# Economic Impact Analysis

## Petroleum Refineries

## Final Amendments to the National Emissions Standards for Hazardous Air Pollutants and New Source Performance Standards

U.S. Environmental Protection Agency
Office of Air and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, NC 27711

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## ACKNOWLEDGEMENTS

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# TABLE OF CONTENTS

# LIST OF TABLES

## LIST OF FIGURES

# 1 EXECUTIVE SUMMARY

## 1.1 Background

As part of the regulatory process, EPA is required to perform economic analysis. EPA estimates the final NESHAP and NSPS amendments will have annualized cost impacts of less than $100 million, so the Agency has prepared an Economic Impact Analysis (EIA). This EIA includes an analysis of economic impacts anticipated from the final NESHAP and NSPS amendments. We also provide a small business impacts analysis within this EIA. We selected an analysis year of 2018.

## 1.2 Results

For the final rule amendments, the key results of the EIA follow:

- **Engineering Cost Analysis:** Total annualized engineering costs measure the costs incurred by affected industries annually. The annualized engineering costs for the final amendments are estimated to be $63.2 million[1], and the related emissions reductions for the final amendments are estimated to be 16,660 tons per year of VOC emissions reductions and 1,323 tons per year of HAP emissions reductions.[2] As discussed in Section 3, the annualized engineering costs include $13 million associated with requirements for storage vessels, delayed coking units, and fugitive emissions monitoring. The requirements would also result in $46.5 million in annual costs for flare monitoring, $3.3 million in annual costs to monitor relief device releases, and $400,000 in annual costs to conduct performance tests for the fluid catalytic cracking unit (FCCU) at existing sources.
- **Market Analysis:** The final amendments are predicted to induce minimal change in the average national price of refined petroleum products. Product prices are predicted to increase 0.0001% or less on average, while production levels decrease less than 0.0001% on average, as a result of the amendments.
- **Small Entity Analyses:** Based on updated data obtained through Hoover's, Inc. and some data collected through the April 2011 Information Collection Request (ICR), EPA performed a cost-to-sales screening analysis for impacts for 18 affected small refineries. The cost-to-sales ratio was below 1 percent for all affected small firms. As such, we determined that final amendments will not have a significant economic impact on a substantial number of small entities (SISNOSE).

[1] When not accounting for savings from product recovery credits, the annualized engineering costs for the final amendments are estimated to be $74.2 million. See Chapter 3, Section 3.2 for more discussion of savings from product recovery credits.

[2] Note that this estimate does not reflect any corrective action taken in response to the fenceline monitoring program and some other testing requirements of the amendments. Any corrective actions associated with these provisions will result in additional emissions reductions and additional costs.

- **Employment Impacts Analysis:** We provide a qualitative framework for considering the potential influence of environmental regulation on employment in the U.S. economy, and we discuss the limited empirical literature available. The discussion focuses on both short- and long-term employment impacts on regulated industries.

## 1.3 Organization of this Report

The remainder of this report details the methodology and the results of the EIA. Section 2 presents the industry profile of the petroleum refining industry. Section 3 describes the emissions and engineering cost analyses. Section 4 presents market, employment impact, and small business impact analyses.

# 2 INDUSTRY PROFILE

## 2.1 Introduction

The petroleum refining industry is comprised of establishments primarily engaged in refining crude petroleum into finished petroleum products. Examples of these products include gasoline, jet fuel, kerosene, asphalt, lubricants, and solvents. Firms engaged in petroleum refining are categorized under the North American Industry Classification System (NAICS) code 324110. In 2013, 143 establishments owned by 64 parent companies were refining petroleum in the continental United States. In 2013, the petroleum refining industry shipped products valued at over $693 billion (U.S. Census Bureau, 2013).

This profile of the petroleum refining industry 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; and Section 2.5 contains market-level data on prices and quantities and discusses trends and projections for the industry. In addition, small business information is 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).

## 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, product 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 Product Outputs*

Petroleum pumped directly out of the ground, or 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 complex 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. 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. 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.

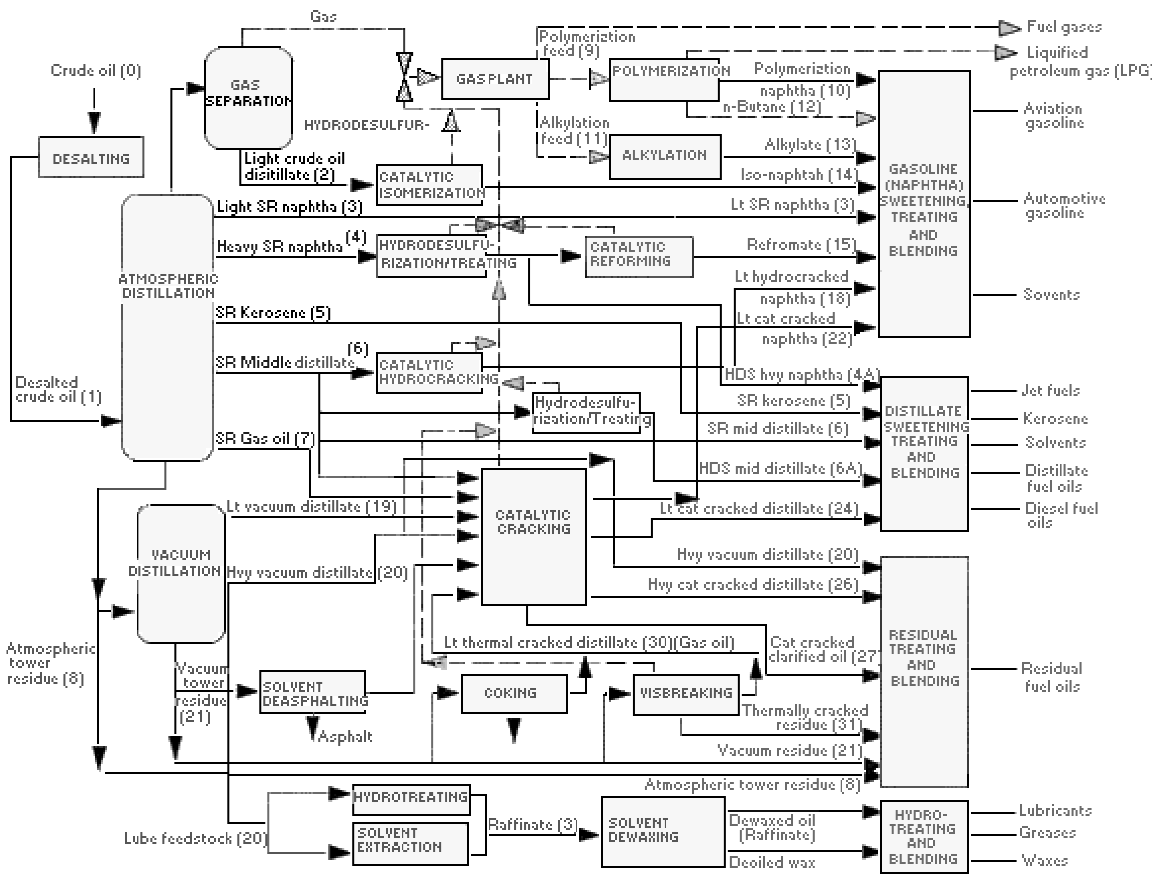


**Figure 2-1 Outline of the Refining Process**

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>.

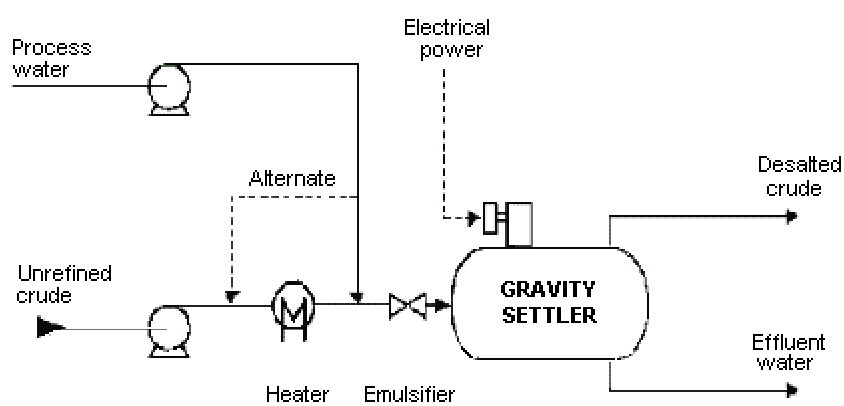


**Figure 2-2 Desalting Process**

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>.

**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 a 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).

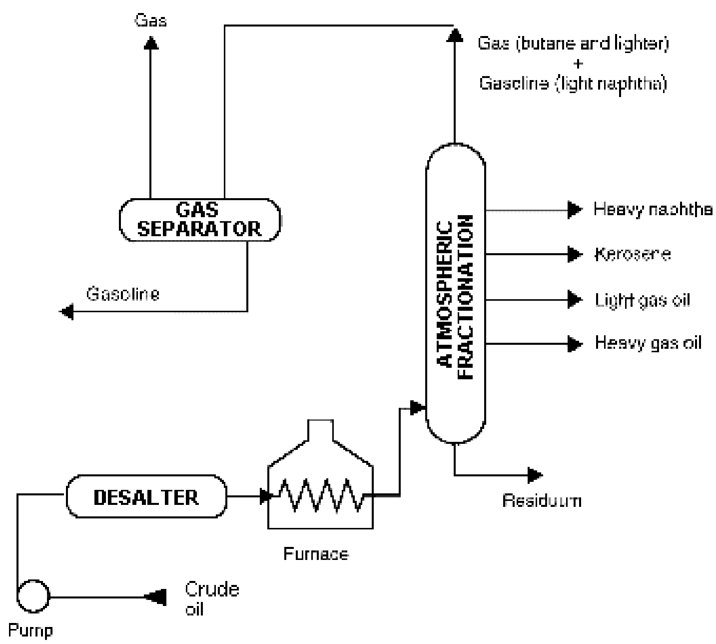


**Figure 2-3 Atmospheric Distillation Process**

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>.

**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.

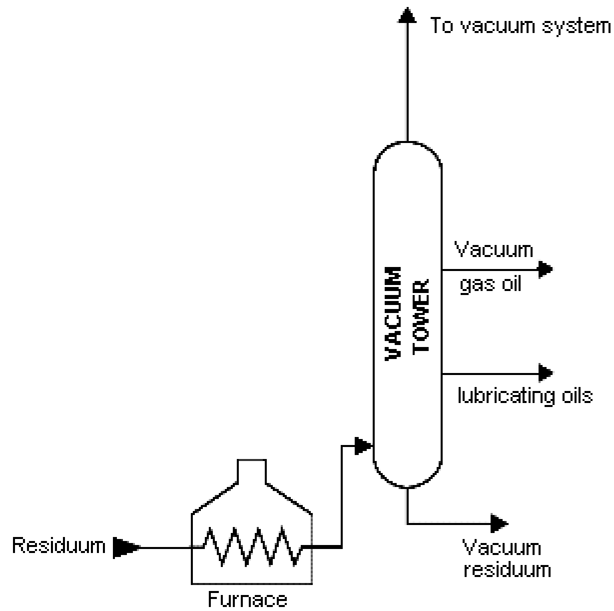


**Figure 2-4 Vacuum Distillation Process**

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>.

**Downstream Processing.** To produce the petroleum products desired in the market place, most fractions must be further refined after distillation by "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. 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 below.

**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 use two stages of wastewater treatment. In primary wastewater treatment, 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, since the 1970s ethers have been added to gasoline to increase octane levels and reduce CO emissions.

**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 gas, natural gas, distillate oil, or residual oil. 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 accidents. 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.[3] 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 2013, the petroleum refining industry used 5.6 billion barrels of crude oil in the production of finished petroleum products (EIA, 2013).[4]

**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

[3] 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, 1992).
[4] A barrel is a unit of volume that is equal to 42 U.S. gallons.

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**

| 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>.

In 2013, the petroleum refining industry used 2.1 billion barrels of natural gas liquids and other liquids in the production of finished petroleum products (EIA, 2013).

#### *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>.

### *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. 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 (Docket ID No. EPA-HQ-OAR-2007-0011).

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 sludge, 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 2011, 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.

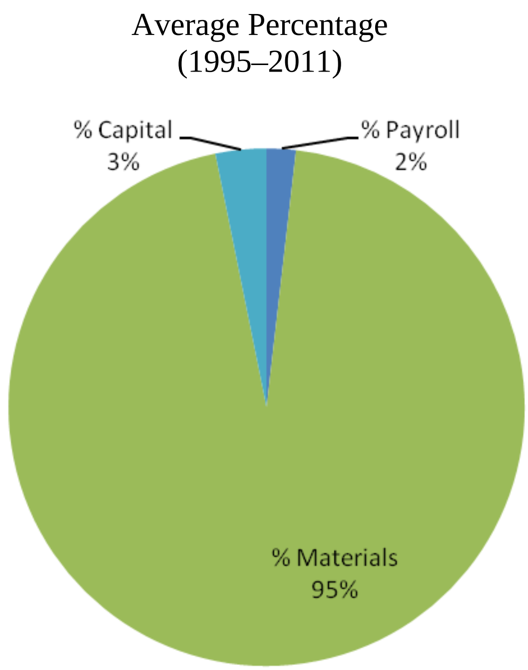


**Figure 2-5 Petroleum Refinery Expenditures**

Sources: U.S. Department of Commerce, Bureau of the Census, American FactFinder; "Sector 31: Annual Survey of Manufactures: General Statistics: Statistics for Industry Groups and Industries: 2011 and 2010 " Data accessed on 12/19/14). [Source for 2010 and 2011 numbers] <http://factfinder2.census.gov/faces/tableservices/jsf/pages/productview.xhtml?pid=ASM_2011_31GS101 &prodType=table>

U.S. Department of Commerce, Bureau of the Census, American FactFinder; "Sector 31: Annual Survey of Manufactures: General Statistics: Statistics for Industry Groups and Industries: 2009 and 2008" (Data accessed on 10/10/11). [Source for 2009 and 2008 numbers] < http://factfinder.census.gov >

U.S. Department of Commerce, Bureau of the Census, American FactFinder; "Sector 31: Manufacturing: Industry Series: Detailed Statistics by Industry for the United States: 2007" (Data accessed on 10/11/11). [Source for 2007 numbers] Obtained through American Fact Finder Database< http://factfinder.census.gov >.

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

U.S. Department of Commerce, Bureau of the Census. 2003a. *2001 Annual Survey of Manufactures*. M01(AS)-1. Washington, DC: Government Printing Office. Available at <http://www.census.gov/prod/2003pubs/m01as-2.pdf>

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

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

U.S. Department of Commerce, Bureau of the Census. 1997. *1995 Annual Survey of Manufactures*. M95(AS)-1. Washington, DC: Government Printing Office. Available at http://www.census.gov/prod/2/manmin/asm/m95as1.pdf

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 17-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** | **2011** | **Reported** | **2011** | **Reported** | **2011** |
| 1995 | 3,791 | 5,772 | 112,532 | 171,335 | 5,937 | 9,039 |
| 1996 | 3,738 | 5,561 | 132,880 | 197,700 | 5,265 | 7,833 |
| 1997 | 3,885 | 5,762 | 127,555 | 189,182 | 4,244 | 6,294 |
| 1998 | 3,695 | 5,537 | 92,212 | 138,172 | 4,169 | 6,247 |
| 1999 | 3,983 | 5,871 | 114,131 | 168,216 | 3,943 | 5,812 |
| 2000 | 3,992 | 5,655 | 180,568 | 255,771 | 4,685 | 6,636 |
| 2001 | 4,233 | 5,947 | 158,733 | 223,005 | 6,817 | 9,577 |
| 2002 | 4,386 | 6,203 | 166,368 | 235,304 | 5,152 | 7,287 |
| 2003 | 4,752 | 6,554 | 185,369 | 255,677 | 6,828 | 9,418 |
| 2004 | 5,340 | 7,066 | 251,467 | 332,767 | 6,601 | 8,735 |
| 2005 | 5,796 | 7,268 | 345,207 | 432,882 | 10,525 | 13,198 |
| 2006 | 5,984 | 7,212 | 396,980 | 478,451 | 11,175 | 13,468 |
| 2007 | 6,357 | 7,379 | 470,946 | 546,690 | 17,105 | 19,856 |
| 2008 | 6,313 | 6,791 | 649,784 | 698,942 | 17,660 | 18,996 |
| 2009 | 6,400 | 7,243 | 398,679 | 451,169 | 16,824 | 19,039 |
| 2010 | 6,323 | 6,816 | 512,843 | 552,900 | 11,697 | 12,611 |
| 2011 | 6,582 | 6,582 | 688,912 | 688,912 | 9,602 | 9,602 |

Note: Adjusted for inflation using the Bureau of Labor's Producer Price Index Industry Data for total manufacturing industries.

Sources: U.S. Department of Commerce, Bureau of the Census, American FactFinder; "Sector 31: Annual Survey of Manufactures: General Statistics: Statistics for Industry Groups and Industries: 2011 and 2010 " (Data accessed on 12/19/14). [Source for 2010 and 2011 numbers] <http://factfinder2.census.gov/faces/tableservices/jsf/pages/productview.xhtml?pid=ASM_2011_31GS101&prodType=table>

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U.S. Department of Commerce, Bureau of the Census, American FactFinder; "Sector 31: Manufacturing: Industry Series: Detailed Statistics by Industry for the United States: 2007" (Data accessed on 10/11/11). [Source for 2007 numbers] < http://factfinder.census.gov >

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 Manufactures*. 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.

### 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% |

D – Data is withheld to avoid disclosing data of individual companies; data are included in higher level totals.

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. Department of Commerce, Bureau of the Census, American FactFinder; "Sector 31: Manufacturing: Industry Series: Materials Consumed by Kind for the United States: 2007" (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; and
- **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 Product 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 as federal, state, and local government institutions; and
- 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 benzyne, 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 in 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 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 2013, motor gasoline alone accounted for 57% of demand for finished petroleum products (EIA, 2013a). Of the end users, the transportation sector consumes the largest share of petroleum products, accounting for 67% of total consumption in 2005 (EIA, 2013a). 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).

### *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. 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).

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 substitution of ethanol (an alcohol produced from biomass) 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.

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 the level to which 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 for 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 concentration are reported for the petroleum refining industry (NAICS 324110) in Table 2-6 for selected years between 1985 and 2007.[5]

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.

[5] Industry concentration ratios after 2007 were not available from the U.S. Census Bureau.

**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. Department of Commerce, Bureau of the Census, 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>

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, initially created during World War II to help manage the allocation of fuels during wartime, separate the United States into five geographic regions or districts. PADDs remain in use as a convenient way of organizing petroleum market information (FTC, 2004).

The FTC 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 (West Coast) 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 2.3 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*

At the beginning of 2014, there were approximately 142 petroleum refineries operating in the United States, spread across 31 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 efficiently 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 2013. 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 did not appear to be evidence that demand for petroleum products was 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 | 18 |
| 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 | 3 |
| New Mexico | 2 |
| North Dakota | 1 |
| Ohio | 4 |
| Oklahoma | 6 |
| Pennsylvania | 4 |
| Tennessee | 1 |
| Texas | 27 |
| Utah | 5 |
| Washington | 5 |
| West Virginia | 1 |
| Wisconsin | 1 |
| Wyoming | 6 |
| Total | 142 |

Source: U.S. Department of Energy, 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, 2014" (Data accessed on 12/22/14). [Source for 2014 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 |
| 2011 | 86.2 | 15,289 | 17,736 |
| 2012 | 88.7 | 15,373 | 17,328 |
| 2013 | 88.3 | 15,724 | 17,818 |

Sources: U.S. Department of Energy, Energy Information Administration (EIA), "Refinery Utilization and Capacity." Available at http://www.eia.gov/dnav/pet/pet_pnp_unc_dcu_nus_a.htm; (Data accessed on 12/22/14).

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. Since 2009, both operational capacity and gross inputs have generally increased.

#### *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 (SBA, 2011).[6] 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 2014, there were 142 petroleum refineries operating in the continental United States and US territories with a cumulative capacity of processing over 17 million barrels

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

of crude per calendar day (EIA, 2014). We identified 57 parent companies owning refineries in the United States and were able to collect employment and sales data for 52, or 91%, of them.

The distribution of employment across companies is illustrated in Figure 2-6. As this figure shows, 18 facilities (owned by 22 parent companies) employ fewer than 1,500 workers and would be considered small businesses. These firms earned an average of $1.74 billion of revenue per year, while firms employing more than 1,500 employees earned an average of $67 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. 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.

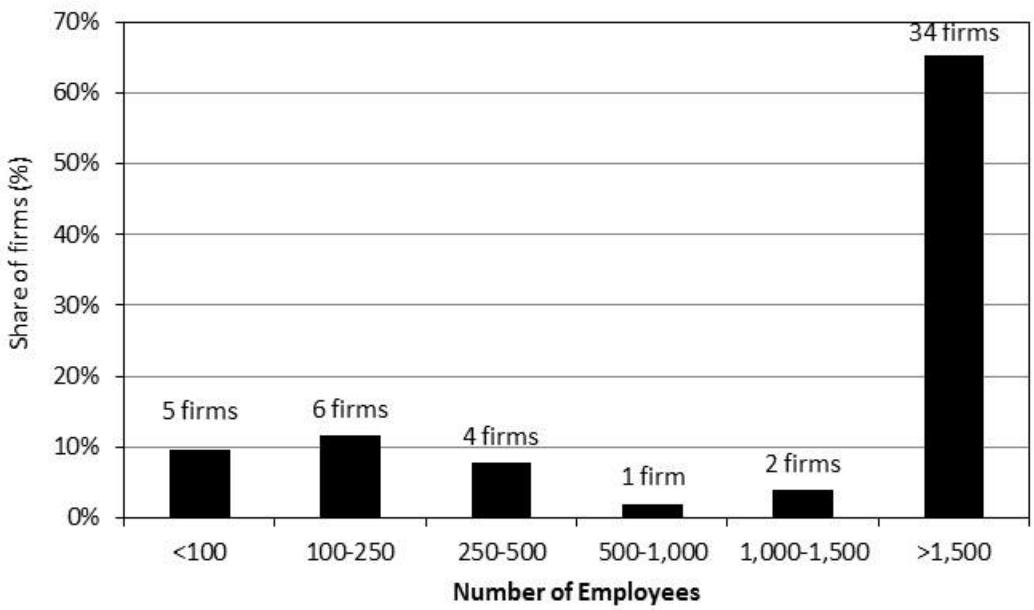


**Figure 2-6 Employment Distribution of Companies Owning Petroleum Refineries (N=52 Parent Companies)**

Sources: Hoovers 2013 Online Data, which reflects either actual sales and employment data for 2013 or estimated data for 2014. Where data was not available through Hoovers, we used employment and sales data from Petroleum Refinery Emissions Information Collection, where available, Component 1, OMB Control No. 2060-0657.

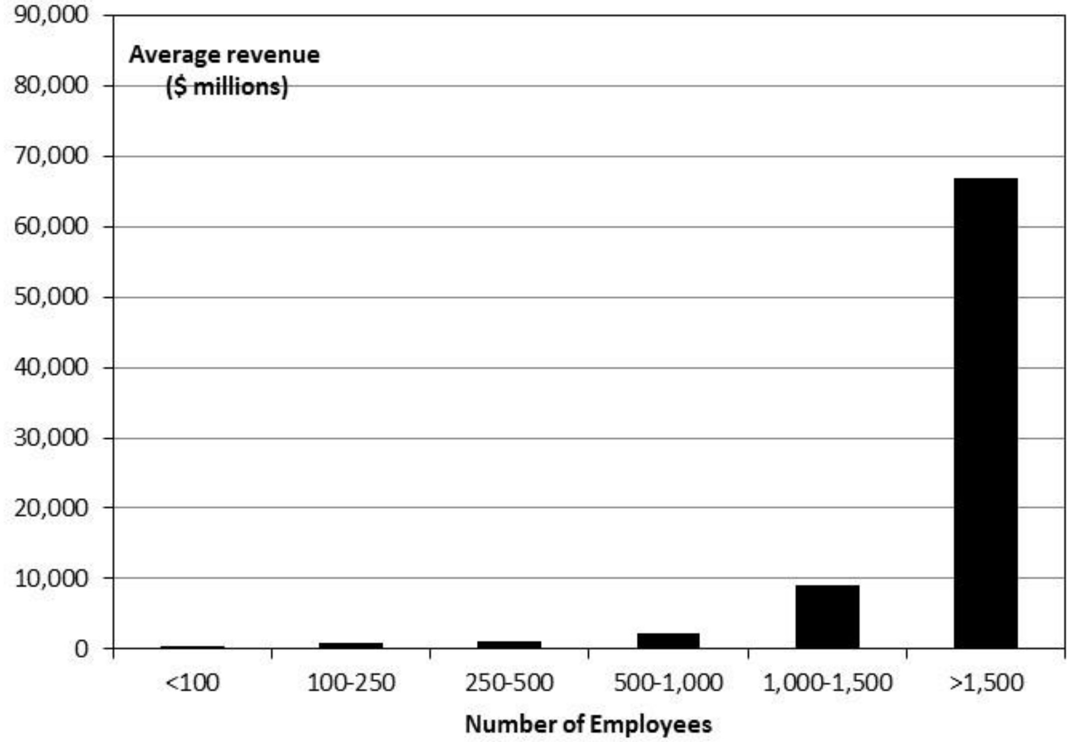


**Figure 2-7 Average Revenue of Companies Owning Petroleum Refineries by Employment (N=52 Parent Companies)**

Sources: Hoovers 2013 Online Data, which reflects either actual sales and employment data for 2013 or estimated data for 2014. Where data was not available through Hoovers, we used employment and sales data from Petroleum Refinery Emissions Information Collection, where available, Component 1, OMB Control No. 2060-0657.

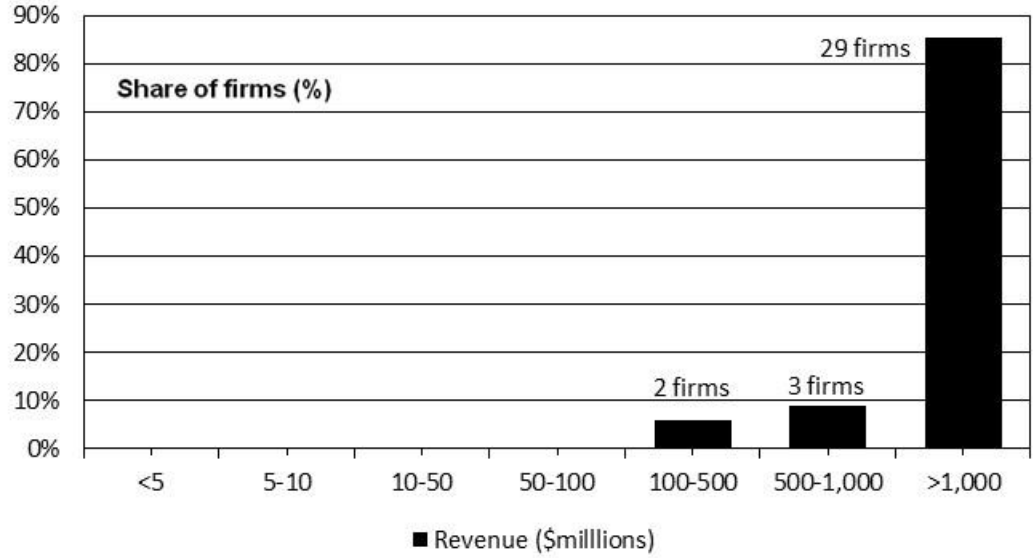


**Figure 2-8 Revenue Distribution of Large Companies Owning Petroleum Refineries (N=30 Parent Companies)**

Sources: Hoovers 2013 Online Data, which reflects either actual sales and employment data for 2013 or estimated data for 2014. Where data was not available through Hoovers, we used employment and sales data from Petroleum Refinery Emissions Information Collection, where available, Component 1, OMB Control No. 2060-0657.

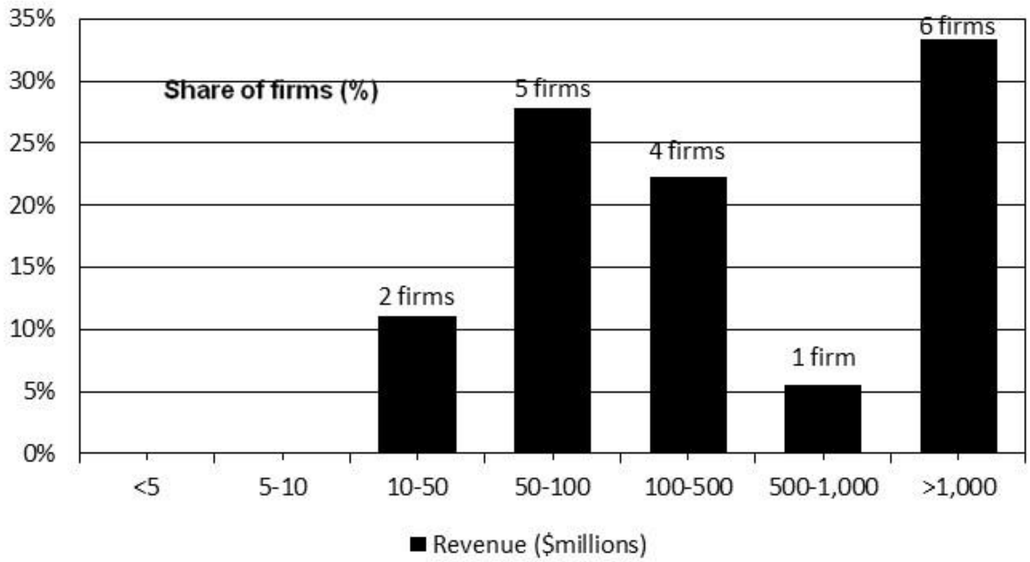


**Figure 2-9 Revenue Distribution of Small Companies Owning Petroleum Refineries (N=18 Parent Companies)**

Sources: Hoovers 2013 Online Data, which reflects either actual sales and employment data for 2013 or estimated data for 2014. Where data was not available through Hoovers, we used employment and sales data from Petroleum Refinery Emissions Information Collection, where available, Component 1, OMB Control No. 2060-0657.

In Section 2.4.2.1, 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 Holding Corporation, which was started in the 1930s for the 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 Lubricants, LP. The firm produces specialty products like lubricating oils, solvents, waxes, and other petroleum products -- the firm's specialty products unit is its largest unit (Hoovers, 2013).

However, recent developments are making these factors less important for success in the industry. For example, the entry of new product pipelines may be eroding the locational advantage of smaller refineries (FTC, 2004). Most refineries owned by small businesses tend to be located in relatively rural areas – as shown in Table 2-9, the mean population density of counties occupied by small refineries is 369 people per square mile. This suggests 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 2.4.1.3, 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 2013 (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) |
|---|---|---|---|---|---|---|---|---|---|
| American Refining Group, Inc. | Private | 11,000 | 323 | American Refining Group Inc. | Bradford | PA | McKean County | 47 | 44 |
| Calcasieu Refining Company | Private | 78,000 | 92 | Calcasieu Refining Company | Lake Charles | LA | Calcasieu Parish | 171 | 181 |
| Calumet Shreveport Lubricants and Waxes, LLC | Public | 57,000 | 654 | Calumet Lubricants LP | Shreveport | LA | Caddo Parish | 286 | 290 |
| Connacher Oil & Gas Limited | Public | 10,000 | 168 | Montana Refining Co. | Great Falls | MT | Cascade County | 30 | 30 |
| CVR Energy, Inc. | Public | 115,000 | 1,298 | Coffeyville Resources LLC | Coffeyville | KS | Montgomery County | 56 | 55 |
| Countrymark Cooperative Holding Corporation | Private | 27,000 | 425 | Countrymark Cooperative, Inc. | Mt. Vernon | IN | Posey County | 66 | 63 |
| Foreland Refining Corporation | Private | 2,000 | 100 | Foreland Refining Corporation | Ely | NV | White Pine County | 1 | 1 |
| CVR Energy Inc. | Private | 70,000 | 1,298 | 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 |
| Kern Oil & Refining Co. | Private | 26,000 | 105 | Kern Oil & Refining Co. | Bakersfield | CA | Kern County | 81 | 103 |
| Pasadena Refining Systems Inc. | Private | 100,000 | 348 | Pasadena Refining Systems Inc. | Pasadena | TX | Harris County | 1967 | 2,402 |
| Placid Refining Company LLC | Private | 59,000 | 3 | Placid Refining Company LLC | Port Allen | LA | West Baton Rouge Parish | 113 | 124 |
| Kenneth Faite (San Joaquin) | 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 |

**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) |
|---|---|---|---|---|---|---|---|---|---|
| Somerset Oil Inc. | Private | 5,500 | 11 | Continental Refining Company, Inc. | Somerset | KY | Pulaski County | 85 | 96 |
| Trailstone Management Corp. | Private | 38,800 | 160 | US Oil & Refining Co. | Tacoma | WA | Pierce County | 417 | 476 |
| Ventura, LLC | Private | 12,000 | 37 | Ventura Refinery | Thomas | OK | Custer County | 27 | 28 |
| World Oil Marketing Company | Private | 8,500 | 475 | Lunday-Thagard Co. | South Gate | CA | Los Angeles County | 2,344 | 2,420 |
| **Total** | | 782,832 | 12,233 | | | | | **Average** | 369 |

Sources: U.S. Department of Commerce, Bureau of the Census, American Fact Finder, "2010 Census Summary File 1 Population, Housing Units, Area & Density: 2010- County – Census Tract 100% Data 2010 Census" (Data accessed on 12/22/2014); http://factfinder2.census.gov/faces/tableservices/jsf/pages/productview.xhtml?ftp=table

U.S. Department of Commerce, Bureau of the Census, American Fact Finder, "2000 Census Summary File 1 Population, Housing Units, Area & Density: 2000- County – Census Tract 100% Data 2000 Census" (Data accessed on 12/22/2014); http://factfinder.census.gov/faces/tableservices/jsf/pages/productview.xhtml?src=CF

Employment and Sales data from Hoovers.com. (Data accessed on 12/18/2014 and 6/22/2015). Where data was missing from Hoovers.com, employment and sales data from Petroleum Refinery Emissions Information Collection, Component 1, OMB Control No. 2060-0657, was used.

U.S. Department of Energy, 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, 2014 < http://www.eia.gov/petroleum/refinerycapacity/table3.pdf/>

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, and consumption of all petroleum products, except for liquified petroleum gases, decreased between 2010 and 2012. The cumulative decrease in consumption over the 14 year period is 4% (Table 2-10).

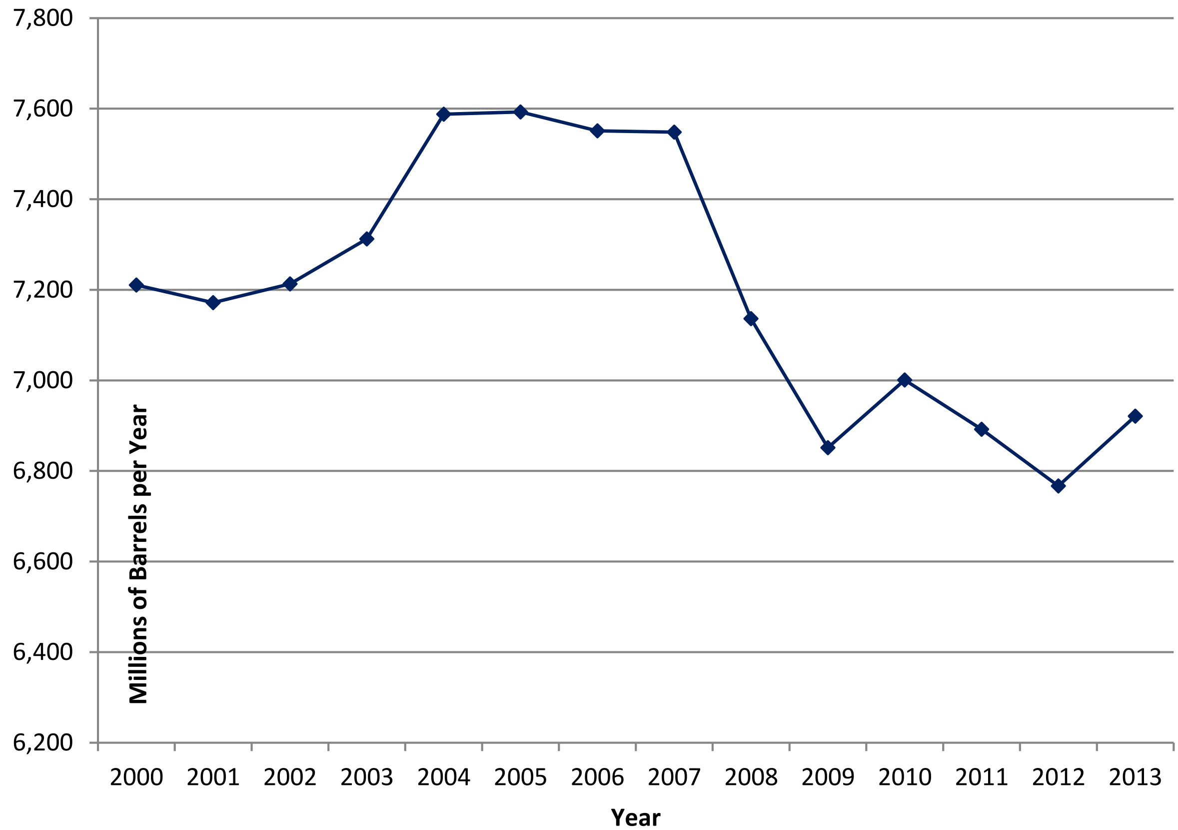


**Figure 2-10 Total Petroleum Products Supplied (millions of barrels per year)**

Sources: U.S. Department of Energy, 2013 Energy Information Administration (EIA). 1996–2013. “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>. (Data accessed on 12/23/2014) [Source for 2007-2013 numbers.]

**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 |
| 2011 | 3,195 | 520 | 1,423 | 168 | 805 | 781 | 6,892 |
| 2012 | 3,178 | 518 | 1,369 | 135 | 823 | 744 | 6,767 |
| 2013 | 3,228 | 524 | 1,397 | 116 | 890 | 766 | 6,921 |

Sources: U.S. Department of Energy, 2013 Energy Information Administration (EIA). 1996–2013. "Petroleum Supply Annuals, Volume 1." (Data accessed on 12/23/2014) [Source for 2000-2013 numbers.] <http://www.eia.gov/dnav/pet/pet_cons_psup_dc_nus_mbbl_a.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 2013. U.S. production of petroleum products at refineries and blenders grew steadily, resulting in a 10% cumulative increase for the period. However, in 2005, 2009, and 2012 production declined 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 |
| 2011 | 3,306 | 529 | 1,640 | 196 | 226 | 919 | 6,815 |
| 2012 | 3,267 | 538 | 1,665 | 183 | 230 | 911 | 6,794 |
| 2013 | 3,370 | 547 | 1,727 | 170 | 227 | 933 | 6,974 |

Sources: U.S. Department of Energy, 2013 Energy Information Administration (EIA). 1996–2013. "Petroleum Supply Annuals, Volume 1." (Data accessed on 12/23/2014) [Source for 2007-2013 numbers.] <http://www.eia.gov/dnav/pet/pet_pnp_refp_dc_nus_mbbl_a.htm>.

The 2005 decline in production (0.35%) was likely 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 2011.

### *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 2013 exports of petroleum products such as motor gasoline, jet fuel, distillate fuel oil and liquefied petroleum gases have increased significantly.

Since 2006, industry import and export trends have diverged significantly. Between 2006 and 2013 imports declined by 41%, returning close to 1999 levels. In 2013, U.S. net imports were a negative 545 million barrels. Exports grew at an average annual rate of 22% and in 2013 were 3.8 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 in 2014 U.S. net imports of crude oil, based on a four-week average, ranged from 6,991 to 7,761 thousand barrels per day. 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 2014a).[7]

[7] 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, U.S. Production**

| Year | Millions of $ Reported | Millions of $2011 |
|---|---|---|
| 1997 | 152,756 | 226,558 |
| 1998 | 114,439 | 171,477 |
| 1999 | 140,084 | 206,468 |
| 2000 | 210,187 | 297,726 |
| 2001 | 195,898 | 275,218 |
| 2002 | 186,761 | 264,147 |
| 2003 | 216,764 | 298,979 |
| 2004 | 290,280 | 384,129 |
| 2005 | 419,063 | 525,496 |
| 2006 | 486,570 | 586,426 |
| 2007 | 551,997 | 640,778 |
| 2008 | 678,004 | 729,297 |
| 2009 | 435,096 | 492,380 |
| 2010 | 552,041 | 595,159 |
| 2011 | 749,117 | 749,117 |

Note: Numbers were adjusted for inflation using the Producer Price Index Industry data for Total Manufacturing Industries.

Sources: U.S. Department of Commerce, Bureau of the Census, FactFinder. 2013. 2009 and 2011 Annual Survey of Manufactures. 1996–2011. Obtained through American Fact Finder Database. (Data accessed on 12/23/2014) [Source for 2008-2011 numbers] <http://factfinder.census.gov/faces/tableservices/jsf/pages/productview.xhtml?pid=ASM_2009_31VS101&prodType=table>.

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/faces/tableservices/jsf/pages/productview.xhtml?pid=ASM_2006_31GS101&prodType=table.

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.

## 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 |
| 2011 | 38 | 25 | 65 | 120 | 49 | 616 | 913 |
| 2012 | 16 | 20 | 46 | 94 | 52 | 530 | 758 |
| 2013 | 16 | 31 | 56 | 82 | 54 | 538 | 777 |

Sources: U.S. Department of Energy, 2013 Energy Information Administration (EIA). 1995–2013. "Petroleum Supply Annuals, Volume 1." (Data accessed on 12/23/2014) [Source for 1995-2013 numbers.] <http://www.eia.gov/dnav/pet/pet_move_impcus_d_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 | 858 |
| 2011 | 175 | 35 | 312 | 155 | 54 | 359 | 1,090 |
| 2012 | 150 | 48 | 369 | 142 | 72 | 392 | 1,173 |
| 2013 | 136 | 57 | 414 | 132 | 121 | 462 | 1,322 |

Sources: U.S. Department of Energy, 2013 Energy Information Administration (EIA). 1995–2013. "Petroleum Supply Annuals, Volume 1." (Data accessed on 12/23/2014) [Source for 1995-2013 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.[8] 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 and 2013 nominal prices increased. During the 2008–2013 period, the most volatile price was jet fuel price: it declined by 44% in 2009 and increased by 75% by 2013.

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

| Product | 1995 | 2000 | 2005 | 2008 | 2009 | 2010 | 2013 |
|---|---|---|---|---|---|---|---|
| Motor gasoline | 76.5 | 110.6 | 183 | 278 | 189 | 230 | 305 |
| No. 1 distillate fuel | 62.0 | 98.8 | 183 | 298 | 214 | 271 | 348 |
| No. 2 distillate fuel | 56.0 | 93.4 | 178 | 314 | 184 | 232 | 313 |
| Jet fuel | 54.0 | 89.9 | 174 | 305 | 170 | 220 | 298 |
| Residual fuel oil | 39.2 | 60.2 | 105 | 196 | 134 | 171 | 248 |

Note: Prices do not include taxes.

Sources: U.S. Department of Energy, Energy Information Administration (EIA). 2013. “Refiner Petroleum Product Prices by Sales Type.” Available at <http://www.eia.gov/dnav/pet/pet_pri_refoth_dcu_nus_a.htm>. As obtained on January 5, 2015.

U.S. Department of Energy, 2013b Energy Information Administration (EIA). 1995–2013. “Petroleum Supply Annuals, Volume 1.” (Data accessed on 12/23/2014) [Source for 1995-2013 numbers] <http://www.eia.gov/dnav/pet/pet_move_exp_dc_NUS-Z00_mbbl_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 2013, prices received by petroleum refineries for their products rose by almost 400%, while prices received by all manufacturing firms rose by 56%. 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.

[8] 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 2-16  Producer Price Index Industry Data: 1995 to 2013**

| | 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% |
| 2011 | 383.7 | 33% | 189.1 | 8% |
| 2012 | 387.9 | 1% | 193.1 | 2% |
| 2013 | 371.1 | -4% | 193.9 | 0% |

Sources: U.S. Bureau of Labor Statistics (BLS). 2014. "Producer Price Index Industry Data: Customizable Industry Data Tables." (Data accessed on January 5, 2015.) <http://data.bls.gov/cgi-bin/dsrv?pc>.

### *2.5.5 Profitability of Petroleum Refineries*

A ratio of profitability calculated as net income divided by revenues, or sales, measures how much out of every dollar of sales a company actually keeps in earnings – a 5% profit margin, for example, means the company has a net income of $0.05 for each dollar.  A higher ratio of profitability indicates a more profitable company that may have better control over costs compared to its competitors. 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 because most of these firms are privately owned. However, two of the small, domestic petroleum refining firms identified in Section 3.4.2.3 are publicly owned companies — CVR Energy Inc. and Calumet Specialty Products Partners, L.P. Table 2-18 presents profit ratios calculated for these companies using data obtained from their publicly available 2013 annual reports.

**Table 2-18 Net Profit Margins for Publicly Owned, Small Petroleum Refiners: 2012-2013**

| Company | Net Income ($millions) | Total Revenue ($millions) | Net Profit Margin (%) |
|---|---|---|---|
| Calumet Specialty Products Partners, L.P. (2012) | 206 | 4,657 | 4.4% |
| Calumet Specialty Products Partners, L.P. (2013) | 4 | 5,421 | 0.07% |
| CVR Energy Inc. (2012) | 412.6 | 8,567.3 | 4.8% |
| CVR Energy Inc. (2013) | 522 | 8,985.8 | 5.8% |

Sources: Calumet Specialty Products Partners, L.P., 10 K for year ended December 31, 2013. (Data accessed on 01/06/15) [Source for 2012 and 2013 numbers.] <http://calumetspecialty.investorroom.com/Annual-Reports>

CVR Energy Inc., 10 K for year ended December 31, 2013. (Data accessed on 01/06/15) [Source for 2013 numbers.] <http://investors.cvrenergy.com/phoenix.zhtml?c=203637&p=proxy>

### *2.5.6 Industry Trends*

The Energy Information Administration's (EIA's) 2014 Annual Energy Outlook (AEO) provides forecasts of average petroleum prices, petroleum product consumption, and petroleum refining capacity utilization to the year 2040. 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 generally unchanged throughout the projection period.

Oil prices are influenced by several factors, including some that have mainly short-term impacts. Other factors, such as expectations about future world demand for petroleum and other liquids and production decisions by the Organization of the Petroleum Exporting Countries (OPEC), influence prices over the longer term. Supply and demand in the world oil market are balanced through responses to changes in prices, with considerable complexity associated with changes in expectations for supply and demand. For petroleum and other liquids, the key determinants of long-term supply and prices can be summarized in four broad categories: the economics of non-OPEC supply; OPEC investment and production decisions; the economics of other liquids supply; and world demand for petroleum and other liquids.

In the AEO2014 reference case, key assumptions driving global crude oil markets over the projection period include: average economic growth of 1.9% per year for major U.S. trading partners and average economic growth of 4.0% per year for other U.S. trading partners. Growth in petroleum and other liquids use occurs almost exclusively outside the Organization for Economic Cooperation and Development (OECD) member countries, with 1.8% average annual growth in petroleum and other liquids consumption by non-OECD countries, including significantly higher average annual consumption growth in both China and India.

Also in the 2014 AEO reference case, consumption of petroleum and other liquids remains relatively flat. While the transportation sector accounts for the largest share of total consumption throughout the projection, its share falls from 72% in 2013 to 65% in 2040, as a result of improvements in vehicle efficiency following the incorporation of corporate average fuel economy (CAFE) standards for both light-duty vehicles and heavy-duty vehicles. The prices of some petroleum products sold to end users are expected to decrease and then increase through 2030 (Table 2-19). Tighter fuel efficiency standards result in a decline in motor gasoline supplied, but there is growth in the other petroleum products supplied through 2030 (Table 2-20). Between 2014 and 2019, the prices of major petroleum products are expected to decrease by up to 9%, while consumption of all of those products is expected to rise by 5%. The price of motor gasoline, the most supplied product, is projected to decrease by almost 9% between 2014 and 2019 and increase by 11% from 2020 to 2030, while its consumption is projected to decrease by about 18% over the time period.

**Table 2-19 Forecasted Average Price of Major Petroleum Products Sold to End Users in 2012 Currency (cents per gallon)**

| Product | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2025 | 2030 |
|---|---|---|---|---|---|---|---|---|---|
| Motor gasoline | 336.9 | 317.7 | 307.2 | 302.7 | 302.1 | 303.5 | 307.7 | 329.1 | 342.8 |
| Diesel | 368.3 | 354.4 | 349.5 | 349.7 | 353.4 | 361.1 | 367.2 | 397.7 | 420.4 |
| Jet fuel | 279.5 | 257.3 | 248.4 | 245.6 | 248.3 | 256.3 | 262.9 | 296.5 | 320.1 |
| Residential distillate fuel oil | 353.9 | 339.2 | 329.8 | 326.2 | 329.0 | 335.7 | 342.2 | 373.7 | 396.7 |

Sources: U.S. Department of Energy, Energy Information Administration (EIA). 2014b. “2014 Annual Energy Outlook.” Available at <http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2014&subject=3-AEO2014&table=70-AEO2014&region=1-0&cases=ref2014-d102413a>. As obtained on January 6, 2015.

**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 |
|---|---|---|---|---|---|---|---|
| 2014 | 3,165 | 513 | 1,427 | 128 | 882 | 711 | 6,826 |
| 2015 | 3,201 | 533 | 1,491 | 141 | 894 | 735 | 6,996 |
| 2016 | 3,185 | 535 | 1,525 | 142 | 927 | 755 | 7,069 |
| 2017 | 3,163 | 538 | 1,543 | 140 | 949 | 779 | 7,113 |
| 2018 | 3,131 | 540 | 1,552 | 142 | 966 | 800 | 7,131 |
| 2019 | 3,090 | 542 | 1,560 | 142 | 983 | 816 | 7,134 |
| 2020 | 3,048 | 544 | 1,568 | 142 | 996 | 831 | 7,128 |
| 2025 | 2,800 | 556 | 1,620 | 143 | 1,038 | 878 | 7,034 |
| 2030 | 2,608 | 566 | 1,648 | 145 | 1,037 | 907 | 6,911 |

Sources: U.S. Department of Energy, Energy Information Administration (EIA). 2104b. "Annual Energy Outlook." Available at <http://www.eia.gov/forecasts/aeo/tables_ref.cfm>. As obtained on January 7, 2015.

Overall, the EIA forecasts that U.S. operational capacity will increase by about 2% between 2014 and 2030 (Table 2-21). The rate of capacity utilization is projected to average 84% 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)[9] | Operational Capacity (1,000s of barrels per day) |
|---|---|---|---|
| 2014 | 87.0% | 15,503 | 17,819 |
| 2015 | 83.9% | 15,203 | 18,115 |
| 2016 | 84.4% | 15,310 | 18,130 |
| 2017 | 84.8% | 15,371 | 18,130 |
| 2018 | 84.9% | 15,384 | 18,130 |
| 2019 | 85.8% | 15,367 | 18,130 |
| 2020 | 84.6% | 15,340 | 18,130 |
| 2025 | 83.1% | 15,057 | 18,130 |
| 2030 | 82.4% | 14,940 | 18,130 |

Sources: U.S. Department of Energy, Energy Information Administration (EIA). 2014b. "Annual Energy Outlook." Available at <http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2014ER&subject=8-AEO2014ER&table=11-AEO2014ER&region=0-0&cases=ref2014er-d102413a>. As obtained on January 7, 2015.

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[9] For each year, the gross input to atmospheric crude oil distillation units is calculated by multiplying the capacity utilization rate by the operational capacity.

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# 3 EMISSIONS AND ENGINEERING COSTS

## 3.1 Introduction

The emissions standards that are the subject of the rulemaking include: (1) National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries (40 CFR part 63, subpart CC) (Refinery MACT 1); (2) National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units (40 CFR part 63, subpart UUU) (Refinery MACT 2); (3) Standards of Performance for Petroleum Refineries (40 CFR part 60, subpart J) (Refinery NSPS J); and (4) Standards of Performance for Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After May 14, 2007 (40 CFR part 60, subpart Ja) (Refinery NSPS Ja). The sources or processes affected by amendments to these standards include storage vessels, delayed coking units, and fugitive emissions subject to Refinery MACT 1. The amendments also reflect requirements to ensure compliance, including flare monitoring and operational requirements, requirements for relief valve monitoring, and emissions source performance tests for the fluid catalytic cracking units (FCCUs) at existing sources (Refinery MACT 2). In addition, these amendments address technical corrections and clarifications raised in a 2008 industry petition for reconsideration applicable to Refinery NSPS Ja.[10] These technical corrections and clarifications are addressed in this rulemaking because they also affect sources subject to the amendments to Refinery MACT 1 and 2.

In this section, we provide an overview of the engineering cost analysis used to estimate the additional private expenditures industry may make in order to comply with the following portions of the rule amendments:

- For storage vessels, require fitting controls on affected floating roof storage vessels.
- Work practice standards for the delayed coking units (DCU).
- New work practice requirements for fugitive emissions sources, which include establishing a fenceline concentration, conducting fenceline monitoring, and requiring corrective actions if the fenceline monitoring results indicate that benzene concentrations exceed a specific concentration action level.
- Relief valve monitoring using a system that is capable of identifying and recording the time and duration of each pressure release and of notifying operators that a pressure release has occurred.

[10] The Refinery NSPS J was amended in 2008, following a review of the NSPS. As part of the review, EPA developed separate standards of performance for new process units (NSPS Ja).

- Operating and monitoring requirements for refinery flares used as control devices in refinery MACT 1 and 2 to ensure flares are meeting the emissions limits required by the refinery MACT standards. Owners or operators of flares used as a control device are required to monitor. For flares using steam- or air-assist, monitoring of steam- and/or air-assist rates is also required to determine compliance with the operating limits.
- PM and HCN emissions testing requirements for FCCUs consistent with Refinery NSPS Ja.

For additional discussion of the amendments, in the rule preamble see *Section III.C. What are the final NESHAP amendments pursuant to section 112(d)(2) & (3) for the petroleum refinery source categories?.*

## 3.2 Summary of Final Rule Amendments

### *3.2.1 Storage Vessels*

Storage vessels, also referred to as storage tanks, are used to store liquid and gaseous feedstocks for use in a process, as well as liquid and gaseous products coming from a process. Most storage vessels are designed for operation at atmospheric or near atmospheric pressures. High-pressure vessels are used to store compressed gases and liquefied gases. In the engineering cost analysis for the proposed amendments, fitting controls and monitoring options were identified as advances in practices, processes and control technologies for storage vessels. In the June 2014 proposal, the EPA identified emission reduction options that included: (1) Option 1 -- requiring guidepole controls and other fitting controls for existing external or internal floating roof tanks as required in the Generic MACT for storage vessels (40 CFR part 63, subpart WW) in 40 CFR 63.1063; (2) Option 2 -- Option 1 plus revising the definition of Group 1 storage vessel to include smaller capacity storage vessels and/or storage vessels containing materials with lower vapor pressures; and (3) Option 3 -- Option 2 plus requiring additional monitoring to prevent roof landings, liquid level overfills and to identify leaking vents and fittings from tanks. At proposal, Options 1 and 2 were identified as advances in practices, processes and control technologies because these options are required for similar tanks in some chemical manufacturing MACT standards and are considered technologically feasible for storage vessels at refineries. Option 3 was also identified as an improvement in practices because these monitoring methods have been required for refineries by other regulatory agencies. **In the final rule amendments, EPA is finalizing Option 2 from the June 2014 proposal.**

Based on the engineering cost analysis at proposal, Option 2 was considered to be cost effective and is reflected in the final amendments to revise Refinery MACT 1; the amendment will cross-reference the corresponding storage vessels requirements in the Generic MACT and revise the definition of Group 1 storage vessels.[11] Table 3-1 includes a summary of costs for the proposed options and the final amendment. The annualized cost of capital estimates were determined based on a 7 percent interest rate. The storage vessel-related capital costs were annualized over 15 years. As the storage vessel controls do not require significant on-going operating and maintenance costs, the annualized costs of capital is the primary cost for the storage vessel controls. For further details on the assumptions and methodologies used in this analysis, see the technical memorandum titled Impacts for Control Options for Storage Vessels at Petroleum Refineries, November 14, 2012, Revised September 27, 2015, in Docket ID Number EPA-HQ-OAR-2010-0682.

In addition, negative annualized costs, or recovery credits, were estimated as part of the storage vessel control option. For storage vessels, if a product storage tank has fewer VOC emissions, then there will be more product remaining in the tank that can be sold. The product recovery credit is based on the VOC emissions reductions projected to be achieved at each specific refinery. For storage vessels, these emissions reductions are based on the types and number of tanks present at each refinery, the types of controls currently used for each tank, and the average vapor pressure of the liquid stored. Negative annualized costs introduce the question of why, if these emissions can be reduced profitably using environmental controls, are more producers not adopting the controls in their own economic self-interest. Assuming financially rational producers, standard economic theory suggests that all refineries would incorporate all cost-effective improvements, of which they are aware, without government intervention. This cost analysis is based on the observation that emissions reductions that appear to be profitable, on average, in the analysis have not been adopted by a significant segment of the industry. This observation, often termed the "energy paradox", has been noted to occur in other contexts where consumers and firms appear to undervalue a wide range of investments in energy conservation, even when they pay off over relatively short time periods. We discuss some possible explanations for the apparent paradox in the context of the storage vessel requirements.

First, there may be an opportunity cost associated with the installation of environmental controls (for purposes of mitigating the emissions of pollutants) that is not reflected in the control costs. In the event that the environmental investment displaces other investment in productive capital, the difference between the rate of return on the marginal investment displaced by the mandatory environmental investment is a measure of the opportunity cost of the

[11] The proposed revised definition will include (1) storage vessels with capacities greater than or equal to 20,000 gallons, but less than 40,000 gallons if the maximum true vapor pressure is 1.9 pounds per square inch absolute (psia) or greater and (2) storage tanks greater than 40,000 gallons if the maximum true vapor pressure is 0.75 psia or greater.

environmental requirement to the regulated entity. However, if firms are not capital constrained, there may not be any displacement of investment, and the rate of return on other investments in the industry would not be relevant as a measure of opportunity cost. If firms should face higher borrowing costs as they take on more debt, there may be an additional opportunity cost to the firm. To the extent that any opportunity costs are not added to the control costs, the compliance costs presented above may be underestimated.

A second explanation could be that the average impacts identified in this analysis are not reflective of the true costs compelled by the regulation relative to the controls installed voluntarily. A third explanation for why there appear to be negative cost control technologies that are not generally adopted is imperfect information. If emissions from the refining sector are not well understood, firms may underestimate the potential financial returns to capturing emissions. Finally, the cost from the irreversibility associated with implementing these environmental controls is not reflected in the engineering cost estimates above. It is important to recognize the value of flexibility taken away from firms when requiring them to install and use a particular emissions capture technology. If a firm has not adopted the technology on its own, then a regulation mandating its use means the firm loses the option to postpone investment in the technology in order to pursue alternative investments today, and the option to suspend use of the technology if it becomes unprofitable in the future. Therefore, the full cost of the regulation to the firm is the engineering cost and the lost option value minus the revenues from the sale of the additional recovered product. In the absence of quantitative estimates of this option, the cost estimates for the storage vessel controls may underestimate the full costs faced by the affected firms.

**Table 3-1 Nationwide Emissions Reduction and Cost Impacts of Control Options and Final Amendment for Storage Vessels at Petroleum Refineries (2010$)**

| Control Option | Total Capital Investment (million 2010$) | Total Annualized Costs w/o Recovery Credits (million $/yr) | Recovery Credits (million $/yr) | Total Annual-ized Costs w/ VOC Recovery Credits (million $/yr) | Emissions Reductions, VOC (tpy) | Emissions Reductions, HAP (tpy) | Overall Cost Effectiveness with VOC Recovery Credit ($/ton HAP) |
|---|---|---|---|---|---|---|---|
| 1 | 11.9 | 1.8 | (6.6) | (4.8) | 11,800 | 720 | (6,690) |
| **2 – Final Amendment** | **18.5** | **3.13** | **(8.16)** | **(5.03)** | **14,600** | **910** | **(5,530)** |
| 3 | 36.4 | 9.6 | (9.1) | 0.56 | 16,000 | 1,000 | 560 |

### *3.2.2 Delayed Coking Units*

DCUs use thermal cracking to upgrade heavy feedstocks and to produce petroleum coke. Unlike most other refinery operations which are continuous, DCUs are operated in a semi-batch system. Most DCUs consist of a large process heater, two or more coking drums, and a single product distillation column. Bottoms from the distillation column are heated to near cracking temperatures and the heavy oil is fed to one of the coking drums. As the cracking reactions occur, coke is produced in the drum and begins to fill the drum with sponge-like solid coke material. When one coking drum is filled, the feed is diverted to the second coke drum. The full coke drum is purged and cooled by adding steam and water to the vessel. The initial water added to the vessel quickly turns to steam, and the steam helps to cool and purge organics in the coke matrix. After the coke drum is sufficiently cooled and filled with water in sufficient volumes to cover the coke, the drum is opened, the water drained, and the coke is removed from the vessel using high pressure water. Once the coke is cut out of the drum, the drum is closed, and prepared to go back on-line. A typical coke drum cycle is typically 28 to 36 hours from start of feed to start of feed.

During the reaction process, the DCU is a closed system. When the coke drum is taken off line, the initial steaming process gas is also recovered through the unit's product distillation column. As the cooling cycle continues, the produced steam is sent to a blowdown system to recover the liquids. Refinery MACT 1 standards (40 CFR part 63, subpart CC) define the releases to the blowdown system as the delayed coker vent and these emissions must be controlled following the requirements for miscellaneous process vents. Near the end of the cooling process, a vent is opened on the drum to allow the remaining steam and vapors to be released directly to the atmosphere prior to draining, deheading, and decoking (coke cutting) the coke from the drum. Emissions from DCU occur during this depressuring (commonly referred to as the steam vent) and subsequent decoking steps.

The additional gas collected from the coke drum is expected to go to the closed blowdown system, where the steam is condensed to water and either recycled directly for reuse in the DCU or sent to the sour water system for treatment prior to being reused. The uncondensed gases are typically either (i) sent to the DCU distillation column where they would be recovered in the distillation column overheads as fuel gas, or (ii) directly routed to a nearby process heater or boiler, or discharged to a flare. The uncondensed dry gas is expected to consist primarily of methane (70 percent) with some ethane and propane (5 to 10 percent each). As such, the dry gas recovered from the DCU is expected to have a heating value approximately equivalent to natural gas (approximately 1,000 British thermal units per dry standard cubic foot (Btu/dscf)). Assuming the recovered gas is directed to the distillation column or directly used as fuel, the additional dry gas recovered is expected to offset natural gas purchases. The EPA estimated a dry gas recovery credit using natural gas costs of $5.00/1,000 cubic feet.[12] For additional discussion, see the technical memorandum titled Impact Estimates for Delayed Coking Units, September 12, 2013 in Docket ID Number EPA-HQ-OAR-2010-0682.

Establishing a lower pressure set point at which a DCU owner or operator can switch from venting to an enclosed blowdown system to venting to the atmosphere is the primary control technique identified for reducing emissions from delayed coking operations. Essentially, there is a fixed quantity of steam that will be generated as the coke drum and its contents cool. The lower pressure set point will require the DCU to vent to the closed blowdown system longer, where emissions can be recovered or controlled. This will result in fewer emissions released during the venting, draining and deheading process.

Refinery NSPS Ja establishes a pressure limit of 5 pounds per square inch gauge (psig) prior to allowing the coke drum to be vented to the atmosphere. Based on a review of permit limits and consent decrees, EPA found that coke drum vessel pressure limits have been established and achieved as low as 2 psig. Based on the 2011 ICR responses, there are 75 operating DCU, indicating that the sixth percentile is represented by the fifth-best performing DCU (EPA, 2011). EPA researched permits, consent decrees, refinery ICR responses, and other rules addressing DCU depressurizing limits. In the June 2014 proposal, EPA proposed the MACT floor for DCU decoking operations is to depressure at 2 psig or less prior to venting to the atmosphere for both new and existing sources. EPA received comments on the proposed amendments related to excluding some DCU from the analysis (see the July 22, 2015 Reanalysis of MACT for Delayed Coking Unit Decoking Operations memorandum in Docket ID Number

[12] Refineries purchase natural gas as industrial consumers, and the $5.00/1,000 cubic feet natural gas price used in the recovery credit estimates represents a 5-year average natural gas price for industrial consumers.

EPA-HQ-OAR-2010-0682 for more discussion of the comments). Out of the 75 operating DCU, EPA identified approximately 25 DCU that either currently operate or are required to operate by venting to the atmosphere only after the coke drum vessel pressure has reached 2 psig or less. See Table 2 of the July 22, 2015 Reanalysis of MACT for Delayed Coking Unit Decoking Operations memorandum for more details on these DCU. Based on a reanalysis of the available data, EPA concludes that for existing sources the MACT floor emissions limit is 2 psig, on average, and for new sources the MACT floor emission limit is 2.0 psig on a per coke drum venting event basis. For existing sources, the high incremental cost of going from a 2 psig 60-event average limit to a 2.0 psig for each venting event limit suggests that it is not cost-effective to go beyond the MACT floor emissions limit for existing sources. Therefore, for existing sources the MACT floor is 2 psig determined on a rolling 60-event average limit basis. **In the final rule amendments, for existing sources EPA is finalizing 2 psig on a rolling 60-event average limit basis, and for new sources EPA is finalizing 2.0 psig on a per coke drum venting event basis.**

At proposal, EPA also considered control options beyond the floor level of 2 psig to determine if additional emissions reductions could be cost effectively achieved. EPA considered a control option that allowed atmospheric venting only after the DCU vessel pressure reached 1 psig or less, since some facilities reported in the 2011 ICR depressurizing to that level prior to venting (EPA, 2011). EPA determined that there are several technical difficulties associated with establishing a pressure limit at this lower level. EPA also considered whether there were means to connect the bottom of the coke drum to a large diameter "hose" so that the drained water and/or the coke cutting slurry could be discharged from the DCU and enter the coke pit in a submerged fill manner. However, EPA could identify no commercially available equipment to connect the coke drum to the coke pit. Because these options were either not technically feasible or equipment was not commercially available, EPA did not estimate costs.

For existing sources, EPA assumed all DCU that reported a "typical drum pressure prior to venting" of more than 2 psig would install and operate a steam ejector system to reduce the coke drum pressure to 2 psig prior to venting to atmosphere or draining. EPA assumed the steam ejectors would be sufficient to achieve a 67 percent emission reduction and assigned capital costs based on the recent installation of a steam ejector system. If a DCU would need more than 67 percent emissions reduction then the capital costs were projected to be twice the capital investment for steam ejectors to account for the use of steam ejector systems along with additional modifications to improve the blow down system capacity. EPA anticipates that new DCU sources can be built with a closed blowdown system designed to achieve a 2 psig vessel pressure with no significant increase in capital or operating costs of the new DCU.

Costs and emissions reductions were evaluated on a DCU-specific basis using the data reported by petroleum refineries in the detailed 2011 ICR responses, along with vendor quotes obtained in 2011 (EPA, 2011). The cumulative nationwide costs for the final amendments calculated for the petroleum refining industry are summarized in Table 3-2 and Table 3-3**.** Annualized costs of capital estimates were determined based on a 7 percent interest rate. The DCU capital costs were annualized over 15 years. In addition to the VOC and HAP emissions reductions reported in Tables 3-2 and 3-3, the requirements for DCU control are estimated to result in approximately 8,700 metric tons of methane emissions reductions. For additional discussion, see the technical memorandum titled Impact Estimates for Delayed Coking Units, September 12, 2013, and the technical memorandum titled Reanalysis of MACT for Delayed Coking Unit Decoking Operations, July 22, 2015 in Docket ID Number EPA-HQ-OAR-2010-0682.

**Table 3-2 Nationwide VOC Impacts for Delayed Coking Unit Control (2010$)**

| Control Option | Total Capital Investment (million 2010$) [13] | Total Annualized Costs w/o Recovery (million $/yr) | Recovery Credits (million $/yr) | Total Annualized Costs w/ Recovery (million $/ yr) | Emissions Reduction, VOC (tpy) | Cost Effectiveness ($/ton VOC reduced) |
|---|---|---|---|---|---|---|
| **Existing Sources -- 2 psig, 60-event average** | **81.0** | **14.5** | **(2.8)** | **11.7** | **2,060** | **5,680** |
| **New Sources** –2.0 psig per event | 92.0 | 16.2 | (2.9) | 13.3 | 2,180 | 6,110 |

[13] The technical memo entitled Impact Estimates for Delayed Coking Units includes the following note of clarification: “Although the control cost estimates for delayed coking units were developed from 2011 vendor quotes, the impacts for other petroleum refinery sources are reported in 2010 dollars to be consistent with other cost estimates developed for other Refinery MACT 1 emission sources. Given the low inflation across this time period, it was assumed that the delayed coking unit costs

**Table 3-3 Nationwide HAP Impacts for Delayed Coking Unit Control (2010$)**

| Control Option | Total Capital Investment (million 2010$) | Total Annualized Costs w/o Recovery (million $/yr) | Recovery Credits (million $/yr) | Total Annualized Costs w/ Recovery (million $/ yr) | Emissions Reduction, HAP (tpy) | Cost Effectiveness ($/ton HAP reduced) |
|---|---|---|---|---|---|---|
| **Existing Sources -- 2 psig, 60-event average** | **81.0** | **14.5** | **(2.8)** | **11.7** | **413** | **28,400** |
| **New Sources** –2.0 psig per event | 92.0 | 16.2 | (2.9) | 13.3 | 436 | 68,700 |

### *3.2.3 Fenceline Monitoring*

Certain emissions sources, such as fugitive leaks from equipment and wastewater collection and treatment systems, are inherently difficult to quantify with methods currently available. In general, uncertainties in emissions estimates result from:

- Exclusion of nonroutine emissions;
- Omission of sources that are unexpected, not measured, or not considered part of the affected source, such as emissions from process sewers, wastewater systems, or other fugitive emissions;
- Improper characterization of sources for emissions models and emissions factors; and
- Inherent uncertainty in emissions estimation methodologies.

In 2009, the EPA conducted a year-long diffusive tube monitoring pilot project at the fenceline of Flint Hills West Refinery in Corpus Christi, Texas. The study concluded that the modeled-derived concentrations are significantly lower than the actual measured values at virtually every point along the fenceline. On average, the measured values were several times higher than the modeled values. Although EPA would not expect the values to be identical, such a significant difference is an indicator that emissions may, in fact, be far more significant than accepted methodologies and procedures can predict.

Measurement of the concentration of expected pollutants at the fenceline provides an indication of the uncertainty associated with emissions estimates for all near ground-level sources, including fugitives. EPA reviewed the available literature and identified several

developed from the 2011 vendor quotes could be used without correction to estimate the delayed coking units control costs in 2010 dollars."

different methods for measuring fugitive emissions around the fenceline of a petroleum refinery. These methods include: (1) passive diffusive tube monitoring networks; (2) active monitoring station networks; and (3) open path monitoring systems. As a result of the year-long fenceline monitoring pilot project at Flint Hills West Refinery in Corpus Christi, EPA found the passive diffusive tube monitoring technology to be capable of providing cost-effective, relatively robust monitoring data.

Average annual costs were estimated for a ten-year period (the useful life of the analytical equipment is expected to be ten years, according to the analytical equipment manufacturer representatives) and assumed an annualized cost of capital based on a 7 percent interest rate. The initial costs include the cost of purchasing and installing the monitoring stations, collecting the samples, and performing the analyses for the first year. Initial costs also include the cost of purchasing a gas chromatograph, a thermal desorption unit with an autosampler, and the diffusive tubes and caps. Analytical equipment cost estimates were developed from vendor quotes, which included both the cost of the analytical equipment and materials, as well as man-hour estimates for performing the analyses. Recurring costs include the cost (man-hours) for collecting the samples and the cost of analyzing the samples (and any materials consumed).

**In the final rule amendments, EPA is finalizing a fenceline monitoring work practice standard.** Reflecting comments received on the June 2014 proposal, Table 3-4 presents updated nationwide cost estimates of the final amendment of passive diffusive tube monitoring technology, along with the cost estimates for the two additional monitoring locations. To generate the estimates, it was assumed that refineries with crude refining capacity of less than 125,000 barrels per day would fall into the small size (less than 750 acres); refineries with crude refining capacity greater than or equal to 125,000 barrels per day and less than 225,000 barrels per day would fall into the medium size facility range (greater than or equal to 750 and less than 1,500 acres); and refineries with crude throughput of greater than or equal to 225,000 barrels per day would fall into the large facility size (greater than or equal to 1,500 acres). The nationwide costs included for the final amendments assume that all facilities would elect to purchase the equipment necessary to perform the analysis in-house. For additional discussion, see the technical memorandum titled Fenceline Monitoring Technical Support Document, January 17, 2014, and the technical memorandum titled Fenceline Monitoring Impact Estimates for Final Rule, June 4, 2015, in Docket ID Number EPA-HQ-OAR-2010-06.

**Table 3-4 Nationwide Costs (in 2010$) for Fenceline Monitoring at Petroleum Refineries**

| Refinery Area Size | Number of Refineries | Number of Monitoring Sites per Refinery | Capital Costs for All Refineries ($) | Annualized Cost ($/yr) |
|---|---|---|---|---|
| **Final Amendment -- Passive Diffusive Tube Monitoring Station Network** | | | | |
| **Small (< 750 acres)** | **84** | **12** | **7,279,000** | **3,444,000** |
| **Medium (≥ 750 and < 1,500 acres)** | **27** | **18** | **2,410,000** | **1,285,000** |
| **Large (≥1,500 acres)** | **31** | **24** | **2,817,000** | **1,628,000** |
| **Total** | **142** | **2,238** | **12,500,000** | **6,360,000** |
| Option 2 - Active Monitoring Station Network | | | | |
| Small (< 750 acres) | 84 | 12 | 11,090,000 | 16,300,000 |
| Medium (≥ 750 and < 1,500 acres) | 27 | 18 | 4,130,000 | 6,930,000 |
| Large (≥1,500 acres) | 31 | 24 | 5,390,000 | 9,900,000 |
| Total | 142 | 2,238 | 20,600,000 | 33,100,000 |
| Option 3 - Open Path Monitoring Network | | | | |
| Total | 142 | 568[14] | 71,000,000 | 45,600,000 |

### *3.2.4 Relief Valve Monitoring*

Relief valve releases vented directly to the atmosphere are caused by malfunctions, and emissions vented to the atmosphere by relief valves can contain HAP emissions. Using CAA Section 112(d)(2) and (3), the June 2014 proposal specified that relief valves in organic HAP service may not discharge to the atmosphere. EPA received comments on the proposed prohibition of relief valve releases to the atmosphere.

[14] For the monitoring approach, EPA assumed 4 monitoring stations per refinery – 142 refineries * 4 monitoring stations = 568 total monitoring sites.

In response to the comments, EPA considered two basic options -- Option 1 was to maintain the prohibition on pressure relief valve (PRV) releases as proposed, and Option 2 was a work practice standard for PRV releases based on the general work practice standards outlined in the July 30, 2015 memorandum Pressure Relief Device Control Option Impacts for Final Refinery Sector Rule in Docket ID Number EPA-HQ-OAR-2010-0682.

There are 15,100 atmospheric PRV at U.S. petroleum refineries. If many of the refinery flares are near their hydraulic load capacity based on the processes already connected to the flares, then under Option 1 requiring all of these PRV to be piped to a control device would require the installation of new flares. It is difficult to know how many of the existing PRV can be easily controlled or how many existing PRV would be controlled by a single new flare. To estimate costs, EPA assumed 60 percent of the PRV could be piped to existing controls at minimal costs and the other 40 percent would have to be piped to new flares. Based on these assumptions, 151 new flares would be needed, or approximately one new flare per refinery. At a capital cost of $2 million for each new flare, EPA estimated that the capital cost of Option 1 would exceed $300 million. The new additional flares would operate at idle conditions for the vast majority of time and require a minimal natural gas or refinery fuel gas flow to prevent oxygen ingress. Considering this additional fuel need, EPA estimated the annual operating cost for these new flares would be $12 million.

Under Option 2, the cost estimate for the work practice standard was based on implementing three redundant prevention measures, conducting root cause analysis (RCA) for releases, and implementing corrective actions. EPA estimated the cost of implementing prevention measures would be $4,000 per PRV and the cost of RCA/corrective action would be $5,000 per release event. Many atmospheric PRV would be expected to already have redundant prevention measures based on process hazard analyses required under other programs (e.g., OSHA), so EPA assumed only 30 percent of PRV that would be subject to the standard would need to implement additional prevention measures. We also included $800 for monitors for release events for those PRV subject to the work practice standard requirements based on the average costs estimated for the proposal analysis. **In the final rule amendments, EPA is finalizing Option 2 -- a work practice standard for PRV releases.**

Table 3-5 summarizes the cost impacts estimated for Options 1 and 2. Annualized cost of capital estimates were determined based on a 7 percent interest rate and a 10-year equipment life. The nationwide capital cost of the work practice standard in the final amendments is $11.1 million and the annualized capital cost is $3.3 million per year (2010$). For additional discussion of the relief valve monitoring amendments, see the technical memorandum titled Impacts for Equipment Leaks at Petroleum Refineries, December 19, 2013, and the technical memorandum titled Pressure Relief Device Control Option Impacts for Final Refinery Sector Rule, July 30, 2015, in Docket ID Number EPA-HQ-OAR-2010-0682.

**Table 3-5 Nationwide Costs for Atmospheric Pressure Relief Valves (2010$)**

| Option | Total Capital Cost (million 2010$) | Total Annualized Cost (million $/yr) |
|---|---|---|
| Option 1 – Prohibition on Atmospheric PRV Releases | 302 | 41 |
| **Option 2 -- Final Amendment – Work Practice Standard** | **11.1** | **3.3** |

### *3.2.5 Flare Combustion Efficiency*

All of the requirements for flares operating at petroleum refineries are intended to ensure compliance with the Refinery MACT 1 and 2 standards when using a flare as an air pollution control device. Refinery MACT 1 and 2 reference the flare requirements in the General Provisions[15], which require a flare used as an air pollution control device to operate with a pilot flame present at all times and to have a minimum waste gas heating value.[16] In the June 2014 proposal, EPA proposed to remove the cross-reference to the General Provisions and include requirements directly in Refinery MACT 1 and 2 that address the operation of flares to achieve good combustion efficiency. The proposal required that flares operate with a pilot flame at all times and be continuously monitored for using a thermocouple or any other equivalent device.

[15] General Provisions are the general provisions under 40 CFR Part 63 for *National Emissions Standards for Hazardous Pollutants for Source Categories.* Available at <http://www.gpo.gov/fdsys/pkg/CFR-2011-title40-vol9/xml/CFR-2011-title40-vol9-part63.xml>.

[16] Pilot flames are proven to improve flare flame stability; even short durations of an extinguished pilot could cause a significant reduction in flare destruction efficiency.

EPA also proposed a new operational requirement to use automatic relight systems for all flare pilot flames and to add a requirement that a visible emissions test be conducted each day and whenever visible emissions are observed from the flare using an observation period of 5 minutes and EPA Method 22 of 40 CFR part 60, Appendix A-7. EPA also proposed a requirement to operate the flare tip velocity less than 60 feet per second or at a lower value depending on the heat content of the gas flared. Finally, EPA proposed operating limits in the combustion zone that also included detailed monitoring requirements to determine these operating parameters either through continuous parameter monitoring systems or grab sampling, detailed calculation instructions for determining these parameters on a 15-minute block average, and detailed recordkeeping and reporting requirements.

EPA received numerous comments regarding the proposed requirements to have the flare tip velocity and visible emissions limits apply at all times. The comments indicated that flares have two different design capacities -- a “smokeless capacity” to handle normal operations and typical process variations and a “hydraulic load capacity” to handle very large volumes of gases discharged to the flare, typically as a result of emergency shutdown scenarios. The comments indicated that this is inherent in all flare designs and it has not previously been an issue because the flare operating limits did not apply during periods of startup, shutdown and malfunction. However, if flares must be operated in the smokeless capacity regime at all times, even during periods of emergency releases, the commenters suggested that refineries would have to quadruple the number of flares at each refinery to control an event that may occur once every 2 to 5 years.

In response to the comments, EPA assessed two basic options -- Option 1 would be to require the visible emissions and velocity operating limit to apply at all times as proposed, and Option 2 would require a work practice standard for periods when the flow to the flare exceeds the smokeless capacity of the flare. Owners or operators of flares would establish the smokeless capacity of the flare based on design specification of the flare. Below this smokeless capacity, the velocity and visible emissions standards would apply as proposed in June 2014. Above the smokeless capacity, flares would be required to perform a root cause and corrective action analysis to identify and implement prevention measures to prevent the recurrence of a similarly caused event. Multiple events from the same flare in a given time period (3 to 5 years) would be a violation of the work practice standard; however, *force majeure* events would not be included in the event count for this requirement.

There are 510 flares at U.S. petroleum refineries as reported in the 2011 Petroleum Refinery Information Collection Request (ICR) (EPA, 2011). For Option 1, EPA estimated that 1,000 to 2,000 new flares may be needed to make sure all flaring events, including whole plant emergency shutdowns, occur without smoking. Assuming a total of 1,500 flares are needed at approximately $2 million per flare, the estimated capital costs of applying the velocity and visible emissions limit at all times under Option 1 would be approximately $3 billion. The annualized total cost would be approximately $415 million.

To address periods of emergency flaring, for Option 2 (the alternative work practice standard) there would be a one-time cost for developing a flare management plan or supplementing an existing flare management plan. EPA estimated this one-time cost to be $7,500 per flare on average and attributed this cost to all 510 flares for a total estimated cost of $3.8 million. EPA annualized this one-time cost over a 15-year period to estimate the annual cost of the flare management plan. EPA also estimated each root cause analysis conducted under the work practice standard would cost about $5,000 (i.e., $5,000 per event). At a frequency of one event every 4 years, on average, for a given flare, the annual cost per flare would be $1,500/year/flare. The root cause and corrective action analysis is designed to limit the frequency and magnitude of releases. If the frequency of events occurring is shifted from once every 4 years to once every 6 years, the annual cost would approach $1,000/year/flare. EPA estimated the annual average root cause and corrective action analysis costs over the long term would be about $1,250/year/flare and applied this cost to all 510 flares for a total annual cost of $637,500. These annualized costs associated with the flare management plan and the annual average root cause and corrective action analysis cost were added together for a total annualized cost of $900,000. **In the final rule amendments, EPA is finalizing the work practice standard for periods when the flow to the flare exceeds the smokeless capacity of the flare.** Table 3-6 provides a summary of total capital and annualized cost for Option 1 and Option 2, the final amendment.

**Table 3-6 Summary of Impact of Visible Emissions and Velocity Limit Options for High Flow Events (All Flares at Major Source Refineries) (2010$)**

| Control Alternative Description | Total Capital Investment (million$) | Total Annualized Cost (million $/yr) |
|---|---|---|
| Option 1 – Visible emissions and velocity operating limit apply at all times, as proposed | 3,060 | 415 |
| **Option 2 -- Final Amendment –<br>Work practice standard for events exceeding smokeless capacity** | **3.8** | **0.90** |

**For flare monitoring requirements, EPA is finalizing new operational requirements related to combustion zone gas properties with revisions from the June 2014 proposal.** The EPA is finalizing requirements that flares meet a minimum operating limit of 270 BTU/scf NHVcz on a 15-minute average, as proposed, but allowing refiners to use a corrected heat content of 1,212 BTU/scf for hydrogen to demonstrate compliance with this operating limit. EPA also proposed two separate sets of limits, one being more stringent if an olefins/hydrogen mixture was present in the waste gas. For each set of limits, EPA proposed three different alternative combustion zone operating limits and that these limits be determined on a 15-minute "feed-forward" block average approach. Based on comments received, **for the final amendments EPA is simplifying the compliance approach to a single set of limits based only on the combustion zone net heating value. As proposed, EPA is finalizing a requirement that refiners characterize the composition of waste gas, assist gas, and fuel to demonstrate compliance with the operational requirements.**

**Also as proposed EPA is finalizing a burden reduction option to use grab sampling every 8 hours rather than continuous vent gas composition or heat content monitors.** In response to comments, EPA is also finalizing provisions to conduct limited initial sampling and process knowledge to characterize flare gas composition for flares in "dedicated" service as an alternative to collecting grab sampling during each specific event. **EPA is finalizing the requirement for daily visible emissions observations as proposed, but, based on public comments, EPA is allowing owners and operators to use video surveillance cameras to**

**demonstrate compliance with the visible emissions limit as an alternative to the daily visible emissions observations.**

EPA does not know the specific timing of how regulated firms will expend resources on new environmental compliance activities.  EPA annualized the capital costs in Table 3-7. Industry costs submitted to EPA through consent decrees were used as the primary source of cost estimation.  These costs included all installation and ancillary costs associated with the installation of the monitors (i.e., analyzer shelters and electrical connections).  Costs were estimated for each flare for a given refinery, considering operational type and current monitoring systems already installed on each individual flare.  Costs for any additional monitoring systems needed were estimated based on installed costs received from petroleum refineries and, if installed costs were unavailable, costs were estimated based on vendor-purchased equipment. Table 3-7 provides detailed cost information for the flare monitoring requirements, and Table 3-8 provide total costs for the flare monitoring requirements and work practice standards for events exceeding smokeless capacity.  For additional discussion, see the technical memorandum titled Petroleum Refinery Sector Rule:  Flare Impact Estimates, January 16, 2014 and the technical memorandum titled Flare Control Option Impacts for Final Refinery Sector Rule, July31, 2015, in Docket ID Number EPA-HQ-OAR-2010-0682.  The specific cost data collected for the flare cost estimates are provided in Attachment 3 to the January 16, 2014 technical memorandum. See Attachment 3 for details on the assumptions made for equipment life and interest rate.

**Table 3-7 Detailed Costs of Flare Monitoring Requirements (2010$)**

| Monitoring Equipment | Total Capital Investment ($/flare)* | Total Annualized Cost ($/year/flare)* | # of Flares | Total TCI ($) | Total TAC ($/year) | Notes[17] |
|---|---|---|---|---|---|---|
| Calorimeter | $105,000 | $30,000 | 85 | $8,925,000 | $2,550,000 | **85 flares** (Table 9) Column labeled -- Number of flares needing to install a new heat content monitor, All.<br><br>Row labeled -- Total no. of flares. |
| Steam Flow/Controls | $684,000 | $124,300 | 190 | $129,960,000 | $23,617,000 | **190 flares (**Table 3) Column labeled -- Number of Routine Flow Flares, All;<br><br>Rows -- Steam-Assisted (228) – Air-Assisted (38) = 190 |
| Air Flow/Controls | $164,000 | $52,000 | 37[18] | $6,070,000 | $1,920,000 | **38 flares (**Table 3) Column labeled -- Number of Routine Flow Flares, All;<br><br>Row labeled -- Air-Assisted (38) |
| Supplemental Natural Gas | $0 | $100,030 | 190 | $0 | $19,010,000 | **190 flares (**Table 3) Column labeled -- Number of Routine Flow Flares, All;<br><br>Rows -- Steam-Assisted (228) – Air-Assisted (38) = 190 |
| Steam Savings | $0 | -$56,470 | 190 | $0 | -$10,730,000 | **190 flares (**Table 3) Column labeled -- Number of |

[17] The tables referenced are located in the technical memo entitled "Petroleum Refinery Sector Rule: Flare Impact Estimates", January 16, 2014, in Docket ID Number EPA-HQ-OAR-2010-0682.

[18] The number of flares was updated and presented in the technical memo entitled "Flare Control Option Impacts for Final Refinery Sector Rule", June 12, 2015.

| Monitoring Equipment | Total Capital Investment ($/flare)* | Total Annualized Cost ($/year/flare)* | # of Flares | Total TCI ($) | Total TAC ($/year) | Notes[17] |
|---|---|---|---|---|---|---|
| | | | | | | Routine Flow Flares, All;<br><br>Rows -- Steam-Assisted (228) – Air-Assisted (38) = 190 |
| Engineering Cost Calculations | $7,000 | $13,160 | 267 | $1,869,000 | $3,513,720 | **267 flares (510 flares – 243 flares)**<br>**Table 3**: Column labeled – Total Number of Flares, All;<br>Row labeled – Total No. of Flares (510)<br><br>**Table 9**: Column labeled – Number of Routine flares that do not have full FGRS, All<br><br>Row labeled – Total No. of Flares (243) |
| **Total** | N/A | N/A | N/A | **$156,000,000** | **$45,600,000** | N/A |

* Costs are located in Table 7. *Summary of Flare Monitoring Equipment and Material Costs (2010$)* in the technical memo entitled "Petroleum Refinery Sector Rule: Flare Impact Estimates", January 16, 2014, in Docket ID Number EPA-HQ-OAR-2010-0682.

N/A = Not applicable

**Table 3-8 Nationwide Costs for Requirements for Flare Monitoring and Visible Emissions and Velocity Limit for High Flow Events (2010$)**

| | Total Capital Cost (million 2010$) | Total Annualized Cost (million $/yr) |
|---|---|---|
| **Flare Monitoring Requirements** | **156** | **45.6** |
| **Work Practice Standards for Visible Emissions and Velocity Limit for High Flow Events** | **3.8** | **0.90** |
| **Total** | **160** | **46.5** |

### *3.2.6 FCCU Testing*

Under Refinery MACT 2, an initial emissions source performance demonstration is required to show that the FCCU is compliant with the emissions limits selected by the refinery owner or operator. The performance test is a one-time requirement; additional performance tests are only required if the owner or operator elects to establish new operating limits, or to modify the FCCU or control system in such a manner that could affect the control system's performance.

Currently, the Refinery MACT 2 does not include periodic performance tests for any FCCU. The lack of any ongoing performance test requirements is inconsistent with developments in practices for ensuring ongoing compliance with emission limits. For the final amendments, we are requiring an FCCU emissions source performance tests once every 5 years (i.e., once per title V permit period) for all FCCU subject to Refinery MACT 2 for PM and HCN. The nationwide annual cost of this additional testing requirement for the FCCU is estimated to be, on average, $400,000 per year.

## 3.3 Summary of Costs of Rule Amendments

The total capital investment cost of the final amendments and enhanced monitoring provisions is estimated at $283 million -- $112 million from the final amendments and $171 million from standards to ensure compliance. The annualized costs are estimated to be approximately $63.2 million, which includes an estimated $11 million credit for recovery of lost product, some operation and maintenance costs, and the annualized cost of capital. EPA does not know the specific timing of how regulated firms will expend resources on new environmental compliance activities. EPA annualizes the capital costs in Table 3-9, generally over a period of between 10 and 15 years.

The total capital investment cost of the final amendments associated with requirements for storage vessels, delayed coking units, and fugitive emissions monitoring is estimated at $112 million. We estimate annualized costs associated with those final requirements to be approximately $13 million, which includes the estimated $11 million credit for recovery of lost product and the annualized cost of capital. The requirements for storage vessels would result in additional capital costs of $18.5 million and a negative annualized cost of $5.03 million per year. The requirements for DCUs would result in additional capital costs of $81 million and an annualized cost of $11.7 million per year, and the requirements associated with fenceline monitoring would result in additional capital costs of $12.5 million and an annualized cost of $6.36 million per year. The final amendments will achieve a nationwide HAP emission reduction of about 1,323 tons/year with a concurrent reduction in VOC emissions of about

16,660 tons/year.  The top section of Table 3-9 below summarizes the cost and emissions reduction impacts of these final standards and amendments.

In addition, the final amendments to include flare monitoring and operational requirements to ensure compliance would result in an additional total nationwide capital cost of $171 million and an annualized cost of $50.2 million.  The requirements for relief valve monitoring would result in additional capital costs of $11.1 million and an annualized cost of $3.3 million per year.  The requirements for flare monitoring would result in additional capital costs of $160 million and an annualized cost of $46.5 million per year.  The requirements also include requirements for PM emissions source performance tests at least once every five years (once per title V permit period) for the FCCUs at existing sources. The nationwide annual cost of this additional requirement for all FCCUs is projected to be, on average, $400,000 per year.  The bottom section of Table 3-9 below summarizes the cost impacts of these final standards and amendments.

We were not able to estimate (i) the costs, product recovery credits, or emissions reductions associated with any root cause analysis and corrective action taken in response to the final amendments for fugitive emissions monitoring and source performance testing at the FCCUs, or (ii) emissions reductions associated with corrective action taken in response to relief valve monitoring and flare monitoring.  As such, these estimates are not included in Table 3-9. The operational and monitoring amendments for flares at refineries have the potential to reduce excess emissions from flares by up to approximately 3,900 tons per year of HAP and 33,000 tons per year of VOC.  These requirements also have the potential to reduce methane emissions by 25,800 metric tons per year while increasing emissions of carbon dioxide ($CO_2$) and nitrous oxide by 267,000 metric tons per year and 2 metric tons per year, respectively, yielding a net reduction in GHG emissions of 377,000 metric tons per year of $CO_2$ equivalent.[19]

[19] For additional discussion, see Section 4, Table 5 in the technical memorandum titled Flare Control Option Impacts for Final Refinery Sector Rule, June 12, 2015, in Docket ID Number EPA-HQ-OAR-2010-0682.

**Table 3-9 Emissions Sources, Points, and Controls Included in Final Amendments**

| Affected source | Total capital investment ($ million) | Total annualized cost without credit ($ million/ year) | Product recovery credit ($ million/ year) | Total annualized costs ($ million/ year) | VOC emission reductions (tpy) | Cost effective-ness ($/ton VOC) | HAP emission reductions (tpy) | Cost effective-ness ($/ton HAP) |
|---|---|---|---|---|---|---|---|---|
| Storage vessels | 18.5 | 3.13 | (8.16) | (5.03) | 14,600 | (345) | 910 | (5,530) |
| Delayed coking units [a] | 81.0 | 14.5 | (2.8) | 11.7 | 2,060 | 5,680 | 413 | 28,330 |
| Fugitive Emissions (Fenceline Monitoring) | 12.5 | 6.36 | --- | 6.36 [b] | --- | --- | --- | --- |
| Subtotal | 112.0 | 24.0 | (11.0) | 13.0 | 16,660 | 780 | 1,323 | 9,830 |
| | | | | | | | | |
| Relief Valve Monitoring | 11.1 | 3.3 | --- | 3.3 | --- | --- | --- | --- |
| Flare Monitoring | 160.0 | 46.5 | --- | 46.5 [c] | --- | --- | --- | --- |
| FCCU Testing | --- | 0.40 | --- | 0.40 [d] | --- | --- | --- | --- |
| Subtotal | 171.1 | 50.2 | --- | 50.2 | --- | --- | --- | --- |
| | | | | | | | | |
| **Total** | **283** | **74.2** | **(11.0)** | **63.2** | **16,660** | **---** | **1,323** | **---** |

Note: The cost estimates are in 2010$.

[a] In addition to the VOC and HAP emissions reductions, the requirements for the delayed coking units are estimated to result in approximately 8,700 metric tons of methane emissions reductions.
[b] Any corrective actions taken in response to the fugitive emissions fenceline monitoring program will result in additional emissions reductions and additional costs, and these are not included in the results.
[c] Any corrective actions taken in response to the flare monitoring requirements may result in additional emissions reductions and additional costs, and these are not included in the results.
[d] Any corrective actions taken in response to PM emissions source performance tests for the fluid catalytic cracking units may result in additional emissions reductions and additional costs, and these are not included in the results.

## 3.4 References

U.S. Environmental Protection Agency (2011). Petroleum Refinery Information Collection Request (ICR), April 2011. OMB Control Number is 2060-0657. More information available at <https://refineryicr.rti.org/>

# 4 ECONOMIC IMPACT ANALYSIS AND DISTRIBUTIONAL ASSESSMENTS

## 4.1 Introduction

This section includes three sets of analyses:

- Market Analysis
- Employment Impacts
- Small Business Impacts Analysis

## 4.2 Market Analysis

EPA performed a series of single-market partial equilibrium analyses of national markets for five major petroleum products to provide a partial measure of the economic consequences of the regulatory options. With the basic conceptual model described below, we estimated how the regulatory program affects prices and quantities for motor gasoline, jet fuel, distillate fuel oil, residual fuel oil, and liquefied petroleum gases which, when aggregated, constitute a large proportion of refinery production in the United States. We also conducted an economic welfare analysis that estimates the consumer and producer surplus changes associated with the regulatory program. The welfare analysis identifies how the regulatory costs are distributed across two broad classes of stakeholders, consumers and producers, for the five products under evaluation. Because we do not have data on changes in refinery utilization rates, the market analysis does not address costs associated with loss in producer surplus due to potentially lower utilization rates that may result from the final standards.

### *4.2.1 Market Analysis Methods*

The national compliance cost estimates are often used to approximate the welfare impacts of the rule. However, in cases where the engineering costs of compliance are used to estimate welfare impacts, the burden of the regulation is typically measured as falling solely on the affected producers who experience a profit loss exactly equal to these cost estimates. Thus, the entire loss is a change in producer surplus with no change (by assumption) in consumer surplus, because no changes in price and consumption are estimated. This is typically referred to as a "full-cost absorption" scenario in which all factors of production are assumed to be fixed and firms are unable to adjust their output levels when faced with additional costs. In contrast, EPA's economic analysis builds on the engineering cost analysis and incorporates economic theory related to producer and consumer behavior to estimate changes in market conditions.

The partial equilibrium models use a common analytic expression to analyze supply and demand in a single market (Berck and Hoffmann, 2002; Fullerton and Metcalf, 2002) and follows EPA guidelines for conducting an EIA (EPA, 2010). We illustrate our approach for estimating market-level impacts using a simple, single partial equilibrium model. The method involves specifying a set of nonlinear supply and demand relationships for the affected market, simplifying the equations by transforming them into a set of linear equations, and then solving the equilibrium system of equations (see Fullerton and Metcalfe (2002) for an example).

First, we consider the formal definition of the elasticity of supply, $q_s$, with respect to changes in own price, *p*, where $\varepsilon_s$ represents the market elasticity of supply:

$$\varepsilon_s = \frac{dq_s / q_s}{dp / p} \tag{4.1}$$

Next, we can use "hat" notation to transform Eq. 1 to proportional changes and rearrange terms:

$$\hat{q}_s = \varepsilon_s \hat{p} \tag{4.1a}$$

where $\hat{q}_s$ equals the percentage change in the quantity of market supply, and $\hat{p}$ equals the percentage change in market price. As Fullerton and Metcalfe (2002) note, we have taken the elasticity definition and turned it into a linear behavioral equation for the market we are analyzing.

To introduce the direct impact of the amendments, we assume the per-unit cost associated with the amendments, *c*, leads to a proportional shift in the marginal cost of production $\left(mc\right)$. The per-unit costs are estimated by dividing the total estimated annualized engineering costs accruing to producers within a given product market by the baseline national production in that market. Under the assumption of perfect competition (e.g., price equaling marginal cost), we can approximate this shift at the initial equilibrium point as follows:

$$mc = \frac{c}{mc_0} = \frac{c}{p_0}. \tag{4.1b}$$

The with-regulation supply equation can now be written as

$$\hat{q}_s = \varepsilon_s (\hat{p} - mc) \ . \tag{4.1c}$$

Next, we can specify a demand equation as follows:

$$\hat{q}_d = \eta_d \hat{p} \tag{4.2}$$

where

$\hat{q}_d$ = percentage change in the quantity of market demand,

$\eta_d$ = market elasticity of demand, and

$\hat{p}$ = percentage change in market price.

Finally, we specify the market equilibrium conditions in the affected market. In response to the exogenous increase in production costs, producer and consumer behaviors are represented in Eq. 4-1a and Eq. 4-2, and the new equilibrium satisfies the condition that the change in supply equals the change in demand:

$$\hat{q}_s = \hat{q}_d \,. \tag{4.3}$$

We now have three linear equations and three unknowns ( $\hat{p}$ , $\hat{q}_d$ , and $\hat{q}_s$ ), and we can solve for the proportional price change in terms of the elasticity parameters ( $\varepsilon_s$ and $\eta_d$ ) and the proportional change in marginal cost:

$$\begin{aligned}
\varepsilon_s\left(\hat{p} - mc\right) &= \eta_d \hat{p} \\
\varepsilon_s \hat{p} - \varepsilon_s mc &= \eta_d \hat{p} \\
\varepsilon_s \hat{p} - \eta_d \hat{p} &= \varepsilon_s mc \\
\hat{p}\left(\varepsilon_s - \eta_d\right) &= \varepsilon_s mc \\
\hat{p} &= \frac{\varepsilon_s}{\varepsilon_s - \eta_d} mc
\end{aligned} \tag{4.4}$$

Given this solution, we can solve for the proportional change in market quantity using Eq. 4-2.

The change in consumer surplus in the affected market can be estimated using the following linear approximation method:

$$\Delta cs = -\left(q_1 \times p\right) + \left(0.5 \times \Delta q \times \Delta p\right) \tag{4.5}$$

where $q_1$ equals with-regulation quantities produced. As shown, higher market prices and reduced consumption lead to welfare losses for consumers.

For affected supply, the change in producer surplus can be estimated with the following equation:

$$\Delta ps = \left(q_1 \times \Delta p\right) - \left(q_1 \times c\right) - \left(0.5 \times \Delta q \times \left(\Delta p - c\right)\right). \tag{4.6}$$

Increased regulatory costs and output declines have a negative effect on producer surplus, because the net price change $\left(\Delta p - c\right)$ is negative. However, these losses are mitigated, to some degree, as a result of higher market prices.

### *4.2.2 Model Baseline*

Standard EIA practice compares and contrasts the state of a market with and without the regulatory policy. EPA selected 2018 as the baseline year for the analysis and collected petroleum product price and quantity forecast information from the Energy Information Administration's 2014 Reference Case Annual Energy Outlook (EIA, 2014b). Baseline data are reported in Table 4-1. Annual Energy Outlook (AEO) reports the quantity of petroleum products produced in terms of barrels, while the price of petroleum products is reported in terms of dollars per gallon. Therefore, to ensure that common units were being used, the number of barrels produced each year was divided by 42, the number of gallons in a barrel.

**Table 4-1 Baseline Petroleum Product Market Data, 2018**

| | Motor Gasoline | Jet Fuel | Distillate Fuel Oil | Residual Fuel Oil | Liquified Petroleum Gases |
|---|---|---|---|---|---|
| Price ($2010/per gallon)[1] | 3.14 | 2.57 | 3.66 | 1.83 | 2.10 |
| Quantity (billion gallons/per year)[2] | 131.53 | 22.69 | 65.15 | 5.98 | 40.62 |

[1]Source: AEO2014 Reference Case, Petroleum and Other Liquids Prices (Table 12)
[2]Source: AEO2014 Reference Case, Petroleum and Other Liquids Supply and Disposition (Table 11)

### *4.2.3 Model Parameters*

Demand elasticity is calculated as the percentage change in the quantity of a product demanded divided by the percentage change in price. An increase in price causes a decrease in the quantity demanded, hence the negative values seen in Table 4-2, which presents the demand elasticities used in this analysis. Demand is considered elastic if demand elasticity exceeds 1.0

in absolute value (i.e., the percentage change in quantity exceeds the percentage change in price). The quantity demanded, then, is very sensitive to price increases. Demand is considered inelastic if demand elasticity is less than 1.0 in absolute value (i.e., the percentage change in quantity is less than the percentage change in price). Inelastic demand implies that the quantity demanded changes very little in response to price changes. As shown in Table 4-2, we draw demand elasticities from EPA's Economic Impact Analysis for Petroleum Refineries NESHAP (EPA, 1995).

**Table 4-2 Estimates of Price Elasticity of Demand and Supply[1]**

| | Motor Gasoline | Jet Fuel | Distillate Fuel Oil | Residual Fuel Oil | Liquified Petroleum Gases |
|---|---|---|---|---|---|
| Demand elasticity | -0.69 | -0.15 | -0.75 | -0.68 | -0.80 |
| Supply elasticity | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 |

[1] The source for these elasticities is U.S. EPA (1995). The literature review performed for this EIA identified more recent estimates of long-term demand elasticities for motor gasoline, which are lower than the elasticity used in this analysis, but we were unable to identify more recent estimates of the other elasticities.

Supply elasticity is calculated as the percentage change in quantity supplied divided by the percentage change in price. An upward sloping supply curve has a positive elasticity since price and quantity move in the same direction. If the supply curve has elasticity greater than one, then supply is considered elastic, which means a small price increase will lead to a relatively large increase in quantity supplied. A supply curve with elasticity less than one is considered inelastic, which means an increase in price will cause little change in quantity supplied. In the long-run, when producers have sufficient time to completely adjust their production to a change in price, the price elasticity of supply is usually greater than one. As shown in Table 4-2, we draw supply elasticities from EPA's Economic Impact Analysis for Petroleum Refineries NESHAP (EPA, 1995).

### *4.2.4 Entering Estimated Annualized Engineering Compliance Costs into Economic Model*

To collect comprehensive, updated information for the rulemaking, EPA conducted a one-time information collection request (ICR) through a survey, under the authority of CAA section 114, of all potentially affected petroleum refineries. The ICR was comprised of four components, and the information collected through component 1 of the ICR included facility location, products produced, capacity, throughput, process and emissions, and employment and sales receipt data for 2010.[20] The throughput quantities provided were the same as those

[20] Detailed information on the ICR can be located at <https://refineryicr.rti.org/>. OMB approved the ICR on March 28, 2011. The OMB Control Number is 2060-0657, and approval expires March 31, 2014.

reported to the U.S. EIA on form EIA-810. The ICR information was used to analyze and calculate compliance costs by refinery for the rulemaking. These annualized engineering compliance costs provided the basis for the environmental cost inputs for the series of partial equilibrium economic models (EPA, 2011c).

The annualized engineering compliance cost inputs are incorporated into the partial equilibrium models on a per barrel refining capacity basis. Several steps were required to convert the annualized engineering compliance cost data, by refinery, into the data format required for the economic analysis. First, for each refinery we allocated the compliance costs across total barrels of refinery production. Because EPA collected production information for thirty-nine (39) different refinery products and the economic models allow for production input data for five product types, we then mapped the ICR product types to the shorter list of products used in the economic model (EPA, 2011c). We assumed a uniform refinery utilization rate of 86.4%, which is the operable utilization rate for U.S. refineries for 2010.[21]

[21] Recent and historical refinery utilization rate information can be located at U.S. EIA's website: <http://www.eia.gov/dnav/pet/pet_pnp_unc_dcu_nus_a.htm>.

**Table 4-3 Estimated Annualized Engineering Compliance Costs by Petroleum Product Modeled (2010 dollars)**

| | Motor Gasoline | Jet Fuel | Distillate Fuel Oil | Residual Fuel Oil | Liquified Petroleum Gases | Other | All Products |
|---|---|---|---|---|---|---|---|
| Total Annualized Engineering Compliance Costs (thousand 2010$) | $26,209 | $5,446 | $16,525 | $2,142 | $1,997 | $19,942 | $72,260 |
| Capacity (millions bbls/year) | 2,783 | 612 | 1,536 | 228 | 192 | 2,121 | 7,471 |
| Capacity (millions gallons/year) | 116,865 | 25,693 | 64,518 | 9,556 | 8,063 | 89,084 | 313,780 |
| Compliance Costs Per Gallon Capacity ($2010) | $0.00022 | $0.00021 | $0.00026 | $0.00022 | $0.00025 | $0.00022 | $0.00023 |

Using this engineering cost information and total national production of petroleum products, we estimated the annualized compliance cost per gallon of product produced. These annualized per gallon engineering compliance costs are presented in Table 4-3. For this analysis, we included engineering compliance costs that do not reflect the product recovery credits. At the national level, the total annualized engineering compliance costs are estimated at less than $0.00023 per gallon, or approximately two one-hundredths of a cent per gallon. These per-gallon annualized engineering costs estimates were then entered into the series of partial equilibrium market models to estimate impacts on the respective petroleum product markets.

### *4.2.5 Model Results*

Based on EPA's partial equilibrium analysis, the costs induced by this regulatory program do not have a significant impact on market-level prices or quantities. The results of this analysis are summarized in Table 4-4. As this table shows, prices for each of the five products rise by two one-hundredths of a penny or less per gallon, and the quantity of each petroleum product produced declines slightly. Motor gasoline and liquified petroleum gases face the largest absolute quantity reductions (4.17 million and 2.33 million gallons, respectively, or less than 0.0001 percent in both cases).

**Table 4-4 Summary of Petroleum Product Market Impacts**

| | Motor Gasoline | Jet Fuel | Distillate Fuel Oil | Residual Fuel Oil | Liquified Petroleum Gases |
|---|---|---|---|---|---|
| Change in Price (%) | < 0.0001 | 0.0001 | < 0.0001 | 0.0001 | 0.0001 |
| Change in Price (2010$) | 0.0001 | 0.0002 | 0.0002 | 0.0001 | 0.0002 |
| Change In Quantity (%) | < 0.0001 | < 0.0001 | < 0.0001 | < 0.0001 | < 0.0001 |
| Change In Quantity (million gallons per year) | -4.17 | -0.25 | -2.13 | -0.32 | -2.33 |
| | | | **Welfare Impacts** | | |
| Change in consumer surplus ($ millions) | -18.95 | -4.29 | -10.40 | -0.87 | -6.12 |
| Change in producer surplus ($ millions) | -10.32 | -0.31 | -6.03 | -0.25 | -3.70 |
| Change in total surplus ($ millions) | -29.27 | -4.60 | -16.43 | -1.12 | -9.82 |

As a result of higher prices, consumers of petroleum products see a decline in surplus, as shown in Table 4-4. For example, consumers of motor gasoline are estimated to lose $18.95 million of surplus. In addition, producers also receive a smaller surplus as a result of higher production costs. In the case of motor gasoline, producers lose $10.32 million. Total surplus losses for consumers and producers of motor gasoline are estimated to be $29.27 million. The total annualized loss in surplus for the five markets analyzed is $61.23 million. In addition to the loss in surplus for consumers and producers of these five major petroleum products, an additional $19.9 million in costs will affect markets for petroleum products that were not explicitly modeled in this analysis. These include markets for asphalt, lubricants, road oil, petroleum coke and others.

As a sensitivity analysis, we used a more recently estimated, long-run elasticity of demand for motor gasoline from Small and Van Dender (2007), which is based on cross-sectional, time-series data from the U.S. for the period of 1966-2001. If we use this elasticity (-0.38), consumers of motor gasoline could lose $22.58 million of surplus, or an additional $3.63 million loss in surplus compared to the estimate above (Small and Van Dender, 2007). In addition, producers of motor gasoline could lose $6.70 million of surplus, or reduce their surplus loss by $3.63 million.

### *4.2.6 Limitations*

Ultimately, the amendments may cause negligible increases in the costs of supplying petroleum products to consumers. The partial equilibrium model used in this EIA is designed to evaluate behavioral responses to this change in costs within an equilibrium setting within nationally competitive markets. The national competitive market assumption is clearly strong because the markets in petroleum products may be regional for some products, as well as some product markets within the refining industry may be interdependent. Regional price and quantity impacts could be different from the average impacts reported if local market structures, production costs, or demand conditions are substantially different from those used in this analysis.

## 4.3 Discussion of Employment Impacts

Executive Order 13563 directs federal agencies to consider the effect of regulations on job creation and employment. According to the Executive Order, "our regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and job creation. It must be based on the best available science" (Executive Order 13563, 2011). Although standard benefit-cost analyses have not typically included a separate analysis of regulation-induced employment impacts,[22] during the current economic recovery, employment impacts are of particular concern and questions may arise about their existence and magnitude. This section provides a conceptual framework for considering the potential influence of environmental regulation on employment in the U.S. economy and discusses the limited empirical literature that is available. The section then discusses the potential employment impacts in the environmental protection sector, e.g. for construction, manufacture, installation, and operation of needed pollution control equipment. Section 4.3.1 describes the economic theory used for analyzing regulation-induced employment impacts, discussing how standard neoclassical theory alone does not point to a definitive net effect of regulation on labor demand for regulated firms. Section 4.3.2 presents an overview of the peer-reviewed literature relevant to evaluating the effect of environmental regulation on employment. Section 4.3.3 discusses macroeconomic net employment effects. The EPA is currently in the process of seeking input from an independent expert panel on economy-wide impacts, including employment effects. Finally, Section 4.3.4 offers several conclusions.[23]

### *4.3.1 Theory*

The effects of environmental regulation on employment are difficult to disentangle from other economic changes and business decisions that affect employment, over time and across regions and industries. Labor markets respond to regulation in complex ways. That response

[22] Labor expenses do, however, contribute toward total costs in the EPA's standard benefit-cost analyses.
[23] The employment analysis in this EIA is part of EPA's ongoing effort to "conduct continuing evaluations of potential loss or shifts of employment which may result from the administration or enforcement of [the Act]" pursuant to CAA section 321(a).

depends on the elasticities of demand and supply for labor and the degree of labor market imperfections (e.g., wage stickiness, long-term unemployment, etc). The unit of measurement (e.g., number of jobs, types of jobs hours worked, or earnings) may affect observability of that response. Net employment impacts are composed of a mix of potential declines and gains in different areas of the economy (i.e., the directly regulated sector, upstream and downstream sectors, and the pollution abatement sector) and over time. In light of these difficulties, economic theory provides a constructive framework for approaching these assessments and for better understanding the inherent complexities in such assessments. In this section, we briefly describe theory relevant to the impact of regulation on labor demand at the regulated firm, in the regulated industry, and in the environmental protection sector; and highlight the importance of considering potential effects of regulation on labor supply, a topic addressed further in a subsequent section.

Neoclassical microeconomic theory describes how profit-maximizing firms adjust their use of productive inputs in response to changes in their economic conditions.[24] In this framework, labor is one of many inputs to production, along with capital, energy, and materials. In competitive output markets, profit maximizing firms take prices as given, and choose quantities of inputs and outputs to maximize profit. Factor demand at the firm, then, is determined by input and output prices.[25,26]

Berman and Bui (2001) and Morgenstern, Pizer, and Shih (2002) have specifically tailored one version of the standard neoclassical model to analyze how environmental regulations affect labor demand decisions.[27] Environmental regulation is modeled as effectively requiring certain factors of production, such as pollution abatement capital investment, that would not be freely chosen by profit maximizing/cost-minimizing firms.

In Berman and Bui's (2001, p. 274-75) theoretical model, the change in a firm's labor demand arising from a change in regulation is decomposed into two main components: output and substitution effects.[28] For the output effect, by affecting the marginal cost of production, regulation affects the profit-maximizing quantity of output. The output effect describes how, if labor-intensity of production is held constant, a decrease in output generally leads to a decrease

[24] See Layard and Walters (1978), a standard microeconomic theory textbook, for a discussion.
[25] See Hamermesh (1993), Chapter 2, for a derivation of the firm's labor demand function from cost-minimization.
[26] In this framework, labor demand is a function of quantity of output and prices (of both outputs and inputs).
[27] Berman and Bui (2001) and Morgenstern, Pizer, and Shih (2002) use a cost-minimization framework, which is a special case of profit-maximization with fixed output quantities.
[28] The authors also discuss a third component, the impact of regulation on factor prices, but conclude that this effect is unlikely to be important for large competitive factor markets, such as labor and capital. Morgenstern, Pizer and Shih (2002) use a very similar model, but they break the employment effect into three parts: 1) the demand effect; 2) the cost effect; and 3) the factor-shift effect.

in labor demand. However, as noted by Berman and Bui, although it is often assumed that regulation increases marginal cost, and thereby reduces output, it need not be the case. A regulation could induce a firm to upgrade to less polluting, and more efficient equipment that lowers marginal production costs, for example. In such a case, output could theoretically increase. For example, in the final refinery amendments, the fitting controls and monitoring equipment for storage vessels were identified as developments in practices, processes and control technologies for storage vessels. The requirement could result in fewer VOC emissions and more product remaining in the storage vessel, potentially increasing output.

The substitution effect describes how, holding output constant, regulation affects the labor-intensity of production. Although increased environmental regulation generally results in higher utilization of production factors such as pollution control equipment and energy to operate that equipment, the resulting impact on labor demand is ambiguous. For example, equipment inspection requirements, specialized waste handling, or pollution technologies that alter the production process may affect the number of workers necessary to produce a unit of output. Berman and Bui (2001) model the substitution effect as the effect of regulation on “quasi-fixed’’ pollution control equipment and expenditures that are required by the regulation and the corresponding change in labor-intensity of production. Within the production theory framework, when levels of a given set of inputs are fixed by external constraints such as regulatory requirements, rather than allowing the firm to freely choose all inputs under cost-minimization alone, these inputs are described as “quasi-fixed”. For example, materials would be a “quasi-fixed” factor if there were specific requirements for landfill liner construction, but the footprint of the landfill was flexible. Brown and Christensen (1981) develop a partial static equilibrium model of production with quasi-fixed factors, which Berman and Bui (2001) extend to analyze environmental regulations with technology-based standards.

In summary, as the output and substitution effects may be both positive, both negative or some combination, standard neoclassical theory alone does not point to a definitive net effect of regulation on labor demand at regulated firms. Operating within the bounds of standard neoclassical theory, however, rough estimation of net employment effects is possible with empirical study, specific to the regulated firms, when data and methods of sufficient detail and quality are available. The available literature illustrates some of the difficulties for empirical estimation: studies sometimes rely on confidential plant-level employment data from the U.S. Census Bureau, possibly combined with pollution abatement expenditure data that are too dated to be reliably informative. In addition, the most commonly used empirical methods in the literature do not permit the estimation of net effects. These studies will be discussed at greater length later in this chapter.

The above describes a conceptual framework for analyzing potential employment effects at a particular firm, within a regulated industry. It is important to emphasize that employment impacts at a particular firm will not necessarily represent impacts for the overall industry, therefore the theoretic approach requires some adjustment when applied at the industry level.

As stated, the responsiveness of industry labor demand depends on how the output and substitution effects interact. [29] At the industry-level, labor demand will be more responsive when: (1) the price elasticity of demand for the product is high, (2) other factors of production can be easily substituted for labor, (3) the supply of other factors is highly elastic, or (4) labor costs are a large share of the total costs of production.[30] So, for example, if all firms in the industry are faced with the same compliance costs of regulation and product demand is inelastic, then industry output may not change much at all, and output of individual firms may only be slightly changed.[31] In this case the output effect may be small, while the substitution effect will still depend on the degree of substitutability or complementarity between factors of production. Continuing the example, if new pollution control equipment requires labor to install and operate, labor is more of a complement than a substitute. In this case the substitution effect may be positive, and if the output effect is small or zero, the total effect may then be positive. As with the potential effects for an individual firm, theory alone is unable to determine the sign or magnitude of industry-level regulatory effects on labor. Determining these signs and magnitudes requires additional sector-specific empirical study. To conduct such targeted research would require estimates of product demand elasticity; production factor substitutability; supply elasticity of production factors; and the share of total costs contributed by wages, by industry, and perhaps even by facility. For environmental rules, many of these data items are not publicly available, would require significant time and resources in order to access confidential U.S. Census data for research, and also would not be necessary for other components of a typical EIA or RIA.

In addition to changes to labor demand in the regulated industry, net employment impacts encompass changes within the environmental protection sector, and, potentially in other related sectors, as well. Environmental regulations often create increased demand for pollution control equipment and services needed for compliance. This increased demand may increase revenue

[29] Marshall's laws of derived demand – see Ehrenberg & Smith, Chapter 4.
[30] See Ehrenberg & Smith, p. 108.
[31] This discussion draws from Berman and Bui (2001), p. 293.

and employment in the environmental protection industry. At the same time, the regulated industry is purchasing the equipment and these costs may impact labor demand at regulated firms. Therefore, it is important to consider the net effect of compliance actions on employment across multiple sectors or industries.

If the U.S. economy is at full employment, even a large-scale environmental regulation is unlikely to have a noticeable impact on aggregate net employment.[32] Instead, labor would primarily be reallocated from one productive use to another (e.g., from producing electricity or steel to producing pollution abatement equipment). Theory supports the argument that, in the case of full employment, the net national employment effects from environmental regulation are likely to be small and transitory (e.g., as workers move from one job to another).[33] On the other hand, if the economy is operating at less than full employment, economic theory does not clearly indicate the direction or magnitude of the net impact of environmental regulation on employment; it could cause either a short-run net increase or short-run net decrease (Schmalansee and Stavins, 2011). An important fundamental research question is how to accommodate unemployment as a structural feature in economic models. This feature may be important in evaluating the impact of large-scale regulation on employment (Smith 2012).

Affected sectors may experience transitory effects as workers change jobs. Some workers may need to retrain or relocate in anticipation of the new requirements or require time to search for new jobs, while shortages in some sectors or regions could bid up wages to attract workers. It is important to recognize that these adjustment costs can entail local labor disruptions, and although the net change in the national workforce is expected to be small, localized reductions in employment can still have negative impacts on individuals and communities just as localized increases can have positive impacts.

While the current discussion focuses on labor demand effects, environmental regulation may also affect labor supply. In particular, pollution and other environmental risks may impact labor productivity[34] or employees' ability to work. While there is an accompanying, and parallel, theoretical approach to examining impacts on labor supply, similar to labor demand, it is even more difficult and complex to study labor supply empirically. There is a small, nascent empirical

[32] Full employment is a conceptual target for the economy where everyone who wants to work and is available to do so at prevailing wages is actively employed.
[33] Arrow et. al. 1996; see discussion on bottom of p. 8. In practice, distributional impacts on individual workers can be important, as discussed in later paragraphs of this section.
[34] e.g., Graff Zivin and Neidell (2012).

literature using more detailed labor and environmental data, and quasi-experimental techniques that is starting to find traction on this question. These will be described in Section 4.3.2.3.

To summarize the discussion in this section, economic theory provides a framework for analyzing the impacts of environmental regulation on employment. The net employment effect incorporates expected employment changes (both positive and negative) in the regulated sector, the environmental protection sector, and other relevant sectors. Using economic theory, labor demand impacts for regulated firms, and also for the regulated industry, can be decomposed into output and substitution effects. With these potentially competing forces, under standard neoclassical theory estimation of net employment effects is possible with empirical study specific to the regulated firms and firms in the environmental protection sector and other relevant sectors when data and methods of sufficient detail and quality are available. Finally, economic theory suggests that labor supply effects are also possible. In the next section, we discuss the available empirical literature.

### *4.3.2 Current State of Knowledge Based on the Peer-Reviewed Literature*

In the labor economics literature there is an extensive body of peer-reviewed empirical work analyzing various aspects of labor demand, relying on the above theoretical framework.[35] This work focuses primarily on the effects of employment policies, e.g. labor taxes, minimum wage, etc.[36] In contrast, the peer-reviewed empirical literature specifically estimating employment effects of environmental regulations is very limited. In this section, we present an overview of the latter. As discussed in the preceding section on theory, determining the direction of employment effects in regulated industries is challenging because of the complexity of the output and substitution effects. Complying with a new or more stringent regulation may require additional inputs, including labor, and may alter the relative proportions of labor and capital used by regulated firms (and firms in other relevant industries) in their production processes.

Several empirical studies, including Berman and Bui (2001) and Morgenstern et al (2002), suggest that net employment impacts may be zero or slightly positive but small even in the regulated sector. Other research suggests that more highly regulated counties may generate fewer jobs than less regulated ones (Greenstone 2002, Walker 2011). However since these latter studies compare more regulated to less regulated counties they overstate the net national impact of regulation to the extent that regulation causes plants to locate in one area of the country rather than another. List et al. (2003) find some evidence that this type of geographic relocation may be

[35] Again, see Hamermesh (1993) for a detailed treatment.
[36] See Ehrenberg & Smith (2000), Chapter 4: "Employment Effects: Empirical Estimates" for a concise overview.

occurring. Overall, the peer-reviewed literature does not contain evidence that environmental regulation has a large impact on net employment (either negative or positive) in the long run across the whole economy.

Environmental regulations seem likely to affect the environmental protection sector earlier than the regulated industry. Rules are usually announced well in advance of their effective dates and then typically provide a period of time for firms to invest in technologies and process changes to meet the new requirements. When a regulation is promulgated, the initial response of firms is often to order pollution control equipment and services to enable compliance when the regulation becomes effective. This can produce a short-term increase in labor demand for specialized workers within the environmental protection sector, particularly workers involved in the design, construction, testing, installation, and operation of the new pollution control equipment required by the regulation (see Schmalansee and Stavins, 2011; Bezdek, Wendling, and Diperna, 2008). Estimates of short-term increases in demand for specialized labor within the environmental protection sector have been prepared for several EPA regulations in the past, including the Mercury and Air Toxics Standards (MATS).[37]

#### *4.3.2.1 Regulated Sector*

Determining the direction of net employment effects of regulation on industry is challenging. Two papers that present a formal theoretic model of the underlying profit-maximizing/cost-minimizing problem of the firm are Berman and Bui (2001) and Morgenstern, Pizer, and Shih (2002) mentioned above.

Berman and Bui (2001) developed an innovative approach to estimate the effect on employment of environmental regulations in California. Their model empirically examines how an increase in local air quality regulation affects manufacturing employment in the South Coast Air Quality Management District (SCAQMD), which incorporates Los Angeles and its suburbs. During the time frame of their study, 1979 to 1992, the SCAQMD enacted some of the country's most stringent air quality regulations. Using SCAQMD's local air quality regulations, Berman and Bui identify the effect of environmental regulations on net employment in the regulated industries.[38] In particular, they compare changes in employment in affected plants to those in other plants in the same 4-digit SIC industries but in regions not subject to the local regulations.[39] The authors find that "while regulations do impose large costs, they have a limited

[37] U.S. EPA (2011b)

[38] Note, like Morgenstern, Pizer, and Shih (2002), this study does not estimate the number of jobs created in the environmental protection sector.

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

effect on employment" (Berman and Bui, 2001, p. 269). Their conclusion is that local air quality regulation "probably increased labor demand slightly" but that "the employment effects of both compliance and increased stringency are fairly precisely estimated zeros, even when exit and dissuaded entry effects are included" (Berman and Bui, 2001, p. 269).[40] In their view, the limited effects likely arose because 1) the regulations applied disproportionately to capital-intensive plants with relatively little employment, 2) the plants sold to local markets where competitors were subject to the same regulations (so that sales were relatively unaffected), and 3) abatement inputs served as complements to employment.

Morgenstern, Pizer, and Shih (2002) developed a similar structural approach to Berman and Bui's, but their empirical application uses pollution abatement expenditures from 1979 to 1991 at the plant-level, including air, water, and solid waste, to estimate net employment effects in four highly regulated sectors (pulp and paper, plastics, steel, and petroleum refining). Thus, in contrast to Berman and Bui (2001), this study identifies employment effects by examining differences in abatement expenditures rather than geographical differences in stringency. They conclude that increased abatement expenditures generally have *not* caused a significant change in net employment in those sectors.

#### *4.3.2.2 Environmental Protection Sector*

The long-term effects of a regulation on the environmental protection sector, which provides goods and services that help protect the environment to the regulated sector, are difficult to assess. Employment in the industry supplying pollution control equipment or services is likely to increase with the increased demand from the regulated industry for increased pollution control.[41]

A report by the U.S. International Trade Commission (2013) shows that domestic environmental services revenues have grown by 41 percent between 2000 and 2010. According to U.S. Department of Commerce (2010) data, by 2008, there were 119,000 environmental technology (ET) firms generating approximately $300 billion in revenues domestically, producing $43.8 billion in exports, and supporting nearly 1.7 million jobs in the United States. Air pollution control accounted for 18% of the domestic ET market and 16% of exports. Small and medium-size companies represent 99% of private ET firms, producing 20% of total revenue (OEEI, 2010).

[40] Including the employment effect of existing plants and plants dissuaded from opening will increase the estimated impact of regulation on employment. This employment effect is not included in Morgenstern et. al. (2002)

[41] See Bezdek, Wendling, and Diperna (2008), for example, and U.S. Department of Commerce (2010).

*4.3.2.3 Labor Supply Impacts*

As described above, the small empirical literature on employment effects of environmental regulations focuses primarily on labor demand impacts. However, there is a nascent literature focusing on regulation-induced effects on labor supply, though this literature remains very limited due to empirical challenges. This new research uses innovative methods and new data, and indicates that there may be observable impacts of environmental regulation on labor supply, even at pollution levels below mandated regulatory thresholds. Many researchers have found that work loss days and sick days as well as mortality are reduced when air pollution is reduced.[42] EPA's study of the benefits and costs of implementing clean air regulations used these studies to predict how increased labor availability would increase the labor supply and improve productivity and the economy. [43] Another literature estimates how worker productivity improves at the work site when pollution is reduced. Graff Zivin and Neidell (2013) review the work in this literature, focusing on how health and human capital may be affected by environmental quality, particularly air pollution. In previous research, Graff Zivin and Neidell (2012) use detailed worker-level productivity data from 2009 and 2010, paired with local ozone air quality monitoring data for one large California farm growing multiple crops, with a piece-rate payment structure. Their quasi-experimental structure identifies an effect of daily variation in monitored ozone levels on productivity. They find "that ozone levels well below federal air quality standards have a significant impact on productivity: a 10 parts per billion (ppb) decrease in ozone concentrations increases worker productivity by 5.5 percent." (Graff Zivin and Neidell, 2012, p. 3654). Such studies are a compelling start to exploring this new area of research, considering the benefits of improved air quality on productivity, alongside the existing literature exploring the labor demand effects of environmental regulations.

### *4.3.3 Macroeconomic Net Employment Effects*

The preceding sections have outlined the challenges associated with estimating net employment effects within the regulated sector, in the environmental protection sector, and labor supply impacts, showing that it is very difficult to estimate the net national employment impacts of environmental regulation. Given the difficulty with estimating national impacts of regulations, EPA has not generally estimated economy-wide employment impacts of its regulations in its benefit-cost analyses. However, in its continuing effort to advance the

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[42] The Benefits and Costs of the Clean Air Act from 1990 to 2020 Final Report – Rev. A , U.S. Environmental Protection Agency, Office of Air and Radiation, April 2011a. http://www.epa.gov/air/sect812/feb11/fullreport_rev_a.pdf

[43] The Benefits and Costs of the Clean Air Act from 1990 to 2020 Final Report – Rev. A , U.S. Environmental Protection Agency, Office of Air and Radiation, April 2011a. http://www.epa.gov/air/sect812/feb11/fullreport_rev_a.pdf

evaluation of costs, benefits, and economic impacts associated with environmental regulation, EPA has formed a panel of experts as part of EPA's Science Advisory Board (SAB) to advise EPA on the technical merits and challenges of using economy-wide economic models to evaluate the impacts of its regulations, including the impact on net national employment.[44] Once EPA receives guidance from this panel it will carefully consider this input and then decide if and how to proceed on economy-wide modeling of employment impacts of its regulations.

### *4.3.4 Conclusions*

In conclusion, deriving estimates of how environmental regulations will impact net employment is a difficult task, requiring consideration of labor demand in both the regulated and environmental protection sectors. Economic theory predicts that the total effect of an environmental regulation on labor demand in regulated sectors is not necessarily positive or negative. Peer-reviewed econometric studies that use a structural approach, applicable to overall net effects in the regulated sectors, converge on the finding that such effects, whether positive or negative, have been small and have not affected employment in the national economy in a significant way. Effects on labor demand in the environmental protection sector seem likely to be positive. Finally, new evidence suggests that environmental regulation may improve labor supply and productivity.

## 4.4 Small Business Impacts 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. Under Small Business Administration (SBA) regulations, a small refiner is defined as a refinery with no more than 1,500 employees.[45] 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

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

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

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).[46]

### *4.4.1 Small Entity Economic Impact Measures*

The analysis provides EPA with an estimate of the magnitude of impacts that the final 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 the final NESHAP and NSPS amendments relies upon publically available sales and employment data from Hoovers, and where data from Hoovers was not available we used the data collected through the April 2011 Information Collection Request (EPA, 2011c). 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 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[47] 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).[48]

### *4.4.2 Small Entity Economic Impact Analysis*

As discussed in Section 2 of this EIA, as of January 2014, there were 142 petroleum refineries operating in the continental United States and US territories with a cumulative capacity

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

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

[48] 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.

of processing over 17 million barrels of crude per calendar day (EIA, 2014a). Fifty-seven (57) parent companies own these refineries, and we have employment and sales data for 52 (91%) of them. Twenty-five (25) facilities (owned by 22 parent companies) employ fewer than 1,500 workers and are considered small businesses. These firms earned an average of $1.74 billion of revenue per year, while firms employing more than 1,500 employees earned an average of $67 billion of revenue per year.[49]

Based on data collected through the April 2011 ICR, EPA performed the sales test analysis for impacts on affected small refineries (EPA, 2011c). Five (5) of the 25 small refiners were removed from the analysis because we determined they were not major sources and would not be subject to the rules, and two (2) of the 25 small refiners were not analyzed because we had no ICR and/or other publically available employment and sales data. The 5 small refiners removed from the analysis had parent company revenues ranging from $5 million to $225 million, with average revenues of $64 million. Two of these small refiners had revenues of less than $10 million, and another small refiner had revenues just over $10 million. Of the 2 small refiners that were not analyzed because of missing data, one (1) small refiner shut down in 2007 and the other provided information that they were a specialty chemical company and not a refinery. These seven small refiners will not be subject to the rule.

Table 4-5 presents the distribution of estimated cost-to-sales ratios for the small firms in our analysis. We analyzed the estimated cost-to-sales with and without the recovery credit, and in both cases 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 4-5 Impact Levels of NESHAP and 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% | 18 | 100% |
| Cost-to-Sales Ratio 1-3% | 0 | -- |
| Cost-to-Sales Ratio greater than 3% | 0 | -- |

[49] 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.

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 4-6, for large firms, without recovery credits the average cost-to-sales ratio is approximately 0.01 percent; the median cost-to-sales ratio is less than 0.01 percent; and the maximum cost-to-sales ratio is approximately 0.64 percent; with recovery credits these impacts do not substantially change, except the maximum cost-to-sales ratio decreases to approximately 0.44 percent. For small firms, without recovery credits the average cost-to-sales ratio is about 0.16 percent, the median cost-to-sales ratio is 0.04 percent, and the maximum cost-to-sales ratio is 0.80 percent; with recovery credits these impacts do not substantially change, except the maximum cost-to-sales ratio decreases slightly to approximately 0.78 percent. The potential costs do not have a more significant impact on small refiners and because no small firms are expected to have cost-to-sales ratios greater than one percent, we determined that the cost impacts for the risk and technology reviews for existing MACT 1 and MACT 2 standards will not have a significant economic impact on a substantial number of small entities (SISNOSE).

**Table 4-6 Summary of Sales Test Ratios for Firms Affected by NESHAP and 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 | 18 | 33% | 0.16% | 0.04% | <0.01% | 0.80% |
| Large | 37 | 67% | 0.01% | <0.01% | <0.01% | 0.64% |
| All | 55 | 100% | 0.03% | <0.01% | <0.01% | 0.80% |

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