. For example, for key assumptions underlying the estimates for premature mortality, which typically account for at least 90% of the total benefits, we were able to quantify include the following:

1. $PM_{2.5}$ benefits were derived through benefit per-ton estimates, which do not reflect local variability in population density, meteorology, exposure, baseline health incidence rates, or other local factors that might lead to an over-estimate or under-estimate of the actual benefits of controlling directly emitted fine particulates. We do not have data on the specific location of the air quality changes associated with this rulemaking; as such, it is not feasible to estimate the proportion of benefits occurring in different locations, such as designated nonattainment areas. In addition, the benefit-per-ton estimates are based on emissions from existing sources. To the extent

that the geographic distribution of the emissions reductions for this rule are different than the modeled emissions, the benefits may be underestimated or overestimated. In general, there is inherently more uncertainty for new sources, which may not be included in the emissions inventory, than existing sources.

2. We assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality. This is an important assumption, because $PM_{2.5}$ produced via transported precursors emitted from EGUs may differ significantly from direct $PM_{2.5}$ released from diesel engines and other industrial sources, but no clear scientific grounds exist for supporting differential effects estimates by particle type.
3. We assume that the health impact function for fine particles is linear down to the lowest air quality levels modeled in this analysis. Thus, the estimates include health benefits from reducing fine particles in areas with varied concentrations of $PM_{2.5,}$ including both regions that are in attainment with fine particle standard and those that do not meet the standard down to the lowest modeled concentrations.
4. To characterize the uncertainty in the relationship between $PM_{2.5}$ and premature mortality (which typically accounts for 85% to 95% of total monetized benefits), we include a set of twelve estimates based on results of the expert elicitation study in addition to our core estimates. Even these multiple characterizations omit the uncertainty in air quality estimates, baseline incidence rates, populations exposed and transferability of the effect estimate to diverse locations. As a result, the reported confidence intervals and range of estimates give an incomplete picture about the overall uncertainty in the $PM_{2.5}$ estimates. This information should be interpreted within the context of the larger uncertainty surrounding the entire analysis. For more information on the uncertainties associated with $PM_{2.5}$ benefits, please consult the $PM_{2.5}$ NAAQS RIA (Table 5.5).

This RIA does not include the type of detailed uncertainty assessment found in the PM NAAQS RIA because we lack the necessary air quality input and monitoring data to run the benefits model. In addition, we have not conducted any air quality modeling for this rule. Moreover, it was not possible to develop benefit-per-ton metrics and associated estimates of uncertainty using the benefits estimates from the PM RIA because of the significant differences between the sources affected in that rule and those regulated here. However, the results of the Monte Carlo analyses of the health and welfare benefits presented in Chapter 5 of the PM RIA can provide some evidence of the uncertainty surrounding the benefits results presented in this analysis.

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7 COMPARISON OF BENEFITS AND COSTS

EPA estimates the range of benefits of this reconsideration to be $260 million to $580 million at a 3% discount rate and $240 million to $520 million at a 7% discount rate in 2017. The annualized costs are a cost savings of $79 million at a 7% interest rate. Thus, net benefits are $340 million to $660 million at a 3% discount rate for the benefits and $320 million to $600 million at a 7% discount rate. All estimates are in 2006$.

Table 7-1 provides details, by flare size, of the monetized benefits and Table 7-2 shows a summary of the monetized benefits, social costs, and net benefits. Figure 7-1 shows the full range of net benefits estimates (i.e., benefits minus annualized costs) utilizing the 14 different $PM_{2.5}$ mortality functions at the 3% discount rate, and Figure 7-2 shows this information at a 7% discount rate. EPA believes that the benefits of this rule are likely to exceed the costs by a substantial margin even when taking into account uncertainties in the cost and benefit estimates.

Alternatively, if no refineries install flare gas recovery systems, EPA estimates the costs would be $10.7 million with monetized benefits of $190 to $460 million and $170 to $410 million at a discount rates of 3% and 7% respectively. Thus, net benefits without flare gas recovery systems would be $180 million to $450 million and $160 million to $400 million, at 3% and 7% discount rates, respectively. All estimates are in 2006 dollars for the year 2017.

For small flares, we estimate the monetized benefits are $170 million to $410 million (3-percent discount rate) and $150 million to $370 million (7% discount rate for health benefits and 3% discount rate for climate benefits). For large flares, we estimate the monetized benefits are $93 million to $160 million (3% discount rate) and $88 million to $150 million (7% discount rate for health benefits and 3-percent discount rate for climate benefits). All estimates are in 2006 dollars for the year 2017.

Table 7-1. National Incremental Cost Impacts, Emission Reductions, and Cost Effectiveness for Petroleum Refinery Flares Subject to Amended Standards Under 40 CFR part 60, subpart Ja (Fifth Year After Effective Date of Final Rule Amendments)[1]

	Subpart Ja Requirements	Total capital cost (millions)	Total annual cost without credit (millions/yr)	Natural gas offset/ product recovery credit (millions)	Total annual cost (millions/yr)	Annual emission reductions (tons SO_2/yr)	Annual emission reductions (tons NO_X/yr)	Annual emission reductions (tons VOC/yr)	Cost effective-ness ($/ton emissions reduced)	Annual emission reductions (metric tons CO_2/yr)[2]	Monetized Benefits (millions, 3% discount rate for health and climate benefits)			Monetized Benefits (millions, 3% discount rate for health and 7% for climate benefits)		
Small Flares	Flare Monitoring	$72	$12	$0	$12	0	0	0		0	$0	to	$0	$0	to	$0
	Flare gas recovery	$0	$0	$0	$0	0	0	0		0	$0	to	$0	$0	to	$0
	Flare Management	$0	$0.79	$0	$0.79	0	0	270	$2,900	0	$0	to	$0	$0	to	$0
	SO2 RCA/CA	$0	$1.9	$0	$1.9	2,600	0	0	$760	0	$170	to	$410	$150	to	$370
	Flowrate RCA/CA	$0	$0.90	-$6.7	-$5.8	3.4	50	390	-$13,000	98,000	$2.9	to	$3.7	$2.9	to	$3.6
	Total	**$72**	**$16**	**-$6.7**	**$9.0**	**2,600**	**50**	**660**	**$2,700**	**98,000**	**$170**	**to**	**$410**	**$150**	**to**	**$370**
Large Flares	Flare Monitoring	$12	$2.0	$0	$2.0	0	0	0		0	$0	to	$0	$0	to	$0
	Flare gas recovery	$380	$78	-$170	-$90	380	1,100	2,700	-$22,000	1,800,000	$74	to	$120	$71	to	$110
	Flare Management	$0	$0.088	$0	$0.088	0	0	30	$2,900	0	$0	to	$0	$0	to	$0
	SO2 RCA/CA	$0	$0.22	$0	$0.22	290	0	0	$760	0	$18	to	$45	$17	to	$41
	Flowrate RCA/CA	$0	$0.10	-$0.74	-$0.64	0	6	43	-$13,000	11,000	$0	to	$0	$0	to	$0
	Total	**$390**	**$81**	**-$170**	**-$88**	**660**	**1,100**	**2,800**	**-$20,000**	**1,800,000**	**$93**	**to**	**$160**	**$88**	**to**	**$150**
All Flares	Flare Monitoring	$84	$14	$0	$14	0	0	0		0	$0	to	$0	$0	to	$0
	Flare gas recovery	$380	$78	-$170	-$90	380	1,100	2,700	-$22,000	1,800,000	$74	to	$120	$71	to	$110
	Flare Management	$0	$0.88	$0	$0.88	0	0	300	$2,900	0	$0	to	$0	$0	to	$0
	SO2 RCA/CA	$0	$2.2	$0	$2.2	2,900	0	0	$760	0	$180	to	$450	$170	to	$410
	Flowrate RCA/CA	$0	$1.00	-$7.4	-$6.4	3.4	56	430	-$13,000	110,000	$3.2	to	$4.0	$3.1	to	$3.9
	Total	**$460**	**$96**	**-$180**	**-$79**	**3,200**	**1,100**	**3,400**	**-$10,000**	**1,900,000**	**$260**	**to**	**$580**	**$240**	**to**	**$520**

[1]All estimates are for the implementation year (2017), and are rounded to two significant figures.
[2] The emission reductions of CO_2 reflect the anticipated emission increases associated with the energy disbenefits from additional electricity consumption.

Table 7-2. Summary of the Monetized Benefits, Social Costs, and Net Benefits for the Final Petroleum Refineries NSPS in 2017 (millions of 2006$)[1]

	3% Discount Rate	7% Discount Rate
Total Monetized Benefits[2]	$260 to $580	$240 to $520
Total Compliance Costs[3]	-$79	-$79
Net Benefits	$340 to $660	$320 to $600
Non-monetized Benefits	Health effects from ozone, SO_2, NO_2 exposure Health effects from $PM_{2.5}$ exposure from VOCs Ecosystem effects Visibility impairment	

[1]All estimates are for the implementation year (2017), and are rounded to two significant figures.

[2] The total monetized benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of $PM_{2.5}$ precursors such as NOx and SO_2 as well as CO_2 benefits. It is important to note that the monetized benefits do not include the reduced health effects from direct exposure to SO_2 and NOx, ozone exposure, ecosystem effects, or visibility impairment. Human health benefits are shown as a range from Pope et al. (2002) to Laden et al. (2006). These models assume 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 effects estimates by particle type. The net present value of reduced CO_2 emissions is calculated differently than other benefits. This table includes monetized climate benefits using the global average social cost of carbon (SCC) estimated at a 3 percent discount rate because the interagency workgroup deemed the SCC estimate at a 3 percent discount rate to be the central value.

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

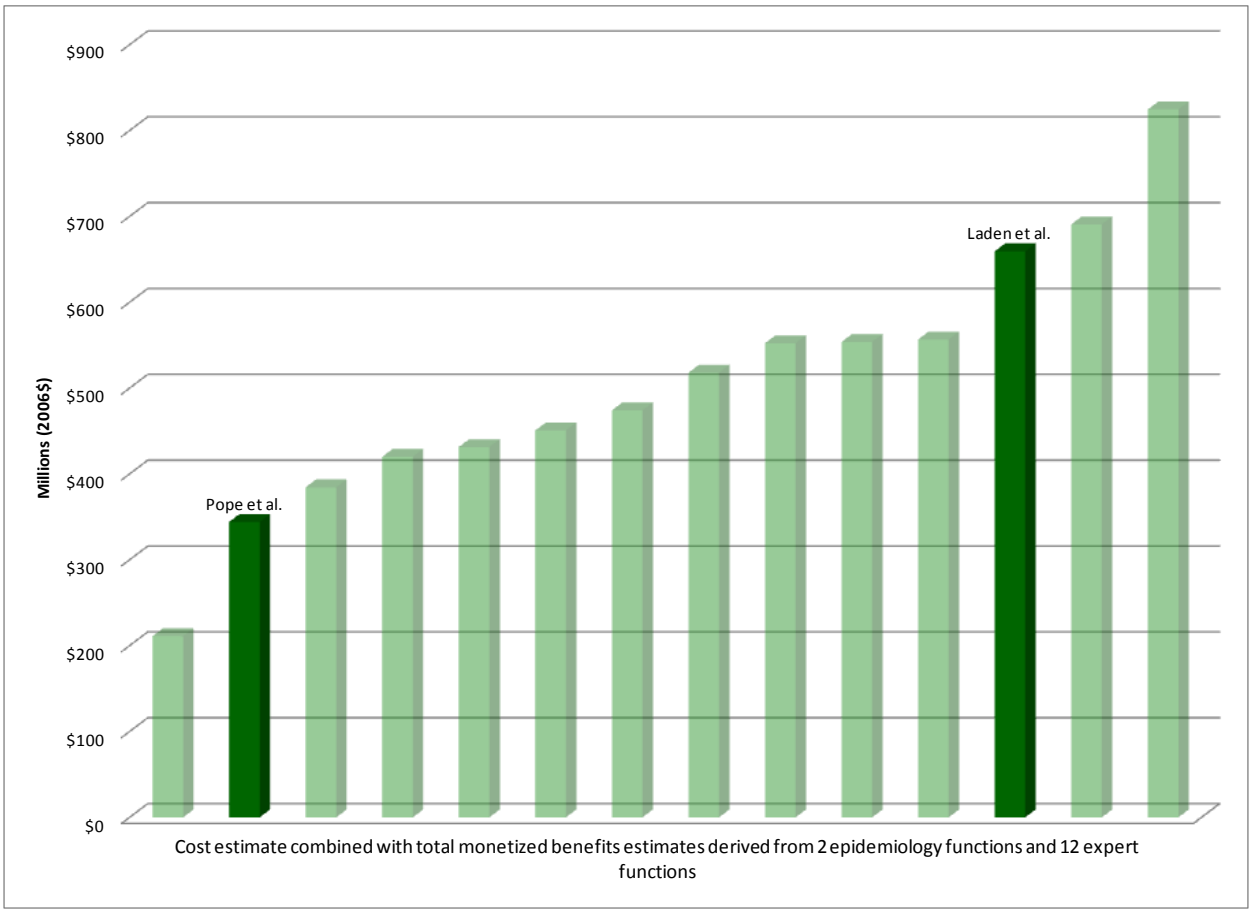

Figure 7-1. Net Benefits for Final Petroleum Refineries NSPS Reconsideration at 3% discount rate*

*Net Benefits are quantified in terms of $PM_{2.5}$ and CO_2 benefits at a 3% discount rate for 2017. This graph shows 14 benefits estimates combined with the cost estimate. All fine particles are assumed to have equivalent health effects. The monetized benefits incorporate the conversion from precursor emissions to ambient fine particles.

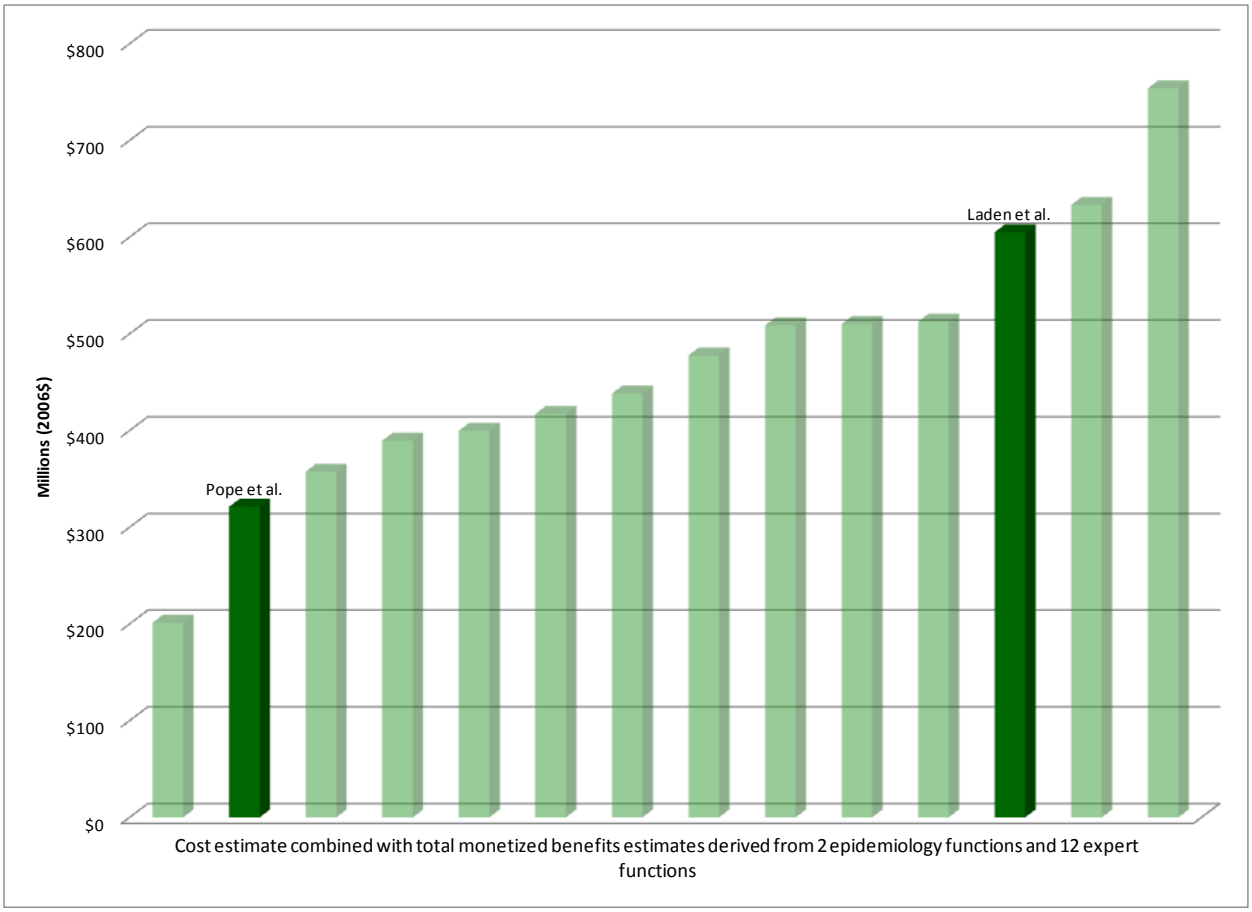

Figure 7-2. Net Benefits for Final Petroleum Refineries NSPS Reconsideration at 7% discount rate*

*Net Benefits are quantified in terms of $PM_{2.5}$ benefits at a 7% discount rate and CO_2 benefits at a 3% discount rate for 2017. This graph shows 14 benefits estimates combined with the cost estimate. All fine particles are assumed to have equivalent health effects. The monetized benefits incorporate the conversion from precursor emissions to ambient fine particles.

APPENDIX A
PARENT COMPANY INFORMATION FOR PETROLEUM REFINERIES

Table A-1. Parent Company Information for Petroleum Refineries

Facility Name	City	State	Capacity (bbl/cd)	Parent Company Name	Parent Company Sales	Parent Company Employment
AGE Refining Inc	San Antonio	TX	14,021	AGE Refining, Inc.	65.00	124
Alon Bakersfield Operating Inc	Bakersfield	CA		Alon Israel Oil Company LTD	7,283.06	12,000
Alon Refining Krotz Springs Inc	Krotz Springs	LA	80,000	Alon Israel Oil Company LTD	7,283.06	12,000
Alon USA Energy Inc.	Big Spring	TX	67,000	Alon Israel Oil Company LTD	7,283.06	12,000
American Refining Group Inc	Bradford	PA	10,000	American Refining Group, Inc.	737.19	323
Big West Oil Co.	North Salt Lake	UT	29,400	Flying J Oil & Gas Inc.	1,719.00	15,000
BP Exploration Alaska Inc	Prudhoe Bay	AK	12,780	BP PLC	297,107.00	12,633
BP Products North America Inc	Whiting	IN	405,000	BP PLC	297,107.00	12,633
BP Products North America Inc	Texas City	TX	406,570	BP PLC	297,107.00	12,633
BP West Coast Products LLC	Los Angeles	CA	253,000	BP PLC	297,107.00	12,633
BP West Coast Products LLC	Ferndale	WA	225,000	BP PLC	297,107.00	12,633
BP-Husky Refining LLC	Toledo	OH	131,400	BP PLC	297,107.00	12,633
Calcasieu Refining Co.	Lake Charles	LA	78,000	Calcasieu Refining Company	291.74	92
Calumet Lubricants Co LP	Cotton Valley	LA	13,020	Calumet Specialty Products Partners, L.P.	2,190.75	654
Calumet Lubricants Co LP	Princeton	LA	8,300	Calumet Specialty Products Partners, L.P.	2,190.75	654
Calumet Shreveport LLC	Shreveport	LA	57,000	Calumet Specialty Products Partners, L.P.	2,190.75	654
Cenex Harvest States	Laurel	MT	59,600	CHS, Inc.	23.30	287
Chalmette Refining LLC	Chalmette	LA	192,500	ExxonMobil Corp.	383,221.00	83,600
Chevron USA Inc.	Perth Amboy	NJ	80,000	Chevron Corporation	204,928.00	58,267
Chevron USA Inc.	Salt Lake City	UT	45,000	Chevron Corporation	204,928.00	58,267
Chevron USA Inc.	Pascagoula	MS	330,000	Chevron Corporation	204,928.00	58,267
Chevron USA Inc.	El Segundo	CA	273,000	Chevron Corporation	204,928.00	58,267
Chevron USA Inc.	Richmond	CA	245,271	Chevron Corporation	204,928.00	58,267
Chevron USA Inc.	Honolulu	HI	54,000	Chevron Corporation	204,928.00	58,267
Citgo	Corpus Christi	TX	163,000	CITGO Petroleum Corporation	475.80	3,506
Citgo Petroleum Corp.	Lake Charles	LA	427,800	CITGO Petroleum Corporation	475.80	3,506
Coffeyville Resources Rfg & Mktg LLC	Coffeyville	KS	115,700	CVR Energy, Inc.	4,079.77	371
ConocoPhillips	Sweeny	TX	247,000	ConocoPhillips	198,655.00	29,700
ConocoPhillips	Linden	NJ	238,000	ConocoPhillips	198,655.00	29,700
ConocoPhillips	Wilmington	CA	139,000	ConocoPhillips	198,655.00	29,700
ConocoPhillips	SF—Rodeo	CA	120,200	ConocoPhillips	198,655.00	29,700
ConocoPhillips	Belle Chasse	LA	247,000	ConocoPhillips	198,655.00	29,700
ConocoPhillips Alaska Inc	Prudhoe Bay	AK	15,000	ConocoPhillips	198,655.00	29,700
ConocoPhillips Co	Trainer	PA	185,000	ConocoPhillips	198,655.00	29,700

(continued)

Table A-1. Parent Company Information for Petroleum Refineries (continued)

Facility Name	City	State	Capacity (bbl/cd)	Parent Company Name	Parent Company Sales	Parent Company Employment
ConocoPhillips Company	Westlake	LA	239,400	ConocoPhillips	198,655.00	29,700
ConocoPhillips Company	Ponca City	OK	198,400	ConocoPhillips	198,655.00	29,700
ConocoPhillips Company	Billings	MT	58,000	ConocoPhillips	198,655.00	29,700
ConocoPhillips Company	Ferndale	WA	100,000	ConocoPhillips	198,655.00	29,700
Countrymark Cooperative, Inc.	Mt. Vernon	IN	26,500	Countrymark Cooperative	862.97	425
Deer Park Refining LTD Partnership	Deer Park	TX	327,000	Royal Dutch Shell, PLC	378,152.00	93,000
Delaware City Refining Co LLC	Delaware City	DE	182,200	PBF Holdings LLC	Not Listed	Not Listed
Delek Refining Ltd	Tyler	TX	60,000	Delek US Holdings, Inc.	3,755.60	3,296
Equistar Chemicals LP	Channelview	TX		Lyondell Basell Industries N.V.	27,684.00	14,000
Ergon Refining Inc.	Vicksburg	MS	23,000	Ergon, Inc.	3,830.00	1,625
Ergon West Virginia Inc.	Newell	WV	20,000	Ergon, Inc.	3,830.00	1,625
Excel Paralubes	Westlake	LA		Koch Industries Inc	9,182.50	62,544
ExxonMobil Corp.	Beaumont	TX	344,500	ExxonMobil Corp.	383,221.00	83,600
ExxonMobil Corp.	Torrance	CA	149,500	ExxonMobil Corp.	383,221.00	83,600
ExxonMobil Oil Corp	Baytown	TX	560,640	ExxonMobil Corp.	383,221.00	83,600
ExxonMobil Refining & Supply Co	Baton Rouge	LA	502,000	ExxonMobil Corp.	383,221.00	83,600
ExxonMobil Refining & Supply Co	Billings	MT	60,000	ExxonMobil Corp.	383,221.00	83,600
ExxonMobil Refining & Supply Co	Joliet	IL	238,600	ExxonMobil Corp.	383,221.00	83,600
Flint Hills Resources	Corpus Christi	TX	290,078	Koch Industries Inc	9,182.50	62,544
Flint Hills Resources	North Pole	AK	219,500	Koch Industries Inc	9,182.50	62,544
Flint Hills Resources	Saint Paul	MN	262,000	Koch Industries Inc	9,182.50	62,544
Foreland Refining Co.	Ely	NV	2,000	Foreland Refining Corp.	12.55	27
Frontier El Dorado Refining Co	El Dorado	KS	138,000	Frontier Oil Corp.	5,884.91	723
Frontier Refining Inc	Cheyenne	WY	47,000	Frontier Oil Corp.	5,884.91	723
Garco Energy LLC	Douglas	WY	3,600	Garco Energy	11.44	16
Goodway Refining LLC	Atmore	AL	4,100	Goodway Refining, LLC	2.00	17
Greka Energy	Santa Maria	CA	9,500	Santa Maria Refining Company	2.80	47
Gulf Atlantic Operations	Mobile Bay	AL	20,000	Gulf Atlantic Operations LLC	76.99	32
Hess Corporation	Port Reading	NJ		Hess Corporation	34,613.00	13,800
Holly Refining & Marketing Co	Woods Cross	UT	25,050	Holly Corporation	8,323.00	1,321
Holly Refining & Marketing Co	Tulsa East	OK	70,300	Holly Corporation	8,323.00	1,321
Holly Refining & Marketing Co	Tulsa West	OK	85,000	Holly Corporation	8,323.00	1,321
Houston Refining LP	Houston	TX	280,390	Lyondell Basell Industries N.V.	27,684.00	14,000
Hunt Refining Co.	Tuscaloosa	AL	36,000	Hunt Refining Co.	4,871.00	346
Hunt Southland Refining Co	Sandersville	MS	11,000	Hunt Refining Co.	4,871.00	1,100

(continued)

Table A-1. Parent Company Information for Petroleum Refineries (continued)

Facility Name	City	State	Capacity (bbl/cd)	Parent Company Name	Parent Company Sales	Parent Company Employment
Kern Oil & Refining Co.	Bakersfield	CA	26,000	Kern Oil & Refining Co.	282.00	105
Lima Refining Company	Lima	OH	155,000	Husky Energy, Inc.	18,174.36	4,491
Lion Oil Co.	El Dorado	AR	75,000	Lion Oil Co.	169.60	350
Little America Refining Co.	Evansville	WY	24,500	Sinclair Co.'s	7,753.46	7,000
Lunday-Thagard Co.	South Gate	CA	8,500	World Oil Marketing Co.	35.40	65
Marathon Petroleum Co. LLC	Robinson	IL	206,000	Marathon Oil Corp	73,621.00	29,677
Marathon Petroleum Co. LLC	Catlettsburg	KY	212,000	Marathon Oil Corp	73,621.00	29,677
Marathon Petroleum Co. LLC	Detroit	MI	106,000	Marathon Oil Corp	73,621.00	29,677
Marathon Petroleum Co. LLC	Canton	OH	78,000	Marathon Oil Corp	73,621.00	29,677
Marathon Petroleum Co. LLC	Texas City	TX	76,000	Marathon Oil Corp	73,621.00	29,677
Marathon Petroleum Co. LLC	Garyville	LA	464,000	Marathon Oil Corp	73,621.00	29,677
Martin Midstream Partners LP	Smackover	AR	7,500	Cross Oil Refining & Marketing, Inc.	265.00	110
Montana Refining Co.	Great Falls	MT	10,000	Connacher Oil and Gas, Limited	574.19	265
Motiva Enterprises	Port Arthur	TX	285,000	Motiva Enterprises LLC	26,400.00	2,900
Motiva Enterprises LLC	Norco	LA	233,500	Motiva Enterprises LLC	26,400.00	2,900
Motiva Enterprises LLC	Convent	LA	235,000	Motiva Enterprises LLC	26,400.00	2,900
Murphy Oil USA Inc.	Superior	WI	34,300	Murphy Oil Corp	23,345.07	8,994
Murphy Oil USA Inc.	Meraux	LA	125,000	Murphy Oil Corp	23,345.07	8,994
National Cooperative Refinery Association	McPherson	KS	85,500	National Cooperative Refinery Association	2,810.30	612
Navajo Refining Co.	Artesia	NM	105,000	Holly Corporation	8,323.00	1,321
Nustar Asphalt Refining LLC	Paulsboro	NJ	70,000	NuStar Energy LP	4,403.06	1,492
Nustar Asphalt Refining LLC	Savannah	GA	28,000	NuStar Energy LP	4,403.06	1,492
Paramount Petroleum Co	Long Beach	CA	31,500	Alon Israel Oil Company LTD	7,283.06	12,000
Paramount Petroleum Corp.	Paramount	CA	53,000	Alon Israel Oil Company LTD	7,283.06	12,000
Pasadena Refining Systems Inc.	Pasadena	TX	100,000	Pasadena Refining	31.00	348
Paulsboro Refining Co LLC	Paulsboro	NJ	160,000	PBF Holding Company LLC	Not Listed	Not Listed
PDV Midwest Refining	Lemont	IL	167,000	Petróleos de Venezuela S.A. (PDVSA)	75.00	102,750
Pelican Refining Co. LLC	Lake Charles	LA		Pelican Refining Co LLC	4.00	33
Petro Star Inc.	North Pole	AK	19,700	Petro Star Inc.	887.00	400
Petro Star Inc.	Valdez	AK	55,000	Petro Star Inc.	887.00	400
Placid Refining Inc.	Port Allen	LA	57,000	Placid Refining	3,351.84	207
Premcor Refining Group Inc	Memphis	TN	180,000	Valero Energy	82,233.00	20,313

(continued)

Table A-1. Parent Company Information for Petroleum Refineries (continued)

Facility Name	City	State	Capacity (bbl/cd)	Parent Company Name	Parent Company Sales	Parent Company Employment
Premcor Refining Group Inc	Port Arthur	TX	292,000	Valero Energy	82,233.00	20,313
San Joaquin Refining Co., Inc.	Bakersfield	CA	15,000	San Joaquin Refining Co.	3.50	108
Shell Chemical LP	St. Rose	LA	55,000	Royal Dutch Shell, PLC	378,152.00	93,000
Shell Chemical LP	Saraland	AL	80,000	Royal Dutch Shell, PLC	378,152.00	93,000
Shell Oil Products US	Anacortes	WA	145,000	Royal Dutch Shell, PLC	378,152.00	93,000
Shell Oil Products US	Martinez	CA	156,400	Royal Dutch Shell, PLC	378,152.00	93,000
Silver Eagle Refining	Evanston	WY	3,000	Silver Eagle Refining Inc.	225.87	60
Silver Eagle Refining	Woods Cross	UT	10,250	Silver Eagle Refining Inc.	225.87	60
Sinclair Wyoming Refining Co	Sinclair	WY	74,000	Sinclair Co.'s	7,753.46	7,000
Somerset Energy Refinery LLC	Somerset	KY	5,500	Somerset Oil Inc.	16.90	11
South Hampton Resources Inc.	Silsbee	TX		Arabian American Development Co	139.11	145
St Paul Park Refining Co. LLC	Saint Paul	MN	74,000	Northern Tier Energy LLC	Not listed	Not Listed
Suncor Energy Inc.	Commerce City West	CO	67,000	Suncor Energy Inc.	34,398.09	12,978
Suncor Energy Inc.	Commerce City East	CO	36,000	Suncor Energy Inc.	34,398.09	12,978
Sunoco, Inc.	Marcus Hook	PA	178,000	Sunoco, Inc.	37,489.00	4,544
Sunoco, Inc.	Toledo	OH	160,000	Sunoco, Inc.	37,489.00	4,544
Sunoco, Inc. (R&M)	Philadelphia	PA	335,000	Sunoco, Inc.	37,489.00	4,544
Tenby Inc.	Oxnard	CA	2,800	Ten By Inc.	NotListed	NotListed
Tesoro Alaska Petroleum Co	Kenai	AK	68,000	Tesoro Corp	20,583.00	5,261
Tesoro Hawaii Corp	Ewa Beach	HI	93,500	Tesoro Corp	20,583.00	5,261
Tesoro Refining & Marketing Corporation	Martinez	CA	166,000	Tesoro Corp	20,583.00	5,261
Tesoro Refining & Marketing Corporation	Wilmington	CA	94,300	Tesoro Corp	20,583.00	5,261
Tesoro West Coast	Mandan	ND	58,000	Tesoro Corp	20,583.00	5,261
Tesoro West Coast	Salt Lake City	UT	57,500	Tesoro Corp	20,583.00	5,261
Tesoro West Coast	Anacortes	WA	120,000	Tesoro Corp	20,583.00	5,261
Total Petrochemicals Inc	Port Arthur	TX	232,000	Total SA	186,158.80	92,855
Trigeant Ltd.	Corpus Christi	TX		BTB Refining	5.00	37
United Refining Co.	Warren	PA	65,000	United Refining Company	2,654.40	4,434
US Oil & Refining Co.	Tacoma	WA	38,800	US Oil & Refining Co.	26.90	182
Valero Energy Corporation	Three Rivers	TX	93,000	Valero Energy	82,233.00	20,313
Valero Energy Corporation	Sunray	TX	156,000	Valero Energy	82,233.00	20,313
Valero Refining Co California	Benicia	CA	132,000	Valero Energy	82,233.00	20,313
Valero Refining Co California	Wilmington Asphalt Plant	CA	6,300	Valero Energy	82,233.00	20,313
Valero Refining Co California	Wilmington Refinery	CA	78,000	Valero Energy	82,233.00	20,313
Valero Refining Co Oklahoma	Ardmore	OK	85,000	Valero Energy	82,233.00	20,313

(continued)

Table A-1. Parent Company Information for Petroleum Refineries (continued)

Facility Name	City	State	Capacity (bbl/cd)	Parent Company Name	Parent Company Sales	Parent Company Employment
Valero Refining Co Texas LP	Corpus Christi	TX	142,000	Valero Energy	82,233.00	20,313
Valero Refining Co Texas LP	Houston	TX	88,000	Valero Energy	82,233.00	20,313
Valero Refining Co Texas LP	Texas City	TX	225,000	Valero Energy	82,233.00	20,313
Valero Refining New Orleans LLC	Norco	LA	205,000	Valero Energy	82,233.00	20,313
Ventura Refining & Transmission LLC	Thomas	OK	12,000	Ventura Refining & Transmission, LLC	3.10	37
Western Refining Company LP	El Paso	TX	122,000	Western Refining, Inc.	7,965.05	636
Western Refining Southwest Inc	Bloomfield	NM	16,800	Western Refining, Inc.	7,965.05	636
Western Refining Southwest Inc	Gallup	NM	21,100	Western Refining, Inc.	7,965.05	636
Western Refining Yorktown Inc	Yorktown	VA	66,300	Western Refining, Inc.	7,965.05	636
WRB Refining LLC	Borger	TX	146,000	ConocoPhillips	198,655.00	29,700
WRB Refining LLC	Wood River	IL	362,000	ConocoPhillips	198,655.00	29,700
Wynnewood Refining Co.	Wynnewood	OK	70,000	Gary-Williams Energy Corporation	49.90	260
Wyoming Refining Co	New Castle	WY	14,000	Wyoming Refining Co.	125.00	96

Sources: Hoovers 2011 Online Data, accessed through University of South Carolina's Moore School of Business Library. Hoovers 2011 Online Data reflects either actual data for 2010/2011 reported by companies, estimated data for 2011, or occasionally 2009 values.

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Oil & Gas Journal, December 6, 2010

Energy Information Administration (EIA), Form EIA-820, "Annual Refinery Report." Table 3. Capacity of Operable Petroleum Refineries by State and Individual Refinery as of January 1, 2011. (Data accessed on October 31, 2011.) [Source for 2009–2011 numbers.] <http://www.eia.gov/petroleum/refinerycapacity/

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