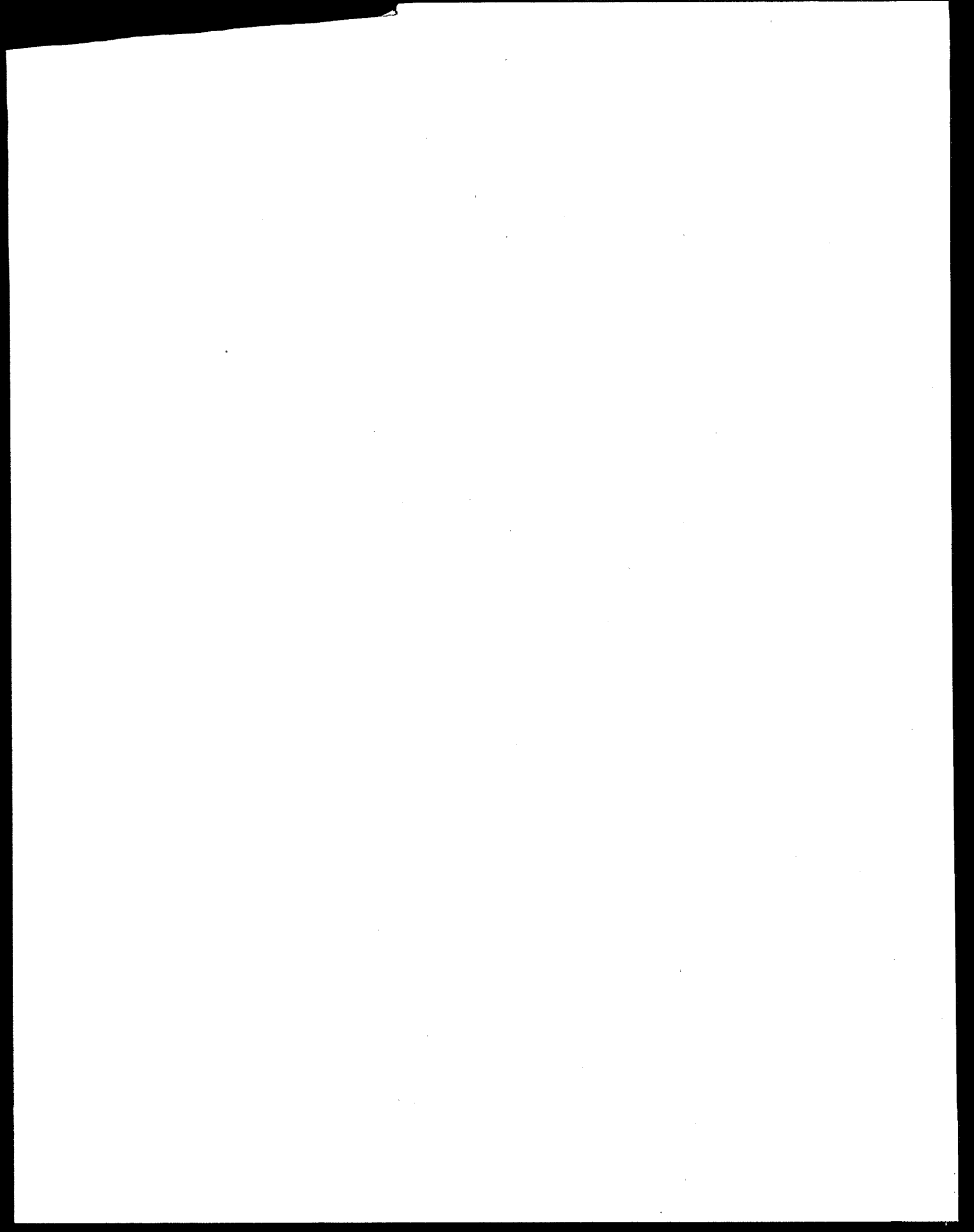


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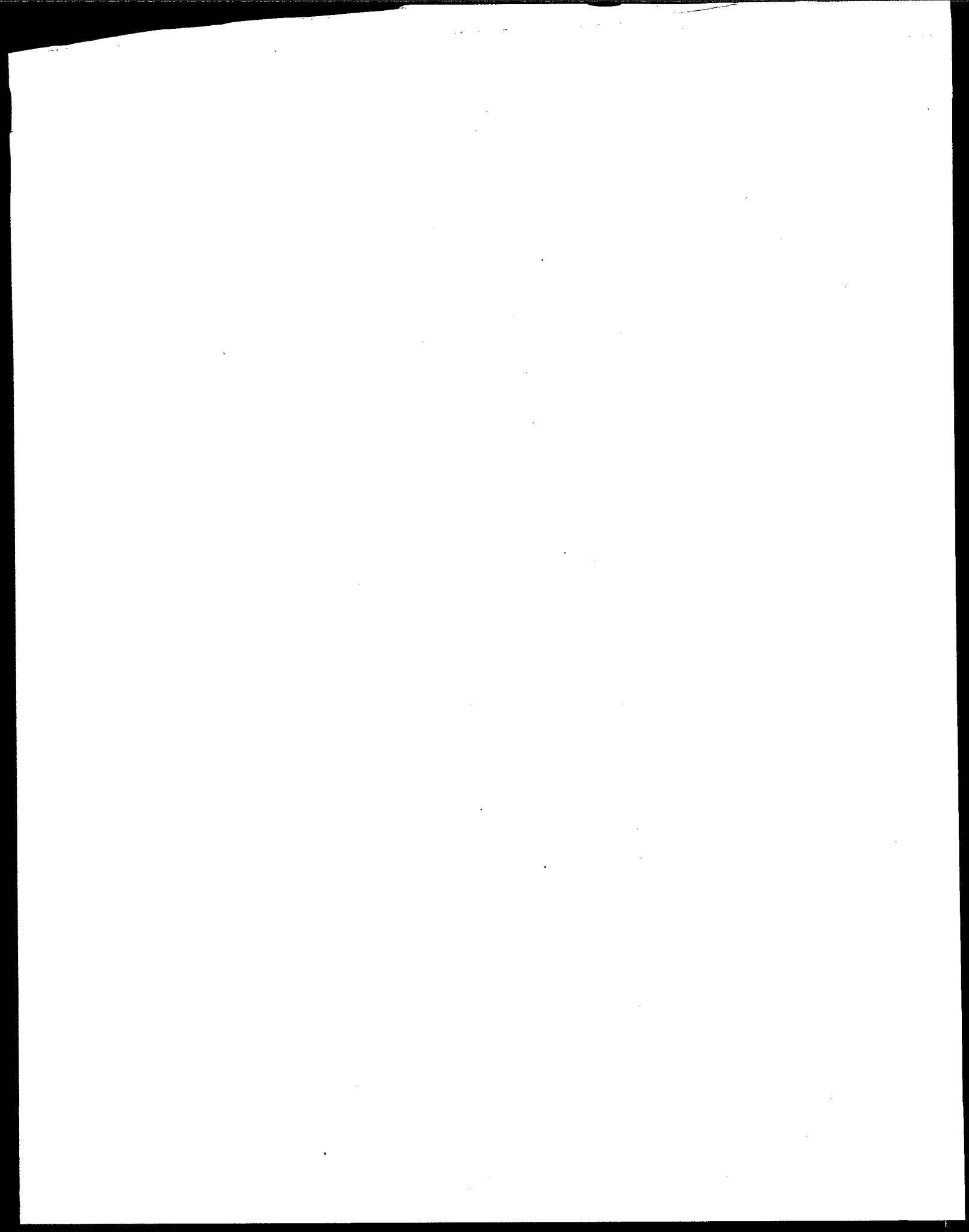
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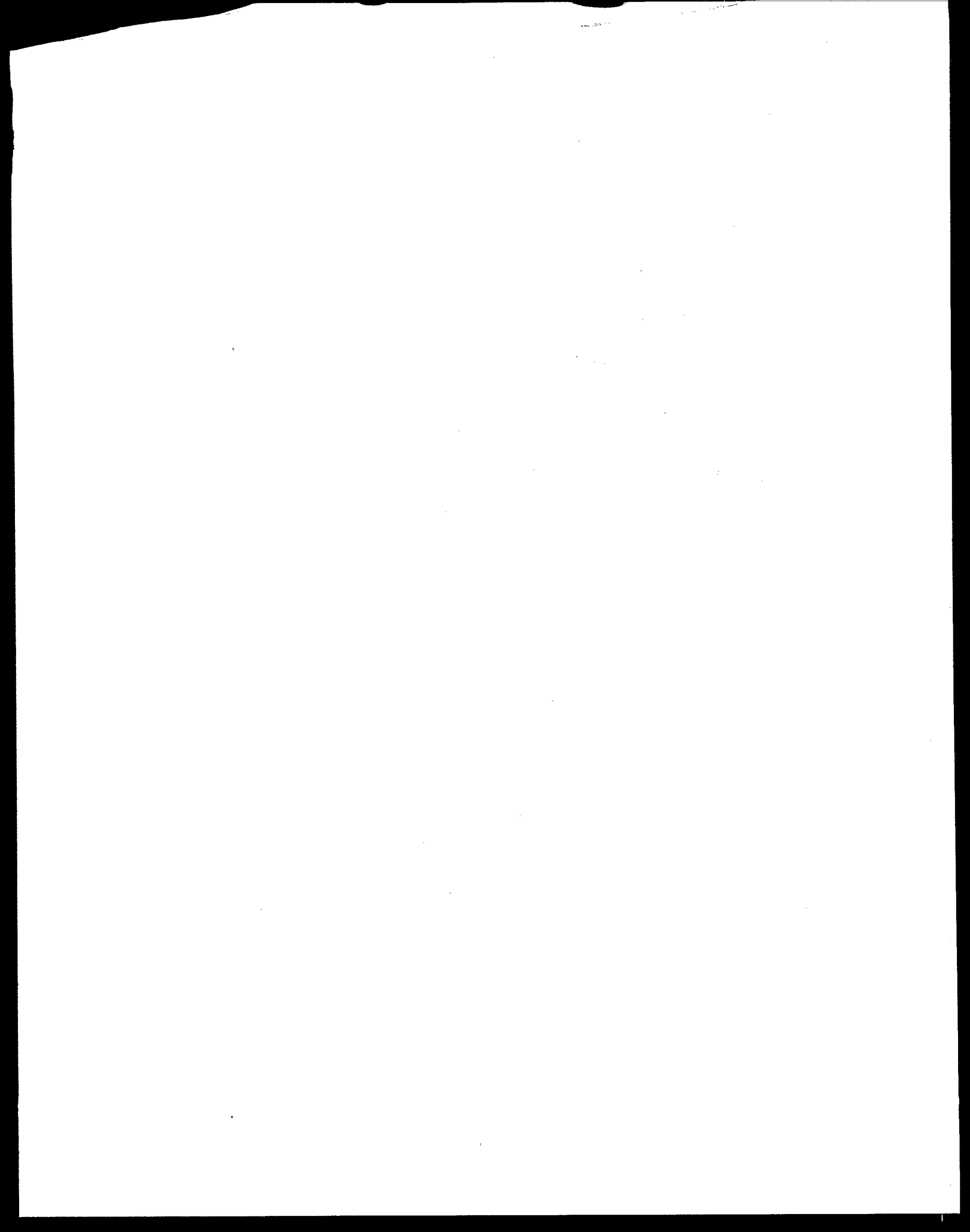
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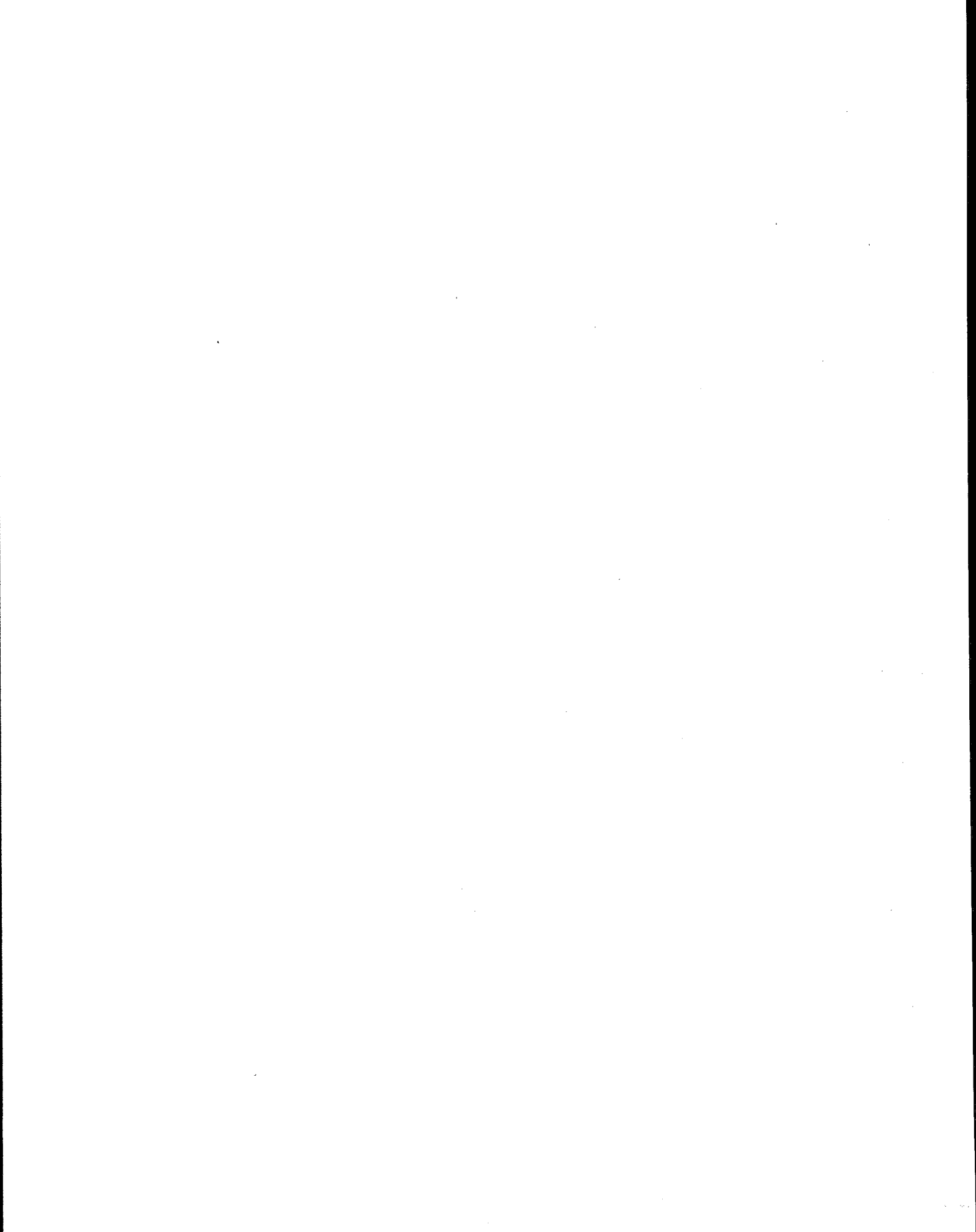
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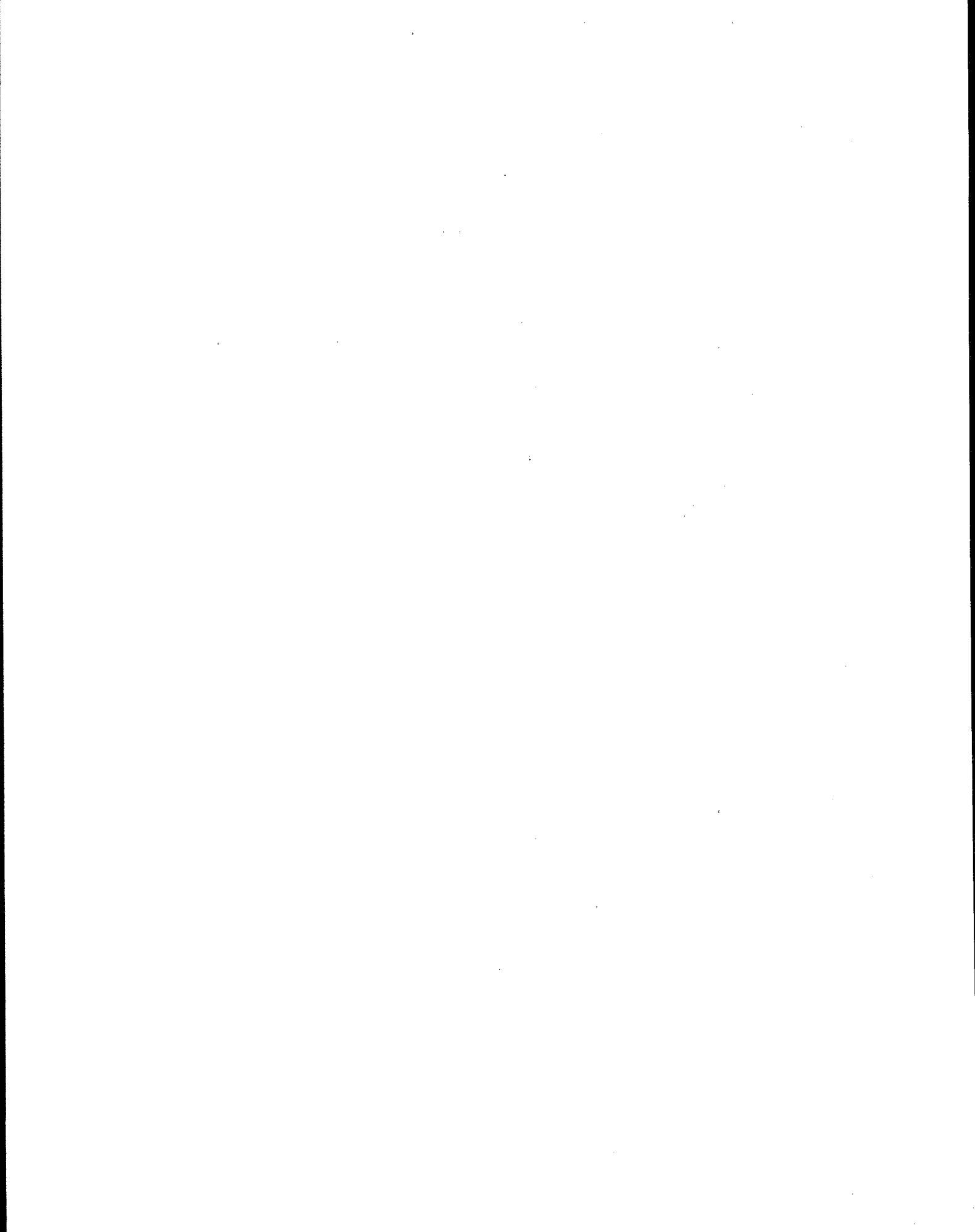
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## ACRONYMS AND ABBREVIATIONS

API	American Petroleum Institute
ASM	Annual Survey of Manufactures
bbl	One barrel; equal to 42 gallons
bbl/d	barrels per day
BCA	Benefit Cost Analysis
BWON	Benzene Waste Operations NESHAP (NESHAP is defined below)
CAA	Clean Air Act Amendments of 1990
C/E	cost effectiveness
CERA	Cambridge Energy Research Associates
DOC	Department of Commerce
DOE/EIA	Department of Energy/Energy Information Administration
EIA	economic impact analysis
EPA	Environmental Protection Agency
FCCU	fluidized catalytic cracking unit
HAP	Hazardous Air Pollutant
HEM	Human Exposure Model
HON	Hazardous Organic NESHAP (NESHAP is defined below)
IARC	International Agency for Research on Cancer
kPa	kilopascal
LDAR	leak detection and repair
LEL	lower explosive limit
LPGs	Liquefied Petroleum Gases
lpm	liter per minute
MACT	Maximum Achievable Control Technology
MIR	maximum individual risk
MRR	monitoring, recordkeeping, and reporting
MTBE	Methyl tertiary butyl ether
Mg	Megagram
NAAQS	National Ambient Air Quality Standard
NESHAP	National Emission Standard for Hazardous Air
Pollutants	
NSPS	New Source Performance Standard
NO <sub>x</sub>	nitrogen oxide
OGJ	Oil and Gas Journal
OMB	Office of Management and Budget
PADD	Petroleum Administration for Defense Districts
ppmv	parts per million by volume
RACT	Reasonably Available Control Technology
RFA	Regulatory Flexibility Act; also Regulatory Flexibility Analysis
RfC	reference-dose concentration
RIA	Regulatory Impact Analysis
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SO <sub>2</sub>	sulfur dioxide
SOCMI	Synthetic Organic Chemical Manufacturing industry
URF	unit risk factor
VOC	volatile organic compound



## EXECUTIVE SUMMARY

### ES.1 PURPOSE AND STATUTORY AUTHORITY

This report analyzes the regulatory impacts of the Petroleum Refinery National Emission Standard for Hazardous Air Pollutants (NESHAP), which is being promulgated under Section 112 of the Clean Air Act Amendments of 1990 (CAA). This emission standard would regulate the emissions of certain hazardous air pollutants (HAPs) from petroleum refineries. The petroleum refineries industry group includes any facility engaged in the production of motor gasoline, naphthas, kerosene, jet fuels, distillate fuel oils, residual fuel oils, lubricants, or other products made from crude oil or unfinished petroleum derivatives. This report analyzes the impact that regulatory action is likely to have on the petroleum refining industry, and on society as a whole.

The President issued Executive Order 12866 on October 4, 1993, which requires EPA to prepare RIAs (or economic assessments) for all "significant" regulatory actions. At proposal, EPA determined that the petroleum refinery NESHAP is a "significant" rule because it had an estimated annual cost on the economy of more than \$100 million, and is therefore subject to the requirements of Executive Order 12866. As shown later in the report, that cost is now less than \$100 million, but it has been decided that due to the level of interest in the results of the analyses that make up this report that revising the RIA for promulgation was necessary. This report satisfies the requirements of the executive order. In addition to a mandatory assessment of benefits and costs, E.O. 12866 specifies that EPA, to the extent allowed by the CAA and court orders, demonstrate

(1) that the benefits of the NESHAP regulation will outweigh the costs and (2) that the maximum level of net benefits (including potential economic, environmental, public health and safety and other advantages; distributive impacts; and equity) will be reached. EPA has chosen to focus on one regulatory option, the chosen regulatory alternative (referred to as "Alternative 1") and calculated the compliance costs, economic impacts, and benefits from implementing that alternative to the greatest extent possible.

The petroleum refinery NESHAP would require sources to achieve emission limits reflecting the application of the maximum achievable control technology (MACT), consistent with sections 112(d) and 112(h) of the CAA. Section 112 of the CAA provides a list of 189 HAPs and directs the EPA to develop rules to control HAP emissions. For the Petroleum Refinery NESHAP, EPA chose regulatory options based on control options on an emission point basis. An emission point is defined as a point within a refinery which emits one or more HAPs. The emission points to be regulated under the source category for this standard are: equipment leaks, storage vessels, miscellaneous process vents, and wastewater collection and treatment systems.

## **ES.2 PROMULGATED PETROLEUM REFINERY EMISSION STANDARD**

The promulgated rule, the Petroleum Refinery NESHAP, would require sources to achieve emission limits reflecting the application of MACT. The definition of source in the proposed standard is "the collection of emission points in HAP-emitting petroleum refining processes within the source category." The source comprises all miscellaneous process vents, storage vessels, wastewater collection and treatment systems, and equipment leaks associated with petroleum refining process units that are located at a single plant site covering a contiguous area under common control. The definition of source is an important element of this NESHAP because it describes the specific grouping of emission points within the source category

to which each standard applies. The rule is made up of seven different subjects: applicability, definitions, and general standards; miscellaneous process vent provisions; storage vessel provisions; wastewater provisions; equipment leak provisions; recordkeeping and reporting provisions; and emissions averaging. The promulgated rule outlines the chosen option for controlling HAP emissions from each of the four emission points within a refinery source, given existing control technology.

The *applicability* of the rule refers to the definition of the source within the petroleum refinery source category. The emission standard applies to petroleum refining process units that are part of a major source as defined in Section 112 of the CAA. EPA's initial source category list (57 FR 31576, July 16, 1992), required by section 112(c) of the Act, identifies categories of sources for which NESHAP are to be established. Two categories of sources are listed in the initial source category list for petroleum refineries: (1) catalytic cracking (fluid and other) units, catalytic reforming units, and sulfur plant units and (2) other sources not distinctly listed. Based on an EPA review of information on petroleum refineries during development of the proposed standards, it was determined that some of the emissions points from the two listed categories of sources have similar characteristics and can be controlled by the same control techniques. EPA determined that it is most effective to regulate these emission points in a single regulation.

EPA intends to amend the source category list to define the processes and emission points regulated in this rule as one source category. Catalyst regeneration vents, catalytic cracking units, catalytic reforming units, and vents from sulfur recovery plants are being defined as the second source category.

Data analyses conducted in developing the MACT floor for *miscellaneous process vents* determined that controls can achieve 98 percent organic HAP reduction or an outlet organic HAP concentration of 20 ppmv or less for all vent streams. The *storage vessel* provision specifies the control systems which represent the MACT floor to be applied to storage vessels. The

wastewater provisions of this rule are based on the benzene waste operations NESHAP (BWON), which controls 75 percent of the benzene in refinery wastewater. The wastewater streams subject to this rule include water, raw material, intermediate product, by-product, co-product, or waste material that contains HAPs and is discharged into an individual drain system. The equipment leak provisions of the promulgated rule are based on the Petroleum Refinery NSPS Equipment Leak provisions, as well as the negotiated equipment leak regulation included in the Hazardous Organics NESHAP (HON) (40 CFR 63 subpart H).

The rule specifies the necessary recordkeeping and reporting requirements to verify compliance with the MACT floor for each of the four emission points. EPA is also allowing emission averaging among existing miscellaneous process vents, storage tanks, and wastewater streams within a refinery. Under emission averaging, a system of emission "credits" and "debits" would be used to determine whether the source is achieving the required emission reductions. With emissions averaging as part of the standard, the rule contains specific equations and procedures for calculating credits and debits.

### ES.3 NEED FOR REGULATION

One of the concerns about potential threats to human health and the environment from petroleum refineries is the emission of HAPs. Health risks from emissions of HAPs into the air include increases in cancer incidences, genotoxicity, neurotoxicity, liver damage, cardiovascular impairment, and other toxic effects. In addition to threats to human health, there are also detrimental effects on human welfare, such as reduced agricultural crop yields and reduced ecosystem diversity and activity. The U.S. Office of Management and Budget (OMB) directs regulatory agencies to demonstrate the need for an economically significant rule. The RIA must show that a market failure exists and that it cannot be resolved by measures other than Federal regulation. Externality is one type of market failure. HAP emissions represent an externality in that refinery operation imposes costs on others outside of the marketplace. In the case of this type



of negative externality, the market price of goods and services does not reflect the costs borne by receptors of the HAPs generated in the refining process. With the NESHAP in effect, the amount that refiners must incur to refine petroleum products will more closely approximate the full social costs of production. The necessity for a uniform national standard is based on the determination that air pollution crosses jurisdictional lines, and uniform national standards, unlike potentially piecemeal local standards, will be more efficient to both industry and government.

#### ES.4 CONTROL TECHNIQUES AND REGULATORY ALTERNATIVES

The promulgated regulation requires a broad range of control techniques as options for compliance with the standard. Combustion technology, internal floating roofs, and product recovery devices, including internal floating roofs and vapor recovery tanks, are all part of the technology requirements for the Petroleum Refinery NESHAP. In addition, leak detection and repair (LDAR) programs will be used to control equipment leaks.

Based on the determination of the MACT floor for each of the four emission points, EPA developed a single regulatory alternative, Alternative 1. It is a hybrid option, that incorporates MACT floor level control for wastewater collection and treatment systems, storage vessels, and miscellaneous process vents, and an option above the floor for equipment leaks. Cost and emission data were unavailable to compare this alternative with a second alternative to examine the incremental costs and benefits of going to another alternative.

#### ES.5 COST ANALYSIS

The annualized compliance costs by emission point are shown in Table ES-1 for the chosen alternative. The total national cost of Alternative 1 in the fifth year is \$79 million.

TABLE ES-1. SUMMARY OF TOTAL COSTS IN THE FIFTH YEAR  
FOR THE PETROLEUM REFINERIES NESHAP

		Capital Costs and Annual Fifth Year Costs (1000\$/yr) (1992 Dollars)				Alternative 1
Emission Point	Option	Total Capital Costs	Existing Sources	New Construction	Total	
Equipment Leaks	Floor Option 1 <sup>1</sup>	\$142,000	\$69,000 \$58,000	\$ 0 \$(210)	\$69,000 \$57,790	\$57,790
Miscellaneous Process Vents	Floor Floor <sup>1</sup>	\$21,000	\$12,000	\$370	\$12,370	\$12,370
Wastewater Systems	Floor <sup>1</sup>	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0
Storage Vessels	Floor <sup>1</sup>	\$48,000	\$8,000	\$98	\$8,098	\$8,098
Other Recordkeeping and Reporting		\$2,000				\$1,000
<b>TOTAL COST</b>		<b>\$213,000</b>				<b>\$79,190</b>

NOTES: <sup>1</sup>Alternative 1.

In addition to provisions for the installation of control equipment, the promulgated regulation includes requirements for monitoring, recordkeeping, and reporting (MRR). EPA estimates that the total annual cost for refineries to comply with the MRR requirements is \$20 million, an amount included in the compliance cost estimate of \$79 million. The MRR requirements are outlined separately in the promulgated regulation for each emission point.

#### ES.6 ECONOMIC IMPACTS AND SOCIAL COSTS

An economic impact analysis (EIA) was conducted to evaluate the effect of increased compliance costs for emission control equipment on the domestic petroleum refining market. The partial equilibrium model used in the EIA utilized the costs for Alternative 1 which were presented in Table ES-1 to estimate primary market impacts including increases in price of refined petroleum products, decreases in output levels, changes in the value of domestic shipments, and possible refinery closures. Estimated secondary effects include labor market adjustments, energy input market changes, and foreign trade effects. Welfare changes for consumers, producers, and society at large or the social costs of the emission controls were also evaluated. The estimated market changes from the use of these emission controls were relatively small.

The social costs of regulation incorporate costs borne by society for pollution abatement. The social costs reflect the opportunity cost or economic cost of resources used in emission control. Consumers, producers, and all of society bear the costs of pollution controls in the form of higher prices, lower quantities produced, and possible tax revenues that may be gained or lost. The annual social cost estimates for Alternative 1 is shown in Table ES-2. The social costs are used later in the RIA to conduct a benefit cost analysis, for the proper costs to compare benefits with are the social costs, since the benefits are to society as a whole. As seen in Table ES-2, the social costs are \$95 million annually, \$16 million higher than the compliance costs alone.

TABLE ES-2. ANNUAL SOCIAL COST ESTIMATES FOR THE PETROLEUM REFINERIES NESHAP

Social Cost Category	Net Costs <sup>1</sup> (millions of 1992 dollars)
Surplus Losses for Preferred Alternative:	
Change in Consumer Surplus	\$342.86
Change in Producer Surplus	\$(174.32)
Change in Residual Surplus to Society <sup>2</sup>	\$(73.25)
Total Social Cost of Alternative 1 <sup>3</sup>	\$95.29

- NOTES: <sup>1</sup>Brackets indicate negative surplus losses or surplus gains.  
<sup>2</sup>Residual surplus loss to society includes adjustments necessary to equate the relevant discount rate to the social cost of capital and to consider appropriate tax effect adjustments.  
<sup>3</sup>Alternative 1 includes floor controls for all emission points except equipment leaks. Option 1 is preferred to the floor for equipment leaks because it is a less costly option than the floor. The social costs was calculated by reducing the social costs for the chosen alternative (Alternative 1) at proposal minus the reduction in annual engineering cost estimates between proposal and promulgation, and assuming the same percentage change in the social costs.

## ES.7 QUALITATIVE ASSESSMENT OF BENEFITS OF EMISSION REDUCTIONS

This RIA presents the results of an examination of the health and welfare benefits associated with air emission reductions projected as a result of implementation of the petroleum refinery NESHAP. The promulgated regulation is expected to reduce emissions of HAPs emitted from storage tanks, process vents, equipment leaks, and wastewater emission points at refining sites. Of the HAPs emitted by petroleum refineries, some are classified as VOCs, which are ozone precursors. HAP benefits are presented separately from the benefits associated specifically with VOC emission reductions.

The predicted emissions of a few HAPs associated with this regulation have been classified as **probable or known human carcinogens**. As a result, one of the benefits of the proposed regulation is a reduction in the risk of cancer mortality. Other benefit categories include reduced exposure to noncarcinogenic HAPs, and reduced exposure to VOCs.

Emissions of VOCs have been associated with a variety of health and welfare impacts. VOC emissions, together with  $\text{NO}_x$ , are precursors to the formation of tropospheric ozone. Exposure to ambient ozone is most directly responsible for a series of respiratory related adverse impacts.

## ES.8 QUANTITATIVE ASSESSMENT OF BENEFITS

Benefits were quantified from VOC emission reduction for two categories, reduced acute health effects in ozone nonattainment areas and increased agricultural crop yields nationwide. The quantification of dollar benefits for all benefit categories is not possible at this time because of limitations in both data and available methodologies, but the monetized benefits quantified exceed the costs of the rule. Since the dollar benefits could not be quantified for all benefit categories (including acute health effects in ozone attainment areas and chronic health effects nationwide), the resulting monetized benefits estimate is an underestimate.

Although an estimate of the total reduction in HAP emissions for various control options has been developed for this RIA, it has not been possible to identify the speciation of the HAP emission reductions for each type of emission point. However, an estimate of HAP speciation for equipment leaks has been made. Using emissions data for equipment leaks and the Human Exposure Model (HEM), the annual cancer risk caused by HAP emissions from petroleum refineries was estimated. Generally, this benefit category is calculated as the difference in estimated annual cancer incidence before and after implementation of each regulatory alternative. The annual cancer incidence associated with this rule was less than one statistical life per year. EPA's risk assessment indicates that over 4.5 million people exposed to refinery emissions have an individual risk greater than 1 in 1 million from exposure to benzene, a known human carcinogen.

The benefits of reduced emissions of VOC from a MACT regulation of petroleum refineries were quantified using the technique of "benefits transfer." Because there is an assumption incorporated into a report completed by the Office of Technology Assessment (OTA) from which benefits transfer values were obtained that no health benefits are experienced in attainment areas, an assumption that is conservative, the VOC emission reductions used in this analysis for computing health benefits are defined in terms of reductions occurring only in non-attainment areas. (Nonattainment areas are geographical locations in which the Federal ambient air quality standard (NAAQS) for ozone has been violated.) Table ES-3 presents the VOC emission reductions for refineries in nonattainment and attainment areas associated Alternative 1, the chosen alternative.

The benefit transfer ratio range for acute health impacts used in this analysis is presented in Table ES-4. In order to quantify VOC emission reductions for these impacts, the ratios were multiplied by VOC emission reductions from petroleum refineries located in ozone non-attainment areas. Estimated health benefits from VOC emission reductions were \$108.5 million,

the midpoint of a range from \$3.4 - \$213.5 million. Benefits from increase in agricultural yields from decreased ozone concentrations due to VOC emission reductions, calculated for attainment and nonattainment areas, were estimated at \$44.9 million, the midpoint of a range from \$30.3 - \$59.5 million. The resulting total annual benefits were \$153.4 million, again a midpoint, this time of a range from \$33.7 - \$273.0 million.

TABLE ES-3. VOC EMISSION REDUCTIONS BY EMISSION POINT

Emission Point <sup>2</sup>	VOC Emission Reductions by Regulatory Alternative (Mg/yr) <sup>3</sup>	
	Alternative 1	
	Nonattainment <sup>1</sup>	Attainment
Equipment Leaks	56,601	69,052
Miscellaneous Process Vents	76,426	47,438
Storage Vessels	2,256	1,227
TOTAL REDUCTION BY ATTAINMENT STATUS	134,283	117,717
TOTAL REDUCTION FOR ALTERNATIVE	252,000	

<sup>1</sup>VOC emission reductions include only those associated with control of the 87 refineries located in ozone nonattainment areas.

<sup>2</sup>No further control is assumed for wastewater streams, and therefore, emission reductions associated with this emission point is zero.

<sup>3</sup>Emission reduction estimates do not incorporate reductions occurring at new sources.

TABLE ES-4. BENEFIT PER MEGAGRAM VALUES FOR VOC REDUCTIONS

Benefits Transfer Value <sup>1</sup>	1992 Dollars/Megagram <sup>2</sup>
Average	\$800
Range	\$25 - \$1,574

<sup>1</sup>The benefits transfer value in the table quantifies only the benefits attributable to reduced acute health impacts in ozone nonattainment areas.

<sup>2</sup>Values are in first quarter 1992 dollars.

#### ES.9 COMPARISON OF BENEFITS TO COSTS

Table ES-5 depicts a comparison of the benefits of implementing the chosen regulatory alternative only to the compliance and social costs. Data for calculating the benefits for a second alternative were not available, thus the Agency was unable to examine the incremental benefits and incremental costs of going to a second alternative and determine if maximum net benefits are approached with the chosen alternative. There are positive net benefits from control at the chosen alternative, however. The net benefits to society are \$58.1 million annually from compliance with the standard.



TABLE ES-5. COMPARISON OF ANNUAL BENEFITS TO COSTS FOR THE  
PETROLEUM REFINERIES NESHAP  
(MILLIONS OF 1992 DOLLARS PER YEAR)

	Alternative 1
Benefits	\$153.40
Social Costs	\$(95.29)
Benefits Less Social Costs	\$58.11

( ) represent costs or negative values.



## 1.0 INTRODUCTION

The regulation under analysis in this report, which is being promulgated under Section 112 of the Clean Air Act Amendments of 1990 (CAA), is the Petroleum Refinery National Emission Standard for Hazardous Air Pollutants (NESHAP). This emission standard would regulate the emissions of certain hazardous air pollutants (HAPs) from petroleum refineries. The petroleum refineries industry group includes any facility engaged in producing motor gasoline, naphthas, kerosene, jet fuels, distillate fuel oils, residual fuel oils, lubricants, or other products made from crude oil or unfinished petroleum derivatives. This report analyzes the impact that regulatory action is likely to have on the petroleum refining industry, and on society as a whole. Included in this chapter is a summary of the purpose of this regulatory impact analysis (RIA), the statutory history which preceded this regulation, and a description of the content of this report.

### 1.1 PURPOSE

The President issued Executive Order 12866 on October 4, 1993. It requires EPA to prepare RIAs for all "significant" regulatory actions. The criteria set forth in Section 1 of the Order for determining whether a regulation is a significant rule are that the rule: (1) is likely to have an annual effect on the economy of \$100 million or more, or adversely and materially affect a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities; (2) is likely to create a serious inconsistency or otherwise interfere with an action taken or planned by another agency; (3) is likely to materially alter the budgetary impact of entitlements, grants, user fees, or loan

programs or the rights and obligation of recipients thereof; or (4) is likely to raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order. At proposal, EPA determined that the petroleum refinery NESHAP is a "significant" rule because it will have an annual effect on the economy of more than \$100 million, and is therefore subject to the requirements of Executive Order 12866. While the NESHAP is no longer a "significant" rule due to the annual effect on the economy now estimated to be less than \$100 million, the RIA has been revised and a final version will be available at promulgation.

Along with requiring an assessment of benefits and costs, E.O. 12866 specifies that EPA, to the extent allowed by the CAA and court orders, demonstrate (1) that the benefits of the NESHAP regulation will outweigh the costs and (2) that the maximum level of net benefits (including potential economic, environmental, public health and safety and other advantages; distributive impacts; and equity) will be reached. EPA has chosen a single regulatory option for evaluation in this RIA. Benefits and costs are quantified to the greatest extent allowed by available data. As stipulated in E.O. 12866, in deciding whether and how to regulate, EPA is required to assess all costs and benefits of available regulatory alternatives, including the alternative of not regulating. Accordingly, the cost benefit analysis in this report is measured against the baseline, which represents industry and societal conditions in the absence of regulation.

## 1.2 LEGAL HISTORY AND STATUTORY AUTHORITY

The petroleum refinery NESHAP would require sources to achieve emission limits reflecting the application of the maximum achievable control technology (MACT), consistent with sections 112(d) and 112(h) of the CAA. This section provides a brief history of Section 112 of the Act and background regarding the definition of source categories and emission points for Section 112 standards.

Section 112 of the Act provides a list of 189 HAPs and directs the EPA to develop rules to control HAP emissions. The CAA

requires that the rules be established for categories of sources of the emissions, rather than being set by pollutant. In addition, the CAA establishes specific criteria for establishing a minimum level of control and criteria to be considered in evaluating control options more stringent than the minimum control level. Assessment and control of any remaining unacceptable health or environmental risk is to occur 8 years after the rules are promulgated.

For the subject NESHAP, EPA chose regulatory options based on control options on an emission point basis. The petroleum refinery NESHAP regulates emissions of all HAPs emitted from all emission points at both new and existing petroleum refinery sources. An emission point is defined as a point within a refinery which emits one or more HAPs. The emission points to be regulated under the source category for this standard are: equipment leaks, storage vessels, miscellaneous process vents, and wastewater collection and treatment systems.

### 1.3 REPORT ORGANIZATION

Chapter 2 presents a summary of the promulgated regulation for the Petroleum Refinery NESHAP. Executive Order 12866 requires EPA to prove that regulation is necessary due to a compelling public need, such as material failures of private markets to protect or improve the health and safety of the public, the environment, or the well-being of the public. In order to satisfy this requirement, Chapter 3 presents the market conditions which necessitate regulatory action. A characterization of the air emissions associated with the petroleum refining process, and the significance of the environmental problem which EPA intends to address through regulation are assessed. An explanation of how the regulation is consistent with the CAA is also presented.

Chapter 4 identifies the control techniques and regulatory alternatives which were considered for the standard. EPA's designation of control options reflects the best control technology available to refineries, given existing technology levels. Chapter 5 presents the approach for estimating

regulatory compliance costs, the quantitative estimates of each control option under analysis, and the issues and assumptions upon which the estimates were based. The associated emission reductions and cost effectiveness of the regulatory options are also presented.

Chapter 6 provides an economic profile of the petroleum refining industry, and describes the methodology used to estimate the economic effects of a chosen hybrid option on the industry. Predicted price, output, employment, and closure impacts are presented as well as a quantification of the social costs of the regulatory option.

Chapter 7 provides a qualitative description of the benefits associated with the regulatory action. As explained in this chapter, some benefits are nonquantifiable and therefore cannot be usefully estimated. Qualitative measures of the air related benefits associated with a decrease in HAP emissions are presented separately from those associated with a decrease in volatile organic compound (VOC) emissions. Benefits which are difficult to quantify, but nevertheless essential to consider, are also identified in this chapter.

Chapter 8 provides a quantitative assessment of those benefits which were identified in Chapter 7. The methodology used to arrive at these estimates is outlined and any limitations are identified. The quantitative estimates of benefits associated with risk reductions and human health effects are presented separately.

The Executive Order requires EPA to assess both the costs and the benefits of the intended regulation and, recognizing that some costs and benefits are difficult to quantify, adopt a regulation only on a determination that the benefits of the regulation justify the costs. Chapter 9 compares the annualized costs to the annualized benefits for each of the two regulatory options in this RIA. Economic efficiency is considered within the context of a welfare analysis, using the social costs of regulation.

## 2.0 PROMULGATED PETROLEUM REFINERIES EMISSION STANDARD IN BRIEF

The discussion in this chapter briefly summarizes the requirements of the rule, without accounting for how the provisions were selected or how emission cutoffs were determined. The promulgated rule, the NESHAP for petroleum refineries, would require sources to achieve emission limits reflecting the application of MACT, consistent with sections 112(d) and 112(h) of the CAA. The promulgated rule would regulate the emissions of the organic HAPs identified on the list of 189 HAPs in the CAA at both new and existing petroleum refinery sources.

The final standard defines *source* as the collection of emission points in HAP-emitting petroleum refining processes within the source category. The source comprises all miscellaneous process vents, storage vessels, wastewater streams, and equipment leaks associated with petroleum refining process units that are located at a single plant site covering a contiguous area under common control. The definition of source is an important element of this NESHAP because it describes the specific grouping of emission points within the source category to which each standard applies.

### 2.1 THE EMISSION STANDARD IN BRIEF

The rule is made up of seven different subjects: applicability, definitions, and general standards; miscellaneous process vent provisions; storage vessel provisions; wastewater provisions; equipment leak provisions; recordkeeping and reporting provisions; and emissions averaging. Each of these sections is summarized below.

### 2.1.1 *Applicability of the Petroleum Refinery NESHAP*

The *applicability* of the rule refers to the definition of the source within the petroleum refinery source category. Petroleum refineries are defined as facilities engaged in producing motor gasoline, naphthas, kerosene, jet fuels, distillate fuel oils, residual fuel oils, or other transportation fuels, heating fuels, or lubricants from crude oil or unfinished petroleum derivatives. The emission standard applies to petroleum refining process units that are part of a major source as defined in Section 112 of the CAA. EPA's initial source category list (57 FR 31576, July 16, 1992), required by section 112(c) of the Act, identifies categories of sources for which NESHAP are to be established. This list includes all categories of major sources of HAPs known to the EPA at this time, and all area source categories for which findings of adverse effects warranting regulation have been made. Two categories of sources are listed in the initial source category list for petroleum refineries: (1) catalytic cracking (fluid and other) units, catalytic reforming units, and sulfur plant units and (2) other sources not distinctly listed.

Based on an EPA review of information on petroleum refineries during development of the promulgated standards, it was determined that some of the emissions points from the two listed categories of sources have similar characteristics and can be controlled by the same control techniques. In particular, miscellaneous process vents emitting organic HAPs, storage vessels, wastewater streams, and leaks from equipment in organic HAP service within catalytic cracking units, catalytic reforming units, and sulfur plant units are similar to emission points from the other process units at petroleum refineries. EPA determined that it is most effective to regulate these emission points in a single regulation, and all emission points regulated by the subject NESHAP are in a single source category.

### 2.1.2 *Miscellaneous Process Vent Provisions*

Miscellaneous process vents include vents from petroleum refining process units that emit organic HAP's. Vents that are



routed to the refinery fuel gas system are considered to be part of the process and are not subject to the standard. The miscellaneous process vent provisions define two groups of vents. Group 1 process vents are those with VOC emissions greater than or equal to 33 kilograms per day (kg/day) (72 lbs/day) at existing sources. Group 2 vents are vents with emissions below this level.

The miscellaneous process vent provisions for new and existing sources require the owner or operator of a Group 1 miscellaneous process vent to control vents using a flare, boiler, process heater, or 98 percent control device. No controls or monitoring are required for those vents already in Group 2. The process vent provisions are the same for both new and existing petroleum refinery sources.

### 2.1.3 *Storage Vessel Provisions*

The storage vessel provisions define two groups of vessels: Group 1 vessels are vessels with a design storage capacity and a maximum true vapor pressure above the values specified in the regulation. Group 2 vessels are all storage vessels that are not Group 1 vessels. The storage provisions require that one of the following control systems be applied to Group 1 storage vessels: (1) An internal floating roof (IFR) with proper seals; (2) an external floating roof (EFR) with proper seals; (3) an EFR converted to an IFR with proper seals; or (4) a closed vent system with a 95 percent efficient control device. The storage provisions give details on the type of seals required. Monitoring and compliance provisions for Group 1 vessels include periodic external visual inspections of vessels and roof seals, as well as less frequent internal inspections. If a closed vent system and control device is used for venting emissions from Group 1 storage vessels, the owner or operator must establish appropriate monitoring procedures. No controls or inspections are required for Group 2 storage vessels.

For existing sources, the final rule requires that fixed roof tanks with capacities greater than or equal to 177 cubic meters (m<sup>3</sup>) (1,115 barrels or 47,000 gallons) that store liquids with

vapor pressures greater than 10.2 kilopascals (kPa) (1.5 pounds per square inch absolute (psia)) comply fully with the rule within 3 years. Owners or operators of IFR or EFR tanks are allowed to defer upgrading of their seals to meet the NESHAP requirements until the next scheduled inspection and maintenance activity or within 10 years, whichever comes first. For new sources, the final rule requires that vessels with capacities greater than or equal to 151 m<sup>3</sup> (950 barrels or 40,000 gallons), with vapor pressures equal to or greater than 3.4 kPa (0.5 psia), and vessels with capacities equal to or greater than 76 m<sup>3</sup> (475 barrels or 20,000 gallons) storing liquids with vapor pressures equal to or greater than 77 kPa (11.1 psia) comply with the level of control required by 40 CFR part 63 subpart G (including the controlled fitting requirements).

#### 2.1.4 Wastewater Provisions

The wastewater provisions of this rule are based on the benzene waste operations NESHAP (BWON), using benzene as a surrogate for all HAPs from wastewater in petroleum refineries. EPA research concluded that benzene is a good indicator of the presence of other HAPs. The wastewater streams subject to this rule include water, raw material, intermediate product, by-product, co-product, or waste material that contains HAPs and is discharged into an individual drain system. The wastewater provisions define two groups of wastewater streams. Group 1 streams are those that are located at a refinery with a total annual benzene loading of at least 10 megagrams per year and are not exempt from control requirements under 40 CFR 61 subpart FF (the BWON). In general, streams are not exempt from 40 CFR part 61 subpart FF if they contain a concentration of at least 10 parts per million by weight (ppmw) benzene, and have a flow rate of at least 0.02 liters per minute (l/min) (0.005 gallons per minutes (gal/min)). Group 2 streams are wastewater streams that are not Group 1.

The wastewater provisions of the final rule refer to the BWON for both new and existing sources, which requires owners or

operators of a Group 1 wastewater stream to reduce benzene mass by 99 percent using suppression followed by steam stripping, biotreatment, or other treatment processes. Vents from stream strippers and other waste management or treatment units are required to be controlled by a control device achieving 95 percent emissions reduction or 20 ppmv at the outlet of the control device. The performance tests, monitoring, reporting, and recordkeeping provisions required to demonstrate compliance are included in the BWON. No controls or monitoring are required for Group 2 wastewater streams.

#### *2.1.5 Equipment Leak Provisions*

The equipment leak standards for the petroleum refinery NESHAP allow owners and operators of existing sources to choose between complying with equipment leaks provisions in 40 CFR part 60 subpart VV (Petroleum Refinery NSPS Equipment Leaks Standard) or complying with a modified negotiated regulation for equipment leaks presented in 40 CFR part 63 subpart H (HON equipment leaks). The differences in the refinery equipment leak requirements and the HON equipment leak provisions are in the leak definitions and connector monitoring provisions.

Under either of the two options, existing refineries subject to the rule will be required to implement a Leak Detection and Repair (LDAR) program with the same leak definitions (10,000 ppm) and frequencies as specified in 40 CFR part 60 subpart VV within 3 years after promulgation of the petroleum refineries NESHAP. Refineries that choose to comply with the modified negotiated regulation would implement the Phase II leak definitions and frequencies at the end of the fourth year after promulgation, and comply with Phase III requirements 5 1/2 years after promulgation. Phase III has lower leak definitions, but allows less frequent monitoring for good performers. Although the modified negotiated regulation is not required in the final rule, the EPA believes that it would provide greater emission reductions and, in many cases, would be more cost effective than 40 CFR part 60 subpart VV and could even provide cost savings. Cost savings would occur because it would reduce equipment leak product loss, and facilities with a low percent of leaking valves

would be able to monitor less frequently, thereby reducing monitoring costs.

New sources must comply at startup with the modified negotiated regulation; pumps and valves at new sources must be in compliance with the Phase II requirements at startup rather than Phase I. This is consistent with the negotiated rule (40 CFR part 63 subpart H).

#### *2.1.6 Marine Vessel Loading and Unloading, Bulk Gasoline Terminal or Pipeline Breakout Station Storage Vessels, and Bulk Gasoline Terminal Loading Rack Provisions*

The final refineries NESHAP requires marine vessel loading and unloading operations at refineries to comply with the marine loading NESHAP (40 CFR part 63 subpart Y) unless they are included in an emissions average. Bulk gasoline terminal or pipeline breakout station storage vessel and equipment leaks, and bulk gasoline terminal loading racks at refineries are required to comply with the gasoline distribution NESHAP (40 CFR part 63 subpart R) unless they are included in an emissions average (equipment leaks cannot be included in an emissions average).

#### *2.1.7 Recordkeeping and Reporting Provisions*

The final rule requires petroleum refineries subject to 40 CFR part 63 subpart CC maintain required records for a period of at least 5 years. The final rule required that the following three types of reports be submitted: (1) a Notification of Compliance Status, (2) periodic reports, and (3) other reports.

#### *2.1.8 Emission Averaging*

The EPA is allowing emission averaging among existing miscellaneous process vents, refining storage vessels, and wastewater streams, marine vessel loading and unloading operations, bulk gasoline terminals or pipeline breakout station storage vessels and bulk gasoline terminal loading racks within a

refinery. New sources are not allowed to use emissions averaging. Under emission averaging, a system of emission "credits" and "debits" would be used to determine whether the source is achieving the required emission reductions.



### 3.0 NEED FOR REGULATION

One of the concerns about potential threats to human health and the environment from petroleum refineries is the emission of HAPs. Health risks from emissions of HAPs into the air include increases in cancer incidences and other toxic effects. This chapter discusses the need for and consequences of regulating of HAP emissions from petroleum refineries.

Section 3.1 presents the conditions of market failure which necessitate government intervention. Section 3.2 identifies the insufficiency of political and judicial forces to control the release of toxic air pollutants from petroleum refineries. Section 3.3 provides a characterization of the HAP and VOC emissions from petroleum refineries. These values represent the baseline against which the emission reductions associated with the regulatory options will be compared in the cost effectiveness calculations presented in Chapter 5 of this report. Section 3.3 also provides more detail on the health risks of these pollutants. Lastly, Section 3.4 identifies the consequences of regulating versus the option of not regulating.

#### 3.1 MARKET FAILURE

The U.S. Office of Management and Budget (OMB) directs regulatory agencies to demonstrate the need for a major rule.<sup>1</sup> The RIA must show that a market failure exists and that it cannot be resolved by measures other than Federal regulation. Market failures are categorized by OMB as *externalities*, *natural monopolies*, or *inadequate information*. The following paragraphs address the three categories of market failure.

### 3.1.1 Air Pollution as an Externality

Air pollution is an example of a negative externality. This means that, in the absence of government regulation, the decisions of generators of air pollution do not fully reflect the costs associated with that pollution. For a petroleum refiner, air pollution from the refinery is a product or by-product that can be disposed of cheaply by venting it to the atmosphere. Left to their own devices, many refiners treat air as a free good and do not fully "internalize" the damage caused by emissions. This damage is born by society, and the receptors - the people who are adversely affected by the pollution - are not able to collect compensation to offset their costs. They cannot collect compensation because the adverse effects, like increased risks of morbidity and mortality, are non-market goods, that is, goods that are not explicitly and routinely traded in organized free markets.

HAP emissions represent an externality in that refinery operation imposes costs on others outside of the marketplace. In the case of this type of negative externality, the market price of goods and services does not reflect the costs, borne by receptors of the HAPs, generated in the refining process. Government regulation can be used to improve the situation. For example, the NESHAP will force petroleum refiners to reduce the quantity of HAPs that they emit. With the NESHAP in effect, the amount that refiners must incur to refine petroleum products will more closely approximate the full social costs of production. In the long run, refiners will be forced to increase prices of the petroleum products sold in order to cover total production costs. Thus, prices will rise, consumers accordingly will reduce their demand for petroleum products, and as a result, fewer petroleum products will be provided to the market. The more the costs of pollution are internalized by the petroleum refiners, the greater the improvement in the way the market functions.

### 3.1.2 Natural Monopoly

Natural monopoly exists where a market can be served at lowest cost only if production is limited to a single producer. The



refining industry is characterized by some of the same attributes which define monopolistic markets, including economies of scale, and barriers to entry due to the heavy up-front capital needed for refinery construction. Because of the wide diversity in the size and number of petroleum refineries, however, conditions of natural monopoly do not represent a market failure for this industry.

### 3.1.3 *Inadequate Information*

The third category of potential market failure that sometimes is used to justify government regulation is inadequate information. Some petroleum refineries can reduce costs by installing air pollution control devices, or reducing leaks. Due to lack of information, some of these refineries do not install such systems. The NESHAP will require the collection of information that may give a particular petroleum refiner enough data to make an informed decision on whether or not control devices are the best option.

## 3.2 INSUFFICIENT POLITICAL AND JUDICIAL FORCES

There are a variety of reasons why many emission sources, in EPA's judgment, should be subject to reasonably uniform national standards. The principal reasons are:

- Air pollution crosses jurisdictional lines.
- The people who breathe the air pollution travel freely, sometimes coming in contact with air pollution outside their home jurisdiction.
- Harmful effects of air pollution detract from the nation's health and welfare regardless of whether the air pollution and harmful effects are localized.
- Uniform national standards, unlike potentially piecemeal local standards, are not likely to create artificial

incentives or artificial disincentives for economic development in any particular locality.

- One uniform set of requirements and procedures can reduce paperwork and frustration for firms that must comply with emission regulations across the country.

### 3.3 ENVIRONMENTAL FACTORS WHICH NECESSITATE REGULATION

Regulation of the petroleum refining industry is necessary because of the adverse health effects caused by human exposure to HAP emissions. This section characterizes the emissions attributable to petroleum refining and summarizes the adverse health effects associated with human exposure to HAP emissions.

#### 3.3.1 Air Emission Characterization

The HAP emissions from the emission points that comprise the source in this source category are all organic HAPs. Therefore, given the source and source category definitions, the provisions of this NESHAP apply to organic HAPs listed in section 112(b) of the CAA. HAP emissions from refineries are composed of a few chemicals, including benzene, toluene, xylenes, ethylbenzene, and hexane. There is a narrower range of variation in emission stream composition among petroleum refinery emission points than there is in some other source categories (e.g., Synthetic Organic Chemical Manufacturing Industry (SOCMI) emission points regulated by the HON). However, the different HAPs emitted have different toxicities, and there are some variations in the concentrations of individual HAPs and the emission release characteristics of different emission points.

Baseline emissions from petroleum refineries were estimated using information published in the *Oil and Gas Journal* (OGJ) and provided by petroleum refineries in response to information collection requests and questionnaires sent out under section 114 of the CAA. Table 3-1 presents the baseline HAP and VOC emissions for each of the four kinds of emission points controlled by this promulgated rule. Emission levels of other air pollutants (CO, NO<sub>x</sub>, and SO<sub>2</sub>) were not quantified. Baseline

emissions include emissions from both new and existing sources. Baseline HAP and VOC emissions take into account the current estimated level of emissions control, based on questionnaire responses submitted by refineries, and on related regulations which have already been promulgated. (These regulations are summarized later in this chapter.) As a result, baseline HAP and VOC emissions reflect the level of control that would be achieved in the absence of the promulgated rule.

TABLE 3-1. NATIONAL BASELINE VOC AND HAP EMISSIONS BY EMISSION POINT

Emission Point	Baseline Emissions (Mg/yr)	
	HAP	VOC
Miscellaneous Process Vents	10,000	109,000
Equipment Leaks	52,000	189,000
Storage Vessels	9,300	111,000
Wastewater Collection and Treatment	10,000	10,000
TOTAL	81,300	419,000

Given available data, it has not been possible to identify individual HAP emissions for each type of emission point. Speciated HAP emissions were available only for equipment leaks. Since HAP emissions from equipment leaks account for nearly 65 percent of total HAP emissions at petroleum refineries, however, this speciation is valuable for approximating the minimum level of cancer risk related to refinery emissions. Speciated HAP emissions for equipment leaks are presented in Table 3-2.

### 3.3.2 Harmful Effects of HAPs

Exposure to HAPs has been associated with a variety of adverse health effects. Direct exposure to HAPs can occur through inhalation, soil ingestion, the food chain, and dermal contact. Health effects associated with HAP emissions are addressed in these NESHAPs. Many HAPs are classified as known human carcinogens. Other HAPs have not been classified as known human carcinogens. Exposure to these pollutants, however, may still

result in adverse health and welfare impacts to human populations.

EPA has devised a system, which was adapted from one developed by the International Agency for Research on Cancer (IARC), for classifying chemicals based on the weight-of-evidence.<sup>2</sup> Of the HAPs listed in Table 3-2, only benzene is classified as group A, or a known human carcinogen. This means that there is sufficient evidence to support that the chemical causes an increased risk of cancer in humans. Benzene is a concern to the EPA because long term exposure to this chemical has been known to cause leukemia in humans. While this is the most well known effect, benzene exposure is also associated with aplastic anemia, multiple myeloma, lymphomas, pancytopenia, chromosomal breakages, and weakening of bone marrow (53 FR 28504; July 28, 1988).

Cresols is considered to be a group C or a possible human carcinogen. For this chemical, there is either inadequate data or no data on human carcinogenicity, and there is limited data on animal carcinogenicity. Therefore, while cancer risk is possible, there is not sufficient evidence to support that this chemical will cause increased cancer risks in humans. The remaining HAPs in Table 3-2 are noncarcinogens.

Though they do not cause cancer, they are considered hazardous because of the other significant adverse health effects with which they are associated. These other adverse health effects are listed in Chapter 8 of this RIA.

Emissions of VOC have been associated with a variety of health impacts. VOCs, together with NO<sub>x</sub>, are precursors to the formation of tropospheric ozone. It is exposure to ozone that is responsible for adverse respiratory impacts, including coughing and difficulty in breathing. Repeated exposure to elevated concentrations of ozone over long periods of time may also lead to chronic, structural damage to the lungs.

TABLE 3-2. BASELINE SPECIATED HAP EMISSIONS FROM EQUIPMENT LEAKS

Hazardous Air Pollutant	Baseline Emissions (Mg/yr)
2, 2, 4-Trimethylpentane	6,497
Benzene	2,190
Ethylbenzene	2,734
Hexane	6,309
Naphthalene	1,540
Toluene	9,256
Xylenes	8,737
Hydrogen Fluoride	3,178
Phenol	1,429
Cresols	693
MTBE	6,716
Hydrogen Chloride	229
Methyl Ethyl Ketone	2,435
TOTAL	51,943

### 3.4 CONSEQUENCES OF REGULATORY ACTION

This section provides an assessment of the consequences of the attainment of EPA emission reduction objectives, and the likely consequences if these objectives are not met.

#### 3.4.1 *Consequences if EPA's Emission Reduction Objectives are Met*

This section presents the environmental, cost, and energy use impacts resulting from the control of HAP emissions under the promulgated rule. (Economic impacts will be presented in Chapter 6.) It is estimated that approximately 173 petroleum refineries would be required to apply controls by the proposed standards. Throughout this report, impacts are presented relative to the baseline, which represents the level of control in the absence of the proposed rule. The estimates include the impacts of applying control to: (1) existing process units and (2) additional process units that are expected to begin operation over a 5-year period. Thus, the estimates represent annual impacts occurring in the fifth year. Based on a review of annual construction projects over the years 1988 to 1992 listed in the *Oil and Gas Journal*, it was assumed that 34 new process units would be constructed each year over a 5-year period.

3.4.1.1 *Allocation of Resources.* There will be improved allocation of resources associated with petroleum refining. Specifically, more of the costs of the harmful effects of the refining process will be internalized by the producers. This, in turn, will affect consumers' purchasing decisions. To the extent these newly-internalized costs are then passed along to the end users of refined petroleum products, and to the extent that these end users are free to buy as much or as little of the petroleum products as they wish, they will purchase less (relative to their purchases of other competing services). If this same process of internalizing negative externalities occurs throughout the entire petroleum refining industry, an economically optimal situation is

approached. This is the situation in which the marginal cost of resources devoted to petroleum refining equals the marginal value of the products to the end users of the products. Although there are uncertainties in this progression of impacts, in the aggregate and in the long run, the NESHAP will move society toward this economically optimal situation.

3.4.1.2 *Emissions Reductions.* The environmental impact of the rule includes the reduction of HAP and VOC emissions. Under the promulgated rule, it is estimated that the emissions of HAP from refineries would be reduced by 48,000 Mg/yr, and the emissions of VOC would be reduced by 252,000 Mg/yr. Emission levels of other air pollutants (CO, NO<sub>x</sub>, and SO<sub>2</sub>) were not quantified. It is important to note that the possibility exists for slight increases above existing emission levels for CO, NO<sub>x</sub>, and SO<sub>2</sub> may result from the combustion of fossil fuel as part of additional control device operations refineries undertake to meet the requirements of this NESHAP. Additional emissions of these pollutants would be attributable to the additional fuel burned to generate energy for operation of compressors for ducting miscellaneous process vent streams to control devices.

3.4.1.3 *Costs and Benefits.* The cost impact of the rule includes the capital cost of new control equipment, the associated operation and maintenance cost, and the cost of monitoring, recordkeeping, and reporting. Generally, the cost impact also includes any cost savings generated by reducing the loss of valuable product in the form of emissions. Under the promulgated rule, it is estimated that total capital costs would be \$213 million (first quarter 1992 dollars) and total annual costs would be \$79 million (first quarter 1992 dollars). Table 3-3 presents the capital and annual cost impact of the regulation for each of the four emission points as well as the national totals.

TABLE 3-3. NATIONAL CONTROL COST IMPACTS OF PREFERRED ALTERNATIVE IN THE FIFTH YEAR

Emission Point	Total Capital Costs (Million Dollars)	Total Annual Costs (Million Dollars)
Miscellaneous Process Vents	21.0	12.0
Equipment Leaks	142.0	58.0
Storage Vessels	48.0	8.0
Wastewater Collection and Treatment	a	a
Other recordkeeping and reporting	2.0	1.0
TOTAL	213.0	79.0

NOTES: <sup>a</sup>The MACT level of control is no additional control.

3.4.1.4 *Energy Impacts.* Increases in energy use were estimated for operating control equipment that would be required by the promulgated standards (compressors for ducting miscellaneous process vent streams to control devices). The estimated energy use increase in the fifth year would be 48 million kw-hr/yr of electricity or 77.5 thousand barrels of oil equivalent.<sup>3</sup>

3.4.1.5 *State Regulation and New Source Review.* State regulatory programs will be strengthened. Some components of the petroleum refining industry have already been subject to various Federal, State, and local air pollution control rules. Although these existing rules will remain in effect, the petroleum refinery NESHAP will provide comprehensive coverage of the petroleum refinery sources not covered by the existing rules. Recognition that the NESHAP is effectively reducing emissions will expedite the State process of reviewing applications for new petroleum refineries and issuing permits for their construction and operation. State regulations will also be uniform, and the disadvantages of the piecemeal approach to emission regulation will be avoided.



3.4.1.6 *Other Federal Programs.* The regulations which affect the petroleum refining industry that have already been promulgated include a number of NSPS, (40 CFR 60): subpart J - Standards of Performance for Petroleum Refineries; subparts K, Ka, and Kb - various standards of performance for storage vessels for petroleum liquids; subpart GGG - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries, and the Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems. The regulations that have already been promulgated also include a number of NESHAPs, (40 CFR 61): subpart J - NESHAP for Equipment Leaks (Fugitive Emission Sources) of Benzene; subpart Y - NESHAP for Benzene Emissions from Benzene Storage Vessels; and subpart FF - NESHAP for Benzene Waste Operations (BWON).

This petroleum refinery NESHAP generally covers refinery processes that produce petroleum liquids (such as motor gasoline, naphthas, and kerosene) for use as fuels. Often, products of refinery processes are used to make synthetic organic chemicals other than fuels. The petroleum refinery NESHAP will not cover chemical manufacturing process units that are covered under the SOCFI source category, even if these units are located at a refinery site. A SOCFI chemical manufacturing process unit that is located at a refinery and produces one or more of the chemicals listed in the HON (40 CFR 63 subpart F, table 1) as a single chemical product or as a mixed chemical used to produce other chemicals would be considered a SOCFI process and would be subject to the HON rather than to the petroleum refinery NESHAP.

#### 3.4.2 *Consequences if EPA's Emission Reduction Objectives are Not Met*

The most obvious consequence of failure to meet EPA's emission reduction objectives would be emissions reductions and benefits that are not as large as is projected in this report. However, costs are not likely to be as large either. Whether it is noncompliance from ignorance or error, or from willful intent, or simply slow compliance due to owners and/or operators exercising legal delays, poor compliance can save some refineries money.

Unless States respond by allocating more resources into enforcement, then poor compliance could bring with it smaller aggregate nationwide control costs. EPA has not included an allowance for poor compliance in its estimates of emissions reductions, due to the fact that poor compliance is unlikely. Also, if the emission control devices degraded rapidly over time or in some other way did not function as expected, there could be a misallocation of resources. This situation is very unlikely, given that the NESHAP is based on demonstrated technology.

## REFERENCES

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2. U.S. Environmental Protection Agency. The Risk Assessment Guidelines of 1986. Office of Health and Environmental Assessment. Washington, DC. August 1987.
3. U.S. Environmental Protection Agency. National Emission Standards for Hazardous Air Pollutants for Source Categories: Petroleum Refineries. Proposed Rule and Notice of Public Hearing. Draft. Section IV. February 1994.



#### 4.0 CONTROL TECHNIQUES AND REGULATORY ALTERNATIVES

The promulgated regulation would require a broad range of control techniques as options for compliance with the standard. Combustion technology, internal floating roofs, and product recovery devices, including internal floating roofs and vapor recovery tanks, are all part of the technology requirements for the Petroleum Refinery NESHAP. Leak detection and repair (LDAR) programs will be used to control equipment leaks. This chapter does not attempt to be comprehensive in explaining the technology and techniques used to control air toxics emissions under this promulgated regulation; it does attempt to survey what technologies and techniques are being used and how effective they are.

Petroleum refineries differ in the number, combination, and design of their process units; the production capacities of their refining processes; the type and characteristics of crude oil they use; and the control equipment they use. Consequently, actual emissions and characteristics of petroleum refinery facilities vary widely from refinery to refinery. This diversity affected the approach used to define the MACT floor for existing and new sources.

This chapter briefly explains the control technologies which are available to refineries to comply with the promulgated regulation. At the end of this chapter, a summary of the two regulatory alternatives is provided.

## 4.1 CONTROL TECHNIQUES

This section presents a summary of the control equipment available for combustion technology, product recovery devices, LDAR programs, and internal floating roofs. Each type of control is presented separately.

### 4.1.1 *Combustion Technology*

Combustion control devices, unlike noncombustion control devices, alter the chemical structure of the VOC. Destruction of the VOC by combustion is complete if all VOCs are converted to CO<sub>2</sub> and water. Incomplete combustion results in some of the VOC remaining unaltered or being converted to other organic compounds such as aldehydes or acids. If chlorinated or sulfur-containing compounds are present in the mixture, the products of complete combustion include the acid components HCl or SO<sub>2</sub>, respectively, in addition to water and carbon dioxide. Available combustion technology options include incinerators, flares, and boilers and process heaters. The process and applicability of each control type are summarized in the following sections.

4.1.1.1 *Incinerators.* Incineration is one of the best known methods of industrial gas waste disposal. It is a method of ultimate disposal, that is, the constituents to be controlled in the waste gas stream are converted rather than collected. Provided proper engineering design is used, incineration can eliminate the desired organic chemicals in a gas stream safely and cleanly.

The heart of an incinerator is a combustion chamber in which the VOC-containing waste stream is burned. The temperature required for combustion is much higher than the temperature of the inlet gas, so energy is usually supplied to the incinerator to raise the waste gas temperature. This is accomplished by adding auxiliary fuel (usually natural gas).

The amount of auxiliary fuel required can be decreased and energy efficiency increased by providing heat exchange between the inlet stream and the effluent stream. The effluent stream containing the products of combustion, along with any inerts that may have been present in or added to the inlet stream, can be

used to preheat the incoming waste stream, auxiliary air, or both via a "primary", or recuperative, heat exchanger.

Auxiliary air may be required for combustion if the requisite oxygen is not available in the inlet gas stream. Most industrial gases that contain VOCs are dilute mixtures of combustible gases in air.

Important in the design and operation of incinerators is the concentration of combustible gas in the waste gas stream. Having a large amount of excess air (i.e., in excess of the required stoichiometric amounts) may be costly, but any mixture within the flammability limits, on either the fuel-rich or fuel-lean side of the stoichiometric mixture, is considered a fire hazard as a feed stream to the incinerator. Therefore, some waste gas streams are diluted with air before incineration, even though this requires more fuel in the incinerator. There are two types of incinerators: thermal and catalytic. While much of what was discussed above applies to both, there are important differences in their design and operation.

4.1.1.1.1 *Thermal Incinerators.* As is true of other combustion control devices, thermal incinerators operate on the principle that any VOC heated to a high enough temperature in the presence of sufficient oxygen will be oxidized to CO<sub>2</sub> and water. The theoretical temperature for thermal oxidation depends on the properties of the VOC to be combusted. There is great variation in theoretical combustion temperatures among different VOCs.

There are three requirements that must be met for a thermal incinerator to be considered efficient: 1) a high enough temperature within the combustion chamber to enable oxidation of the organic compounds to proceed rapidly to completion; 2) enough turbulence for good mixing of the hot combustion products from the burner, the combustion air, and the organic compounds; and 3) sufficient residence time for oxidation to reach completion.

A typical thermal incinerator is a refractory-lined chamber containing a burner or set of burners at one end. Entering gases are mixed with the process vent streams and the inlet air in a premixing chamber. Then the stream of gases passes into the main combustion chamber. This chamber is designed to allow the

mixture enough time at the required combustion temperature for complete oxidation (usually from 0.3 to 1.0 second). A heat recovery section is often added to increase energy efficiency. Often, inlet combustion air is preheated; if this occurs, insurance regulations require the VOC concentration must be maintained below 25 percent of the lower explosive limit (LEL) to minimize the possibility of explosions. Concentrations from 25 to 50 percent are permitted given continuous monitoring by LEL monitors.

The required level of VOC control of the waste gas that must be achieved within the time it spends in the thermal combustion chamber dictates the reactor temperature. The shorter the residence time, the higher the reactor temperature must be. Once the unit is designed and built, the residence time is not easily changed, so that the required reaction temperature becomes a function of the particular gaseous species and the desired level of control. These required combustion reaction temperatures cannot be calculated a priori, although incinerator vendors can provide guidelines based on their extensive experience. Predictions of these temperatures are further complicated by the fact that most process vent streams are mixtures of compounds.

Good mixing is also important, particularly in determining destruction efficiency. Even though it cannot be measured, mixing is a factor of equal or even greater importance than other parameters such as temperature. The most feasible and efficient way to improve the mixing in an incinerator is to adjust it after start-up.

Other parameters affecting thermal incinerator performance are the heat content of the vent stream, the water content of the stream, and the amount of excess combustion air (the amount of air above the stoichiometric air needed for combustion). Combustion of a vent stream with a heat content less than 1.9 MJ/m<sup>3</sup> (52 BTU/scf) usually requires burning supplemental fuel to maintain the desired combustion temperature.

The maximum achievable VOC destruction efficiency decreases with decreasing inlet VOC concentration because combustion is slower at lower inlet concentrations. Therefore, a VOC weight



percentage reduction based on the mass rate of VOC exiting the control device versus the mass rate of VOC entering the device is appropriate for vent streams with VOC concentrations above approximately 2,000 ppmv (which corresponds to 1,000 ppmv VOC in the incinerator inlet stream since air dilution is typically 1:1).

Thermal incinerators are technically feasible control devices for most vent streams. They are not recommended, however, for vent streams with potentially excessive fluctuations in flow rate (process upsets, for example), and for vent streams containing halogens. The former case would require a flare (see Section 4.1.1.2) and the latter case would require additional equipment such as acid gas scrubbers (see Section 4.1.2).

4.1.1.1.2 *Types of Thermal Incinerators.* The very simplest type of thermal incinerator is the direct flame incinerator, which is made up of only the combustion chamber. Energy recovery devices such as a waste gas preheater and a heat exchanger are not included with this type of incinerator.

A second type of thermal incinerator is the recuperative model. Recuperative incinerators use the exit (product) gas to preheat the incoming feed stream, combustion air, or both via a heat exchanger. These heat exchangers can recover up to 70 percent of the energy (or enthalpy) in the product gas. The two types of heat exchangers commonly used for this purpose and many others are plate-to-plate and shell-and-tube. Plate-to-plate exchangers can be built to achieve a variety of efficiencies and offer high efficiency energy recovery at lower cost than shell-and-tube designs. But when gas temperatures exceed 520 degrees Celsius, shell-and-tube exchangers usually have lower purchase costs than plate-to-plate designs. Moreover, shell-and-tube exchangers offer better long-term structural reliability than plate-to-plate units.

Occasionally it is desired to recover some of the energy added by auxiliary fuel in the traditional thermal units (but not recovered in preheating the feed stream). Additional heat exchangers can be added to provide process heat in the form of low pressure steam or hot water for on-site application. The

need for this higher level of energy recovery will be dependent upon the plant site. The additional heat exchanger is often provided by the incineration unit vendor.

A third type of thermal incinerator is the regenerative incinerator. This type of incinerator uses direct contact heat exchangers constructed of a ceramic material that can tolerate the high temperatures needed to achieve ignition of the waste stream. The concept behind this incinerator type is that the traditional approach to energy recovery in thermal units still requires a significant amount of auxiliary fuel to be burned in the combustion chamber when waste gas heating values are too low to sustain the desired reaction temperature at the moderate preheat temperature employed. Under these conditions, additional fuel savings can be realized in units with more complete transfer of exit stream energy. The regenerative incinerator serves this purpose.

In this type of incinerator, the inlet gas first passes through a hot ceramic bed thereby heating the steam to its ignition temperature. After the hot gases react and release energy in the combustion chamber, the gases pass through another ceramic bed, thereby heating it to the levels of the combustion chamber outlet temperature. The process flows are then switched, now feeding the inlet stream to the hot bed. This cyclic process affords very high energy recovery (up to 95 percent).

4.1.1.1.3 *Catalytic Incinerators*. A catalyst promotes oxidation of some VOCs at a lower temperature than that required for thermal incineration. The catalyst increases the rate of the chemical reaction without becoming permanently altered itself. Catalysts typically used for VOC incineration include platinum and palladium. These catalysts work well for most organic streams, but are not tolerant of compounds containing halogens such as chlorine, and sulfur. Among the catalysts that have been developed that are effective in the presence of these halogens are chromia/alumina, cobalt oxide, and copper oxide/manganese oxide. Inert substrates are coated with thin layers of these materials to provide maximum surface area for contact with the VOC in the vent stream. Compounds containing elements such as

lead, arsenic, and phosphorus should, in general, be considered poisons for most oxidation catalysts. In addition, particulate matter, including dissolved minerals in aerosols, can rapidly blind (deactivate) the pores of catalysts and deactivate them over time. Because essentially all the active surface of the catalyst is contained in relatively small pores, the particulate matter need not be large to blind the catalyst.

For optimal operation, the volumetric gas flow rate and the concentration of combustibles (in this case, VOCs) should be constant. Large fluctuations in the flow rate will cause the conversion of the VOCs to fluctuate also. Changes in the concentration or type of organic compounds in the gas stream can also affect the overall conversion of the VOC contaminants. Most changes in flow rate, organic concentration, and chemical composition are generally the result of upsets in the manufacturing process generating the waste gas stream.

Applicability of catalytic incinerators for control of VOCs is limited by the catalyst deactivation sensitivity to the characteristics of the inlet gas stream. The vent stream to be combusted should not contain materials that can poison the catalyst or deposit on and block the reactive sites on the catalyst surface. In addition, catalytic incinerators are unable to handle high inlet concentrations of VOC or very high flow rates. Catalytic incineration is generally useful for concentrations of 50 to 10,000 ppmv, if the total concentration is less than 25 percent of the LEL and for flow rates of less than 2,820 m<sup>3</sup>/min (100,000 scfm).

4.1.1.1.4 *Types of Catalytic Incinerators.* One type of catalytic incinerator is fixed-bed. Fixed-bed incinerators come in two varieties, depending on the type of catalyst used: the monolith and packed-bed. The monolith catalyst is the most widespread method of contacting the VOC-containing stream with the catalyst. In this scheme, the catalyst is a porous solid block containing parallel, non-intersecting channels aligned in the direction of the gas flow. Monolith catalysts offer the advantages of minimal attrition due to thermal

expansion/contraction during startup/shutdown and low overall pressure drop.

A second contacting scheme is a simple packed-bed in which catalyst particles are supported either in a tube or in shallow trays through which the gases pass. The tray type arrangement is the more common packed-bed scheme due to the use of pelletized catalysts. This tray arrangement is preferred because pelletized catalysts can handle inlet streams containing contaminants such as phosphorus or silicon. The tube arrangement is not used widely due to its inherently high pressure drop compared with a monolith, and the breaking of catalyst particles due to thermal expansion when the confined catalyst bed is heated/cooled during startup/shutdown.

A third contacting pattern between the gas and catalyst is a fluid-bed. Fluid-beds have the advantage of very high mass transfer rates, although the overall pressure drop is somewhat higher than for a monolith. Fluid-beds also possess the advantage of high bed-side heat transfer compared with a normal gas heat transfer coefficient. This higher heat transfer rate to heat transfer tubes immersed in the bed allows higher heat release rates per unit volume of gas processed and therefore may allow waste gases with higher heating values to be processed without exceeding maximum permissible temperatures in the catalyst bed. The catalyst temperatures depend on the rate of reaction occurring at the catalyst surface and the rate of heat exchange between the catalyst and imbedded heat transfer surfaces.

In general, fluid-bed systems are more tolerant of particulates in the gas stream than fixed-bed or packed-bed systems. This results from the constant abrasion of the fluidized catalyst pellets, which helps remove these particulates from the exterior of the catalysts in a continuous manner.

4.1.1.2 *Flares*. Flaring is an open combustion process in which the oxygen necessary for combustion is provided by the air around the flame. The organic compounds to be combusted are piped to a remote, usually elevated, location and burned in an open flame in the open air using a specially designed burner tip,

auxiliary fuel, and sometimes steam or air to promote mixing for nearly complete (98 percent minimum) destruction of combustibles. Good combustion in a flare is governed by flame temperature, residence time of organic species in the combustion zone, turbulent mixing of the organic species to complete the oxidation reaction, and the amount of oxygen available for free radical formation. Combustion is complete if all combustibles (i.e., VOCs) are converted to CO<sub>2</sub> and water, while incomplete combustion results in some of the VOCs being unaltered or converted to other organic compounds such as aldehydes or acids.

Flares are generally categorized in two ways: 1) by the height of the flare tip (i.e., ground-level or elevated), and 2) by the method of enhancing mixing at the flare tip (i.e., steam-assisted, air-assisted, pressure-assisted, or unassisted). Elevating the flare can prevent potentially dangerous conditions at ground level where the open flame is located near a process unit. Further, the products of combustion can be dispersed above working areas to reduce the effects of noise, heat radiation, smoke, and objectionable odors.

In most flares, combustion occurs by means of a diffusion flame. A diffusion flame is one in which air diffuses across the boundary of the fuel/combustion product stream toward the center of the fuel flow, forming the envelope of a combustible gas mixture around a core of fuel gas. This mixture, on ignition, establishes a stable flame zone around the gas core above the burner tip. This inner gas core is heated by diffusion of hot combustion products from the flame zone.

Cracking can occur with the formation of small hot particles of carbon that give the flame its characteristic luminosity. If there is an oxygen deficiency and if the carbon particles are cooled to below their ignition temperature, smoking occurs. In large diffusion flames, combustion product vortices can form around burning portions of the gas and shut off the supply of oxygen. This localized instability causes flame flickering, which can be accompanied by soot formation.

Flares can be dedicated to almost any VOC stream, and can handle fluctuations in VOC concentration, flow rate, heating

value, and inerts content. Flaring is appropriate for continuous, batch, and variable flow vent stream applications.

Some streams, such as those containing halogenated or sulfur-containing compounds, are usually not flared because they corrode the flare tip or cause formation of secondary pollutants (such as acid gases or sulfur dioxide). If these vent types are to be controlled by combustion, thermal incineration, followed by scrubbing to remove the acid gases, is the preferred method.

The majority of refineries have existing flare systems designed to relieve emergency process upsets that might contain large gas volumes. Often, large diameter flares designed to handle emergency releases are also used to control continuous vent streams from various process operations. Typically in refineries, many vent streams are combined in a common gas header to fuel boilers and process heaters. However, excess gases, fluctuations in flow rate in the fuel gas line, and emergency releases are sometimes sent to a flare. Five factors affecting flare combustion efficiency are vent gas flammability, auto-ignition temperature, heat content of the vent stream, density, and flame zone mixing.

The flammability limits of the vent stream influence ignition stability and flame extinction. Flammability limits are the stoichiometric composition limits (maximum and minimum) of an oxygen-fuel mixture that will burn indefinitely at given conditions of temperature and pressure without further ignition. In other words, gases must be within their flammability limits to burn. If these limits are narrow, the interior of the flame may have insufficient air for the mixture to burn. Fuels, such as hydrogen, with wide limits of flammability are therefore easier to combust.

The auto-ignition temperature of a vent stream affects combustion because gas mixtures must be at a sufficient temperature and concentration to burn. A gas with a low auto-ignition temperature will ignite more easily than a gas with a high auto-ignition temperature.

The heat content of the vent stream is a measure of the heat available from the combustion of the VOC in the vent stream. The

heat content of the vent stream affects the flame structure and stability. A gas with a lower heat content produces a cooler flame that does not favor combustion kinetics and is more easily extinguished. The lower flame temperature will also reduce buoyant forces, which reduces mixing.

The density of the vent stream also affects the structure and stability of the flame through the effect on buoyancy and mixing. By design, the velocity in many flares is very low; therefore, most of the flame structure is developed through buoyant forces as a result of combustion. Lighter gases therefore tend to burn better. In addition to burner tip design, the density also affects the minimum purge gas required to prevent flashback, with lighter gases requiring more purge.

Poor mixing at the flare tip or poor flare maintenance can cause smoking (particulate matter release). Vent streams with high carbon-to-hydrogen ratios ( $> 0.35$ ) have a greater tendency to smoke and require better mixing to burn smokelessly. For this reason, one generic steam-to-vent-stream ratio is not appropriate for all vent streams. The steam required depends on the vent stream carbon-to-hydrogen ratio. A high ratio requires more steam to prevent a smoking flare.

The efficiency of a flare in reducing VOC emissions can be variable. For example, smoking flares are far less efficient than properly operated and maintained flares. Flares have been shown to have high VOC destruction efficiencies, under proper operating conditions. Up to 99.7 percent combustion efficiency can be achieved.

4.1.1.2.1 *Steam-Assisted Flares.* Steam-assisted flares are single burner tips, elevated above ground level for safety reasons, that burn the vented gas in essentially a diffusion flame. They reportedly account for the majority of the flames installed and are the predominant flare type found in refineries. To ensure an adequate air supply and good mixing, this type of flare system injects steam into the combustion zone to promote turbulence for mixing and to induce air into the flame.

4.1.1.2.2 *Air-Assisted Flares.* Air-assisted flares use forced air to provide the combustion air and the mixing required

for smokeless operation. These flares are built with a spider-shaped burner (with many small gas orifices) located inside but near the top of a steel cylinder two feet or more in diameter. Combustion air is provided by a fan in the bottom of the cylinder, and the amount of combustion air can be varied by changing the fan speed. The primary advantage air-assisted flares provide is that they can be used without steam.

4.1.1.2.3 *Non-Assisted Flares.* The non-assisted flare is just a flare tip without any auxiliary provision for enhancing the mixing of air into its flame. Its use is limited essentially to gas streams that have a low heat content and a low carbon/hydrogen ratio that burn readily without producing smoke. These streams require less air for complete combustion, have lower combustion temperatures that minimize cracking reactions, and are more resistant to cracking.

4.1.1.2.4 *Pressure-Assisted Flares.* This type of flare uses vent stream pressure to promote mixing at the burner tip. If sufficient vent stream pressure is available, these flares can be applied to streams previously requiring steam or air assist for smokeless operation. Pressure-assisted flares generally have the burner arrangement at ground level, and consequently, must be located in a remote area of the plant where there is plenty of space available. They have multiple burner heads that are staged to operate based on the quantity of gas being released. The size, design, number, and group arrangement of the burner heads depend on the vent gas characteristics.

4.1.1.2.5 *Enclosed Ground Flares.* The burner heads of an enclosed flare are inside an insulated shell. This shell reduces noise, luminosity, and heat radiation and provides wind protection. A high nozzle pressure drop is usually adequate to provide the mixing necessary for smokeless operation and air or steam assist is not required. In this context, enclosed flares can be considered a special class of pressure-assisted or non-assisted flares. Enclosed flares are always at ground level.

Enclosed flares generally have less capacity than open flares and are used to combust continuous, constant flow vent streams, although reliable and efficient operation can be attained over a



wide range of design capacity. Stable combustion can be obtained with lower heat content vent gases than is possible with open flare designs, probably due to their isolation from wind effects.

4.1.1.3 *Boilers and Process Heaters.* Industrial boilers are combustion units that boil water to produce high and low pressure steam. Industrial boilers can also combust various vent streams containing VOCs, including vent streams from distillation operations, reactor processes, and other general operations. The majority of industrial boilers used in the refining industry are of watertube design, and over half of these boilers use natural gas as a fuel. In a watertube boiler, hot combustion gases contact the outside of heat transfer tubes which contain hot water and steam. These tubes are interconnected by a set of drums that collect and store the heated water and steam. Energy transfer from the hot flue gases to the water in the furnace watertube and drum system can be better than 85 percent efficient. Additional energy can be recovered from the flue gas by preheating combustion air in an air preheater or by preheating incoming boiler feed water in an economizer unit.

When firing natural gas, forced- or natural-draft burners thoroughly mix the incoming fuel and combustion air. A VOC-containing vent stream can be added to this mixture or it can be fed into the boiler through a separate burner. In general, burner design depends on the characteristics of the fuel - either the combined VOC-containing vent stream and fuel, or the vent stream alone (when a separate burner is used).

A process heater is similar to an industrial boiler in that heat liberated by the combustion of fuels is transferred by radiation and convection to fluids contained in tubular coils. It is different from an industrial boiler in that process heaters raise the temperature of process streams instead of producing high temperature steam. Process heaters are used in many chemical manufacturing operations to drive endothermic reactions. They are also used as feed preheaters and as reboilers for some distillation operations. The fuels used in process heaters include natural gas, refinery offgases, and various grades of fuel oil.

A typical process heater design consists of the burner(s), the firebox, and a row of tubular coils containing the process fluid. Most heaters also contain a convective section in which heat is recovered from hot combustion gases by convective heat transfer to the process fluid.

4.1.1.3.1 *Efficiency of Boilers and Process Heaters.* Average furnace temperature and residence time determine the combustion efficiency of boilers and process heaters, just as they do for incinerators. When a vent gas is injected as a fuel into the flame zone of a boiler or process heater, the required residence time is reduced because of the relatively high temperature and turbulence of the flame zone.

Residence time and temperature profiles in boilers and process heaters are determined by factors such as overall configuration, fuel type, heat input, and excess air level. A mathematical model developed to estimate furnace residence time and temperature profiles for a variety of industrial boilers predicts mean furnace residence times ranging 0.25 to 0.83 second for natural gas-fired watertube boilers that range in size from 4.4 to 44 MW (15 to  $150 \times 10^6$  Btu/hr). Boilers with a 44-MW capacity or greater generally have residence times and operating temperatures that would ensure a 98 percent VOC destruction efficiency. The required temperatures for these size boilers are at least 1,200 degrees Celsius.

Firebox temperatures for process heaters can show wide variations depending on the application. Firebox temperatures can range from 400 degrees Celsius for preheaters and reboilers to 1,260 degrees Celsius for pyrolysis furnaces. Tests conducted by EPA on process heaters using a mixture of benzene offgas and natural gas showed greater than 98 percent destruction efficiency for  $C_1$  to  $C_6$  hydrocarbons.

4.1.1.3.2 *Applicability of Boilers and Process Heaters.* Both of these devices are used throughout petroleum refineries to provide steam and heat input essential to the refining process. Most of these devices possess sufficient size to provide the necessary temperature and residence time for VOC destruction. Furthermore, boilers and process heaters have proved effective in

destroying compounds that are difficult to combust, such as PCBs (polychlorinated biphenyls). Boilers and process heaters are thus effective in reducing VOC emissions from any vent streams that are certain not to reduce the performance or reliability of the boiler or process heater.

Ducting some vent streams to a boiler or process heater can present potential safety and operating problems. The varying flow rate and organic content of some vent streams can lead to explosive mixtures or flame instability within the furnace. In addition, vent streams with halogenated or sulfur-containing compounds are usually not combusted in boilers or process heaters due to the possibility of corrosion.

Boilers and process heaters are most applicable where the potential exists for heat recovery from the combustion of the vent stream. Vent streams with a high enough VOC concentration and high flow rate can provide enough equivalent heat value to act as a substitute for fuel that would otherwise be needed.

#### 4.1.2 *Product Recovery Devices*

4.1.2.1 *Absorbers.* In absorption, a soluble vapor is absorbed from its mixture with an inert gas by means of a liquid in which the solute gas is more or less soluble. For any given solvent, solute, and operating conditions, there exists an equilibrium ratio of solute concentration in the gas mixture to solute concentration in the solvent. The driving force for mass transfer at a given point in an operating absorber is the difference between the concentration of solute in the gas and the equilibrium concentration of solute in the liquid.

Devices based on absorption principles include spray towers, venturi and wet impingement scrubbers, acid gas scrubbers, packed columns, and plate columns. Spray towers have the least effective mass transfer capability due to their high atomization pressure requirement, and are generally restricted to particulate matter removal and control of high-solubility gases such as SO<sub>2</sub> and NH<sub>3</sub> (ammonia). Venturi scrubbers have a high degree of gas/liquid mixing and provide high particulate matter removal efficiency. They also require high pressure drops (i.e. high

energy requirements) and have relatively short contact times. Their use is also restricted to high-solubility gases. Acid gas scrubbers are used with thermal incinerators to remove corrosive combustion products. Acid gas is formed upon the contact of halogenated or sulfur-containing VOCs with intense heat during incineration. This gas is quenched to lower its temperature and is then scrubbed in an absorber. In most cases, the type of absorber used is packed or plate columns, the two most commonly used absorbers for VOC control.

Packed towers are vertical columns containing inert packing, manufactured from materials such as porcelain, metal, or plastic, that provides the surface area for contact between the liquid and gas phases in the absorber. Packed towers are used mainly for corrosive materials and liquids with tendencies to foam or plug. They are also suitable where the use of plate columns would result in excessive pressure drops.

Plate columns contain a series of trays on which contact between the gas and liquid phases in a stepwise fashion. The liquid phase flows down tray to tray as the gas phase moves up through openings in the tray (usually perforations or bubble caps), passing through the liquid on the way.

The major design parameters for absorbing any substance are column diameter and height, system pressure drop, and required liquid flow rate. Deriving these parameters is accomplished by considering the solubility, viscosity, density, and concentration of the VOC in the inlet vent stream (all of which depend on column temperature); the total surface area provided by the packing material; and the mass flow rate of the gases to be treated.

4.1.2.1.1 *Absorber Efficiency.* Control efficiencies for absorbers can vary widely depending on the solvent selected, design parameters, and operating practices. Solvents are chosen for high solubility for the specific VOC and include liquids such as water, mineral oils, kerosenes, nonvolatile hydrocarbon oils, and aqueous solutions of oxidizing agents, sodium carbonate, and sodium carbonate. An increase in absorber size (i.e., contact surface area) or a decrease in the operating temperature can

increase the VOC removal efficiency of the system for a given solvent and solute. It is sometimes possible to increase VOC removal efficiency by changing the solvent.

4.1.2.1.2 *Applicability.* The primary determinant of absorption applicability for controlling VOC emissions is the availability of a suitable solvent. Water is a suitable solvent for absorption of organic chemicals with relatively high water solubilities (e.g., most alcohols, organic acids, aldehydes, glycols). For organic compounds with low water solubilities, other solvents (usually organic liquids with low vapor pressures) are used.

Other important factors influencing absorption applicability include absorptive capacity and strippability of VOC in the solvent. Absorptive capacity is a measure of the solubility of VOC in the solvent. The solubility limits the total quantity of VOC that could be absorbed in the system, while strippability describes the ease with which the VOC can be removed from the solvent. If strippability is low, then absorption is less viable as a VOC control technique.

The concentration of VOC in the inlet vent stream also determines the applicability of absorption. Absorption is usually considered only when the VOC concentration is above 200 to 300 ppm. Below these gas-phase concentrations, the rate of mass transfer of VOC to solvent is decreased enough to make reasonable designs infeasible.

4.1.2.2 *Carbon Adsorbers.* Adsorption is a mass-transfer operation involving interaction between gas- or liquid-phase components and solid-phase components. In this operation, certain components of a gas- or liquid-phase (or adsorbate) are transferred to the surface of a solid adsorbent. The transfer is accomplished by physical or chemical adsorption mechanisms. Physical adsorption takes place when intermolecular (van der Waals) forces attract and hold the gas molecules to the solid surface. Chemisorption occurs when a chemical bond forms between the gaseous- and solid-phase molecules. A physically adsorbed molecule can be removed readily from the adsorbent (under

suitable temperature and pressure conditions); the removal of a chemisorbed component is much more difficult.

Most industrial adsorption systems use activated carbon as the adsorbent. Activated carbon effectively captures certain organic vapors by physical adsorption. The vapors can then be released for recovery by regenerating the adsorption bed with steam or nitrogen. Oxygenated adsorbents such as silica gels or diatomaceous earth exhibit a greater selectivity for capturing water vapor than organic gases compared to activated carbon. They thus are of little use for high-moisture vent streams characteristic of some VOC-containing vent streams.

Among the factors influencing the design of a carbon adsorption system are the chemical characteristics of the VOC being recovered, the physical properties of the inlet stream (temperature, pressure, and volumetric flow rate), and the physical properties of the adsorbent. The mass of VOC that adheres to the adsorbent surface is directly proportional to the difference in VOC concentration between the gas phase and the solid surface. In addition, the quantity of VOC adsorbed depends on the adsorbent bed volume, the surface area of adsorbent available to capture VOC, and the rate of diffusion of VOC through the gas film at the gas- and solid-phase interface (the mass transfer coefficient). It should be noted that physical adsorption is an exothermic operation that is most efficient within a narrow range of temperature and pressure.

4.1.2.3.1 *Types of Adsorbers.* There are five types of adsorption equipment used in gas collection: 1) fixed regenerable beds; 2) disposable/rechargeable canisters; 3) traveling bed adsorbers; 4) fluid bed adsorbers; and 5) chromatographic baghouses. The fixed-bed type is the one most commonly used for control of VOCs, so this section addresses this type only.

Fixed-bed units can be sized for controlling continuous, VOC-containing streams over a wide range of flow rates, ranging up to several thousand cubic meters per minute (100,000 scfm). VOC concentrations in streams that can be treated by fixed-bed units

can range from several parts per billion by volume (ppbv) to 10,000 ppmv.

Fixed-bed adsorbers can be operated in two modes: intermittent or continuous. In intermittent mode, the adsorber removes VOCs for a specified time (called "the adsorption time"), which corresponds to the time during which the controlled source is emitting VOCs. In continuous mode, a regenerated carbon bed is always available for adsorption, so that the controlled source can operate continuously without shutting down. While continuous operation allows for more adsorption over the same period of time because it does not need to be shut down, more carbon must be provided. This is necessary since a bed for desorbing must be provided along with the adsorbing bed in order to recover the captured VOC from the carbon.

4.1.2.3.2 *Control Efficiency.* Well designed and operated carbon adsorption systems can achieve control efficiencies of 95 to 99 percent for a variety of solvents including ketones such as methyl ethyl ketone and cyclohexanone. The VOC control efficiency depends on factors such as inlet vent stream characteristics (temperature, pressure, and velocity), the physical properties of the compounds present in the vent stream, the physical properties of the adsorbent, and the condition of the regenerated carbon bed.

The adsorption capacity of the carbon and the resulting outlet concentration are dependent upon the temperature of the inlet vent stream. High vent stream temperatures increase the kinetic energy of the gas molecules, causing them to overcome van der Waals forces and release from the surface of the carbon. At vent stream temperatures above 38 degrees Celsius, both adsorption capacity and outlet concentration may be adversely affected.

Increasing vent stream pressure improves VOC removal efficiency. Increased stream pressure results in higher VOC concentrations in the vapor phase and increased driving force for mass transfer to the carbon surface. Decreased stream pressure, on the other hand, is often used to regenerate carbon beds. Reduced pressure in the carbon bed effectively lowers the

concentration of VOCs in the vapor phase, desorbing the VOCs from the carbon surface to the vapor phase.

Vent stream velocity entering the carbon bed must be quite low to allow time for diffusion and adsorption. Typical inlet vent stream velocities range from 15 to 30 meters per minute (50 to 100 feet per minute). If inlet VOC concentrations are low, the bed area required for the volume needed usually permits a velocity at the high end of this range. The required depth of the bed for a given compound is directly proportional to the carbon granule size and porosity and to the inlet vent stream velocity. For a given carbon type, bed depth must increase as the vent stream velocity increases. Generally, carbon adsorber bed depths range from 0.40 to 0.95 meter (1.5 to 3.0 feet). The condition of the regenerated carbon bed will change with use. After repeated regeneration, the carbon bed loses activity, resulting in reduced VOC removal efficiency.

4.1.2.3.3 *Applicability.* Carbon adsorption cannot be used universally for distillation or process vent streams. It is not recommended under the following conditions, common with many VOC-containing vent streams: 1) high VOC concentrations, 2) very high or low molecular weight compounds, 3) mixtures of high and low boiling point VOCs, and 4) high moisture content.

Absorbing vent streams with VOC concentrations above 10,000 ppmv may result in excessive temperature rise in the carbon bed due to the accumulated heat of adsorption resulting from the VOC loading. If flammable vapors are present, insurance company requirements may limit inlet concentrations to less than 25 percent of the LEL.

The molecular weight of the compounds to be adsorbed should be in the range of 45 to 130 gm/gm-mole for effective adsorption. High molecular weight compounds that are characterized by low volatility are strongly adsorbed on carbon. The affinity of carbon for these compounds makes it difficult to remove them during regeneration of the carbon bed. Conversely, highly volatile materials (i.e., molecular weight less than about 45 gm) do not adsorb readily on carbon, thus adsorption is not typically used for controlling streams containing such compounds.



Adsorption systems can be very effective with homogeneous vent streams but much less so with streams containing a mixture of light and heavy hydrocarbons. The lighter organic compounds tend to be displaced by the heavier compounds, greatly reducing system efficiency.

Humidity is not a factor in adsorption at adsorbate concentrations above 1,000 ppmv. Below this level, however, water vapor competes with VOCs in the vent stream for adsorption sites on the carbon surface. In these cases, vent stream humidity levels exceeding 50 percent (relative humidity) are not desirable.

4.1.2.4 *Condensers.* Condensation is a separation technique in which one or more volatile components of a vapor mixture are separated from the remaining vapors through saturation followed by a phase change. The phase change from gas to liquid can be achieved in two ways: 1) by increasing the system pressure at a given temperature or 2) by lowering the temperature at a constant pressure. The latter method is the more common to achieve the specified phase change, and it alone is addressed here.

The basic equipment includes a condenser, refrigeration unit(s), and auxiliary equipment such as a pre-cooler, recovery/storage tank, pump/blower, and piping. The two most commonly used condenser types are surface condensers and direct contact condensers. In surface condensers, the coolant fluid does not contact the vent stream; heat transfer occurs through the tubes or plates in the condenser. As the vapor condenses, a film forms on the cooled surface and drains away to a collection tank for storage, reuse, or disposal. Because the coolant from surface condensers does not contact the vapor stream, it is not contaminated and can be recycled in a closed loop. Surface condensers also allow for direct recovery of VOCs from the gas stream.

Most refrigerated surface condensers are the shell-and-tube type, which circulates the coolant fluid on the tube side. The VOCs condense on the outside of the tube (the shell side). Plate-type heat exchangers are also used as surface condensers in refrigerated systems. Plate condensers operate under the same

principles as the shell-and-tube systems, for there is no contact between the coolant and vent stream), but the two streams are separated by thin, flat plates instead of cylindrical tubes.

In contrast to surface condensers, direct contact condensers cool the vapor stream by spraying a liquid at ambient or lower temperature directly into the vent stream. Spent coolant containing VOCs from direct contact condensers usually cannot be reused directly. Additionally, VOCs in the spent coolant cannot be recovered without further processing. The combined stream creates a wastewater with potential for air emissions.

A refrigeration unit generates the low-temperature medium necessary for heat transfer for recovery of VOCs. Typically in refrigerated condenser systems two kinds of refrigerants are used, primary and secondary. Primary refrigerants such as ammonia and chlorofluorocarbons (e.g., chlorodifluoromethane) are those that undergo a phase change from liquid to gas after absorbing heat. Secondary refrigerants, such as brine solutions, have higher boiling points and thus act only as heat carriers and remain in the liquid phase.

There are some applications that require auxiliary equipment. If the vent stream contains water vapor or if the VOC has a high freezing point (e.g., benzene or toluene), ice or frozen hydrocarbons may form on the condenser tubes or plates. This will reduce the heat transfer efficiency of the condenser and thereby reduce the removal efficiency. Formation of ice will also increase the pressure drop across the condenser. In such cases, a precooler may be used to remove the moisture before the vent stream enters the condenser. Alternatively, ice can be melted during an intermittent heating cycle by circulating ambient temperature brine through the condenser or using radiant heating coils.

It is necessary in some cases to provide a recovery tank for temporary storage of condensed VOC before its reuse, reprocessing, or transfer to a large storage tank. Pumps and blowers are typically used to transfer liquid (e.g., coolant and recovered VOC) and gas streams, respectively, within the system.

4.1.2.4.1 *Control Efficiency.* The major parameters that affect the removal efficiency of refrigerated surface condensers designed to control air/VOC mixtures are: 1) Volumetric flow rate of the VOC-containing vent stream; 2) Inlet temperature of the vent stream; 3) Concentrations of the VOCs in the vent stream; 4) Absolute pressure of the vent stream; 5) Moisture content of the vent stream; and 6) properties of the VOCs in the vent stream, such as dew points, heats of condensation, heat capacities, and vapor pressures.

Any operator of a condenser should remember that a condenser cannot lower the VOC concentration to levels below the saturation concentration at the coolant temperature. Removal efficiencies above 90 percent can be achieved with coolants such as chilled water, brine solutions, ammonia, or chlorofluorocarbons.

4.1.2.4.2 *Applicability.* Condensers are widely used as product recovery devices. They may be used to recover VOCs upstream of other control devices or they may be used alone for controlling vent streams containing relatively high VOC concentrations (usually greater than 5,000 ppmv). In these cases, the removal efficiencies of condensers can range widely, from 50 to 95 percent.

Since the temperature necessary for condensation depends on the properties and concentration of VOCs in the vent stream, streams having either low VOC concentrations or more volatile compounds require lower condensation temperatures. Also, depending on the type of condenser used, disposal of the spent coolant can be a problem. If cross-media impacts are a concern, surface condensers would be preferable to direct contact condensers.

Condensers used as emission control devices can process flow rates as high as about 57 m<sup>3</sup>/min (120,000 scfm). Condensers for vent streams with greater volumetric flow rates and having high concentrations of noncondensibles will require significantly larger heat transfer areas.

#### 4.1.3 Leak Detection and Repair

Leak detection and repair (LDAR) programs have been required by EPA for a number of years. They have been undertaken to reduce emissions due to leaking equipment. These emissions occur when process fluid (liquid or gaseous) is released through the sealing mechanisms of equipment in the chemical plant. This section discusses the sources of equipment leak emissions and control techniques that can be applied to reduce emissions from equipment leaks, including the applicability of each control technique and its associated effectiveness in reducing emissions.

Many potential sources of equipment leak emissions exist in a refinery. The following sources are covered in this section: pumps, compressors, pressure relief devices, open-ended lines, sampling connections, systems process valves, connectors, and instrumentation systems.

The techniques for reducing emissions from equipment leaks are as diverse as the types of sources. The three major categories for techniques are: 1) equipment (modifications); 2) closed vent systems; and 3) work practices. The selection of a control technique and its effectiveness in reducing emissions depends on a number of factors including: 1) type of equipment; 2) equipment service (gas, light liquid, heavy liquid); 3) process variables influencing equipment selection (temperature, pressure); 4) process stream composition; and 5) costs.

4.1.3.1 *Pumps.* Pumps are used widely in the petroleum refining industry for the movement of organic liquids. Liquids transferred by pump can leak at the point of contact between the moving shaft and the stationary casing. Consequently, all pumps require a seal at the point where the shaft penetrates the housing in order to isolate the pumped fluid from the environment.

Two generic types of seals, packed and mechanical, are used on pumps. Packed seals can be used on both reciprocating and rotary action (centrifugal) pumps. A packed seal consists of a cavity (or "stuffing box") in the pump casing filled with packing material that is compressed with a packing gland to form a seal

around the shaft. Coolant is required to remove the frictional heat between the packing and shaft. The necessary lubrication is provided by a coolant that flows between the packing and the shaft. Deterioration of the packing can result in leakage of the process liquid.

Mechanical seals are limited in application to pumps with rotating shafts. There are single and double mechanical seals, with many variations to their basic design, but all have a lapped seal face between a stationary element and a rotating seal ring. In a single mechanical seal, the faces are held together by the pressure applied by a spring on the drive and by the pump pressure transmitted through the pumped fluid on the pump end. An elastomer O-ring seals the rotating face to the shaft. The stationary face is sealed to the stuffing box with another elastomer O-ring or gasket.

For double mechanical seals, two seals are arranged back-to-back, in tandem, or face to face. In the back-to-back arrangement, a closed cavity is created between the two seals. A seal liquid, such as water or seal oil, is circulated through the cavity. This seal liquid is used to control the temperature in the stuffing box. For the seal to function properly, the pressure of the seal liquid must be greater than the operating pressure of the pump. In this manner, any leakage would occur across the seal faces into the process or the environment.

Double mechanical seals are used in many process applications, but there are some conditions for which their use is not indicated. Such conditions include service temperatures above 260 degrees Celsius, and pumps with reciprocating shaft motion. Further, double mechanical seals cannot be used where the process fluid contains slurries, polymeric, or undissolved solids.

Another type of pump used in the petroleum refining industry is the seal-less pump. Seal-less pumps are used primarily in processes where the pumped fluid is hazardous, highly toxic, or very expensive and where every effort must be made to prevent all possible leakage of the fluid. Canned-motor, diaphragm, and magnetic drive pumps are three common types of seal-less pumps.

Canned-motor pumps have interconnected cavity housings, motor rotors, and pump casings. Because the process liquid is the bearing lubricant, abrasive solids in the process lines cannot be tolerated. Canned-motor pumps are widely used for handling organic solvents, organic heat transfer liquids, and light oils.

Diaphragm pumps contain a flexible diaphragm of metal, rubber, and plastic as the driving member. The primary advantage of this arrangement is the elimination of all packing and seals exposed to the process liquid provided the diaphragm's integrity is maintained. This is important when handling hazardous or toxic liquids. Emissions from diaphragm pumps can be large, however, if the diaphragm fails. In magnetic-drive pumps, no seals contact the process fluid. An externally-mounted magnet coupled to the pump motor drives the impeller in the pump casing.

4.1.3.2 *Compressors.* Compressors move gas through a process unit in much the same way that pumps transport liquid. Compressors are typically driven with rotating or reciprocating shafts. Thus, the sealing mechanisms for compressors are similar to those for pumps, i.e., packed and mechanical seals. Emissions from this source type may be reduced by improving the seals' performance or by collecting and controlling the emissions from the seal. Emissions from mechanical contact seals depend on the type of seal or control device used and the frequency of seal failure.

Shaft seals for compressors are of several different types: labyrinth, restrictive carbon rings, mechanical contact, and liquid film. All of these seal types restrict leaks, although none of them completely eliminates leakage. Compressors can be equipped with ports in the seal area to evacuate collected gases, which could then be controlled.

A buffer or barrier fluid may be used with these mechanical seals to form a buffer between the compressed gas and the environment, similar to barrier fluids in pumps. This system requires a clean, external gas supply that is compatible with the gas being compressed. Barrier gas can become contaminated and must be disposed of properly, for example by venting to a control device. Compressors can also be equipped with liquid film seals.

This seal is formed by a film of oil between the rotating shaft and stationary gland.

4.1.3.3. *Pressure Relief Devices.* Insurance, safety, and engineering codes require that pressure relief devices or systems be used in applications where the process pressure may exceed the maximum allowable working pressure of the process equipment. Pressure relief devices include rupture disks and safety/relief valves. The most common pressure relief device is a spring-loaded valve designed to open when the operating pressure of a piece of process equipment exceeds a set pressure. Equipment leak emissions from spring-loaded relief valves may be caused by failure of the valve seat or valve stem, improper reseating after overpressure relief, or process operation near the relief valve set pressure which may cause the relief valve to frequently open and close or "simmer."

Rupture disks are designed to burst at overpressure to allow the process gas to vent directly to the atmosphere. Rupture disks allow no emissions as long as the integrity of the disk is maintained. They must be replaced after each pressure relief episode to restore the process to an operating pressure condition. Although rupture disks can be used alone, they are sometimes installed upstream of a relief valve to prevent emissions through the relief valve stem.

Combinations of rupture disks and relief valves require certain design constraints and criteria to avoid potential safety hazards. For example, appropriate piping changes must be made to prevent disk fragments from lodging in damaging the relief valve when relieving overpressure. A block valve upstream of the rupture disk can be used to isolate the rupture disk/relief valve combination and permit in-service replacement of the disk after it bursts. Otherwise, emissions could result through the relief valve.

4.1.3.4 *Open-Ended Lines.* Emissions from open-ended lines are caused by leakage through the seat of an upstream valve in the open-ended line. Emissions that occur through the stem and gland of the valve are not considered "open-ended" emissions and are addressed in the section on process valves. Emissions from

open-ended lines can be controlled by installing a cap, plug, flange, or second valve to the open end. Control efficiency of these control measures is assumed to be 100 percent.

4.1.3.6 *Sampling Connections.* Emissions from sampling connections occur as a result of purging the sampling line to obtain a representative sample of the process fluid. These emissions can be reduced by using a closed loop sampling system or disposing of the purged process fluid in a control device. The closed loop sampling system is designed to return the purged fluid to the process at a point of lower pressure. Closed loop sampling is assumed to be 100 percent effective for controlling emissions from a sample purge. This purged fluid could also be directed to a control device such as an incinerator, in which case the control efficiency would depend on the efficiency of the incinerator in removing the VOC.

4.1.3.7 *Process Valves.* There are many designs for valves, and most of the designs contain a valve stem which operates to restrict or allow fluid flow. Typically, the stem is sealed by a packing gland or O-ring to prevent leakage of process fluid to the atmosphere. Emissions from valves occur at the stem or gland area of the valve body when the packing or O-ring in the valve fails.

Valves that require the stem to move in and out or turn must utilize a packing gland. A variety of packing materials are suitable for conventional packing glands. The most common packing materials are the various types of braided asbestos that contain lubricants; other packing materials include graphite, graphite-impregnated fibers, and tetrafluorethylene. The choice of packing material depends on the valve application and configuration. Conventional packing glands can be used over a wide range of operating temperatures.

Emissions from process valves can be eliminated if the valve stem can be isolated from the process fluid. There are two types of sealless valves available: diaphragm valves and sealed bellows valves.

Diaphragm valves isolate the valve stem from the process fluid using a flexible elastomer or metal diaphragm. The position of



the diaphragm is regulated by a plunger, which is controlled by the stem. Depending on the diaphragm material, this type of valve can be used at temperatures as high as 205 degrees Celsius and in strong acid service. If the diaphragm fails, the valve can become a relatively larger source of emissions. In addition, use at temperatures beyond the operating limits of the material tends to damage or destroy the diaphragm.

Sealed bellows valves are another alternative leakless design. In this valve type, metal bellows are welded to the bonnet and disk of the valve, thereby isolating the stem from the process. These valves can be designed to withstand high temperatures and pressures and can provide leak-free service at operating conditions beyond the limits of diaphragm valves. However, they are usually dedicated to highly toxic services and the nuclear industry.

The control effectiveness of both diaphragm and sealed bellows valves is essentially 100 percent, although a failure of the diaphragm or bellows could cause temporary emissions much larger than those from other types of valves.

4.1.3.8 *Connectors.* Connectors are flanges, threaded fittings, and other fittings used to join sections of piping and equipment. They are used wherever pipe or other equipment (such as vessels, pumps, valves, and heat exchangers) require isolation or removal.

Flanges are bolted, gasket-sealed connectors. Normally, flanges are used for pipes with diameters of 50 mm or greater and are classified by pressure rating and face type. The primary cause of flange leakage are poor installation and thermal stress, which results in the deformation of the seal between the flange faces.

Threaded fittings are made by cutting threads into the outside end of one piece (male) and the inside end of another piece (female). These male and female parts are then screwed together like a nut and bolt. Threaded fittings are normally used to connect piping and equipment having diameters of 50 mm or less. Seals for these fittings are made by coating the male threads with a sealant before joining it to the female piece. Emissions

from threaded fittings can occur as the sealant ages and eventually cracks. Leakage can also occur as the result of poor assembly or application of the sealant, and thermal stress of the piping and fittings.

Emissions from connectors can be controlled by regularly scheduled maintenance. Potential emissions can be reduced by replacing the gasket or sealant materials. If connectors are not required for process modification or periodic equipment removal, emissions from connectors can be eliminated by welding the connectors together.

4.1.3.9 *Instrumentation Systems.* An instrumentation system is a group of equipment components used to condition and convey a sample of process fluid to analyzers and instruments for the purpose of determining process operating conditions (e.g., composition, pressure, and flow rate). Valves and connectors are the predominant types of equipment used in instrumentation systems, although other equipment may be included. Emissions resulting from the components in the instrumentation system are controlled as they are for the same component in the process system.

Emissions from equipment leaks may be controlled by installed a closed vent system around the leaking equipment and venting the emissions to a control device. This method of control is only applicable to certain equipment types, i.e., pumps, compressors, agitators, pressure relief valves, and product accumulator vessels. Because of the many valves, connectors, and open-ended lines typically found in refineries, it is not practical to use this technique for reducing emissions from all of these potential sources for an entire process unit. However, a closed vent system can be used to control emissions from a limited number of components, which could be enclosed and maintained under negative pressure and vented to a control device.

LDAR methods are used to identify equipment components that are emitting significant amounts of VOC and to reduce these emissions. The emission reduction potential for LDAR as a control technique is highly variable and depends on several factors, the most important of which are the frequency of

monitoring and the techniques used to identify leaks. Repair of leaking components is required only when the equipment leak emissions reach a set level - the leak detection level. A low leak definition will initiate repair at lower levels, resulting in a lower overall emission rate.

Leak detection methods include individual component surveys, area (walk-through) surveys, and fixed point monitors. Individual component surveys form a part of the other methods.

4.1.3.9.1 *Individual Component Survey.* Each source of equipment leak emissions (pump, valve, compressor, etc.) can be checked for VOC leakage by visual, audible, olfactory, soap bubble, or instrument techniques. Visual methods are good for locating liquid leaks. A visible leak does not necessarily indicate VOC emissions, however, because the leaking material may be non-VOC. High-pressure leaks may be detected by the sound of escaping vapors, and leaks of odorous materials may be detected by smell.

Soap spraying on equipment components can be used to survey individual components in certain applications. If the soap solution forms bubbles or blows away, a leak is indicated, and vice versa. Disadvantages of this method are that 1) it does not distinguish leaks of hazardous VOCs from nonhazardous VOCs; 2) it is only semiquantitative, since it requires the observer to determine subjectively the rate of leakage based on the behavior of the soap bubbles; and 3) it is limited to sources with temperatures below 100 degrees Celsius, because the water in the soap solution will evaporate at temperatures above this figure. This method is also not suited for moving shafts on pumps or compressors, because the motion of the shaft may interfere with the motion of the bubbles caused by a leak.

The best method for identifying leaks of VOC from components is using a portable hydrocarbon detection instrument. Air close to the potential leak site is sampled and analyzed by a sampling traverse ("monitoring") over the entire area where leaks may occur. The concentration of hydrocarbons in the sampled air is displayed on the instrument meter and is a rough indicator of the VOC emission rate from the component. If the concentration is

higher than a specified figure ("action level"), then the leaking component is marked for repair.

4.1.3.9.2 *Repair Methods.* This section describes repair methods for possible equipment emission sources in a refinery. These are not intended to be complete repair procedures.

Many pumps have in-line or parallel spares that can be used while the leaking pump is being repaired. Leaks from packed seals may be reduced by tightening the packing gland. With mechanical seals, the pump must be dismantled to repair or replace the leaking seal. Dismantling pumps can result in spillage of some process fluid. If the seal leak is small, evaporative emissions of VOC from such spillage may be greater than the continued leak from the seal. Precautions must be taken to prevent or reduce these emissions.

Agitators, like pumps and compressors, can leak VOCs at the point where the shaft penetrates the casing, and seals are required to minimize fugitive emissions. Leaks from packed seals may be reduced by the repair procedure described for pumps, while repair of other types of seals require the agitator to be out of service. In this latter case, process shutdown or isolation of the particular agitator being repaired is required.

Leaking repair valves usually must be removed for repair. To remove the relief valve without shutting down the process, a block valve may be required upstream of the relief valve. A spare relief valve should be attached while the faulty valve is repaired and tested.

A rupture disk can be installed upstream from a pressure relief valve to eliminate leaks until an overpressure release occurs. Once a release occurs, the rupture disk must be replaced to prevent further leaks. A block valve is required to isolate the rupture disk for replacement.

Most valves have a packing gland that can be tightened while in service. Although this procedure should decrease the emissions from the valve, it can actually increase the emission rate if the packing is old and brittle or has been over-tightened. Some types of valves have no means of in-service repair and must be isolated from the process and removed for

repair and replacement. Most control valves have a manual bypass loop that allows them to be isolated and removed. Most block valves cannot be isolated easily, although temporary changes in process operation may allow isolation in some cases.

In some cases, leaks from connectors can be reduced by replacing the connector gaskets, but most connectors cannot be isolated to permit gasket replacement. Tightening of connector bolts also may reduce emissions from connectors. Where connectors are not required for process modification or periodic equipment removal, emissions from connectors can be eliminated by welding them.

#### 4.1.4 *Internal Floating Roofs*

Internal floating roofs are commonly used in the petroleum refining industry to control emissions from fixed-roof storage tanks. As the name implies, it is a roof inside a tank that floats on the surface of the stored liquid.

The presence of a floating roof (or deck) inside a fixed roof tank significantly reduces the surface area of exposed liquid. It serves as a physical barrier between the volatile organic liquid and the air that enters the tank through vents.

Because evaporation is the primary emission mechanism associated with storage tanks, emissions from floating roof tanks as well as fixed roof tanks vary with the vapor pressure of the stored liquid. Thus, the control efficiency of retrofitting a fixed roof tank with an internal floating deck depends on the material being stored.

Other factors affecting emissions, and therefore control efficiency, are tank size, number of turnovers, and the type of deck and seal system selected. Installing an internal floating roof can reduce emissions by 61 to 98 percent. The relative effectiveness of one internal floating roof design over another is a function of how well the deck can be sealed. Probably the most typical internal floating roof design is the noncontact, bolted, aluminum internal floating roof with a single vapor-mounted wiper seal and uncontrolled fittings.

Loss of VOCs from internal floating roof tanks occurs in one of four ways:

- 1) Through the annular rim space around the perimeter of the floating roof (seal losses),
- 2) Through the openings in the deck required for various types of fittings (fitting losses),
- 3) Through the nonwelded seams formed when joining sections of the deck material (deck seam losses), and
- 4) Through evaporation of liquid left on the tank wall following withdrawal of liquid from the tank (withdrawal loss).

4.1.4.1 *Control of Seal Losses.* Internal floating roof seal losses can be minimized by employing liquid-mounted primary seals instead of vapor-mounted seals and/or by employing secondary wiper seals in addition to primary seals.

Available emissions test data suggest that the location of the seal (i.e., vapor- or liquid-mounted) and the presence of a secondary seal are the major factors affecting seal losses. A liquid-mounted primary seal has a lower emissions rate, and thus a higher control efficiency, than a vapor-mounted seal. A secondary seal, with either a liquid- or a vapor-mounted primary seal, provides an additional level of control.

The type of seal used plays a less significant role in determining the emissions rate. The type of seal is important only to the extent that the seal must be suitable for the particular application. For instance, an elastomeric wiper seal is commonly employed as a vapor-mounted primary seal or as a secondary seal for an internal floating roof. Because of its shape, this seal is not suitable for use as a liquid-mounted primary seal. Resilient foam seals, on the other hand, can be used as both liquid- and vapor-mounted seals.

4.1.4.2 *Control of Fitting Losses.* There are numerous fittings that penetrate or are attached to an internal floating roof. Among them are access hatches, column wells, roof legs, sample pipes, ladder wells, vacuum breakers, and automatic gauge

float wells. Fitting losses occur when VOCs leak around these fittings. Fitting losses can be controlled with gasketing and sealing techniques or by the substitution of fittings that are designed to leak less.

The effectiveness of fitting controls at reducing the overall emission rate is a function of the number of fittings of each type employed on a given tank. For example, if using controlled fittings reduces total fitting loss by 36 percent, and if fitting losses are about 35 percent of the total emissions from a typical internal floating roof tank, then the controlled fittings reduce the overall emissions by  $(.36 \times .35) = .126$ , or 12.6 percent over a similar tank without fitting controls. The usual increase in control efficiency achieved by installing controlled fittings ranges from 0.5 to 1.0 percent.

4.1.4.3 *Control of Deck Seam Losses.* Deck seam losses are inherent in a number of floating roof types including internal floating roofs. Any roof constructed of sheets or panels fastened by mechanical fasteners (e.g., bolts) is expected to have deck seam losses. Deck seam losses are considered to be a function of the length of the seams and not the type of mechanical fastener or the position of the deck relative to the liquid surface. This is a conclusion drawn from a 1986 study on two roof types with significantly different mechanical fasteners and differences in the amount of contact with the liquid surface.

Deck seam losses are controlled by selecting a roof type with vapor-tight deck seams. The welded deck seams on steel pan roofs are vapor tight. Fiberglass lapped seams of a glass fiber reinforced polyester roof may be vapor tight as long as there is negligible permeability of the liquid through the seam lapping materials. Some manufacturers provide gaskets for bolted metal deck seams.

Selecting a welded roof (rather than a bolted roof) will eliminate deck seam losses. For a typical internal roof that has primary seals, secondary seals, and controlled fittings already, eliminating deck seam losses will raise the control efficiency as much as 1.5 percent.

4.1.4.4 *Applicability.* The applicability of any storage tank improvement in order to reduce VOC emissions is dependent upon the characteristics of the particular VOC. Since floating decks are often constructed primarily of aluminum, they may not be applicable to tanks storing halogenated compounds, pesticides, or other compounds that are incompatible with aluminum. Contact between these compounds and an aluminum deck could corrode the deck and cause product contamination.

In addition, vapor pressures may affect the selection of tank improvements as an applicable control technology. For chemicals with very low vapor pressure, fixed roof tank emissions will already be so low that installing an internal floating roof may not significantly reduce emissions further. For chemicals with vapor pressures up to 65 kPa (9.4 psia), emission reductions of 95 percent and above are achievable with this technology. Above this vapor pressure, achievable emission reduction starts to decrease with increasing vapor pressure. Thus, an internal floating roof may not be indicated for chemicals with relatively high vapor pressures.<sup>1</sup>

## 4.2 DESCRIPTION OF MACT AND SUMMARY OF REGULATORY ALTERNATIVES

The CAA requires that in designating regulatory options, the maximum degree of reduction in emissions that is deemed achievable shall be subject to a floor, which is determined differently for new and existing sources. For new sources, the standards must be set at levels which are not any less stringent than the emission control that is achieved in practice by the best controlled similar source. For existing sources, the standards may not be less stringent than the average emission limitation achieved by the best performing 12 percent of existing sources in each category or subcategory of 30 or more sources. In determining whether the standard should be more stringent than the floor and by how much, EPA is to consider, among other things, the cost of achieving such additional emission reductions. The options for achieving reductions at each



emission point are presented separately in the following sections. The chosen option and any more stringent options are presented separately for each of the four emission points.

#### 4.2.1 *Miscellaneous Process Vents*

This section summarizes the MACT floors and chosen alternatives as they relate to miscellaneous process vents and how they were arrived at. The EPA evaluated the current level of control for miscellaneous process vents in eight State and two air districts that contain the majority of refineries and were expected to have the most stringent regulations. Of the refineries in the U.S., the 12 percent that are subject to the most stringent regulations are located in three States. In these three States, miscellaneous process vents emitting greater than 15 to 100 lb/day (6.8 to 44.4 kg/day) of VOC are required to be controlled. The median applicability cutoff level for the 12 percent of U.S. refineries subject to the most stringent regulations is 72 lb/day (33 kg/day) VOC. Thus, control of process vents with VOC emissions greater than 72 lb/day is the MACT floor level of control for existing sources and is the standard for miscellaneous process vents. The primary organic HAPs at refineries are also VOC. Additionally, a VOC-based applicability criteria is most reflective of the current level of control required for miscellaneous process vents as the majority of State regulations are expressed in terms of VOC. Therefore, the EPA has adopted this emission level in the final rule to distinguish Group 1 from Group 2 vents. Group 1 vents, those that emit over 33 kg/day, must be controlled, whereas Group 2 vents, representing all other vents, are not required to apply controls under the final rule. The applicability limit is determined as gases exit from process unit equipment and not downstream from an emission control device. The new source MACT floor also includes reduction of emissions from miscellaneous process vents with the same cut-off.

#### 4.2.2 *Storage Vessels*

This section summarizes the MACT floors and chosen alternatives for storage vessels. The information that EPA used in determining the floor level of control for existing storage vessels consisted of the types of storage vessels, vessel capacities, existing controls on vessels, and true vapor pressures of stored liquids reported by refineries responding to survey questionnaires. EPA compared the baseline level of control on each storage vessel at each refinery with the storage vessel control requirements (with the exception of fitting requirements for floating roof vessels) of subpart Kb of 40 CFR 60. Subpart Kb represents the best control technology for storage vessels. It requires either floating roofs with specified seals and fittings or closed vent systems and control devices.

Once the best performing 12 percent were identified, the average true vapor pressure of the stored liquids being controlled at these refineries was determined. The MACT floor level of control for existing sources is: vessels with capacities greater than or equal to 177 cubic meters (1,115 barrels or 47,000 gallons) storing liquids with true vapor pressures greater than or equal to 23 kilopascals (kPa) (1.5 psia) must be controlled to the requirements of subpart Kb with the exception of the controlled fitting requirements for floating roof vessels. EPA determined, based on the available data, that an emission reduction more stringent than the level associated with the floor is not cost effective.

To determine the MACT floor for storage vessels at new sources, EPA reviewed other State and Federal storage vessel regulations. The MACT floor and an option more stringent than the floor requiring control of storage vessels with vapor pressures above 0.014 kPa (0.002 psia) (which is the same as option 3 for existing sources) was also considered. The level of control for new sources is the MACT floor. Vessels with capacities greater than or equal to 151 m<sup>3</sup> (950 barrels or 40,000 gallons) storing liquids with true vapor pressures greater than or equal to 3.4 kPa (0.5 psia), and vessels with capacities greater than or equal to 76 m<sup>3</sup> (475 barrels or 20,000 gallons)

storing liquids with vapor pressures equal to or greater than 77 kPa (11.1 psia) would be required to comply with the subpart Kb (including the controlled fitting requirements). The option more stringent than the floor was not selected because it would result in high costs relative to HAP emission reductions.

#### 4.2.3 Wastewater Streams

This section summarizes the MACT floors and chosen alternatives for wastewater streams. The alternative selected is the floor level of control (compliance with the Benzene Waste Operations NESHAP (BWON)). The BWON controls 75 percent of the benzene in refinery wastewater and 76 percent of the volatile organic HAP in refinery wastewater. The best performing wastewater control systems are those that are in place to comply with the BWON. These systems control not only benzene, but also the other organic HAPs in petroleum refinery wastewater. Benzene is an effective surrogate for indicating the presence of all HAP compounds in petroleum refinery wastewater because data show that the majority of the total HAP compound loading in wastewater consists of compounds that are very similar to benzene in terms of both chemical structure and volatility (from the water phase to the air phase).

Because the final standard for wastewater requires compliance with the existing BWON, no additional emission reduction, cost, energy, or other environmental or health impacts are associated with the standard. Based on data provided to the EPA through the BWON 90-day reports, the EPA determined that the BWON was applicable to 43 percent of the refineries. No refineries are known to have more stringent controls than the BWON. Therefore, the MACT floor, or the average of the top performing 12 percent of sources, is control to the BWON level of control.

EPA also considered an alternative level of emission reduction more stringent than the MACT floor that would be achieved by controlling all wastewater streams with at least 10 ppmw benzene at any refinery regardless of the size of its annual benzene loading. This alternative control option was not selected

because the additional emission reduction achieved through further control was not significant, given the associated costs.

The floor alternative was selected as the promulgated level of control for new sources. As with existing sources, the option more stringent than the floor was considered, but was rejected for new sources for the same reason described above for existing sources.

#### 4.2.4 *Equipment Leaks*

The section summarizes the MACT floors and chosen alternatives for equipment leaks. The Petroleum Refinery NSPS requirements (40 CFR part 60 subpart VV) is the MACT floor for existing sources. In the final rule, EPA is providing each existing refinery with a choice of complying with either: 1) The Petroleum Refinery NSPS equipment leak requirements mentioned above or 2) a modified version of the negotiated rule (40 CFR part 63 subpart H). The modified negotiated regulation is the same as what was contained in the proposed petroleum refinery NESHAP, except that the compliance dates have been extended. Although not required in the final rule, the EPA promotes use of the modified negotiated rule option because it is believed to provide considerable product, emissions, and cost savings to a refinery.

Under either option, existing refineries will be required to implement an LDAR program with the same leak definitions (10,000 ppm) and the same leak frequencies as contained in the NSPS by 3 years after promulgation. A refinery may opt to remain at this level of control and do the monitoring, recordkeeping, and reporting specified in the NSPS. This option allows refineries that are familiar with the Petroleum Refinery NSPS to continue to implement that standard without needing to change their procedures.

Alternatively, a refinery may choose to comply with Phase I of the negotiated rule (10,000 ppm leak definition) 3 years after promulgation, comply with Phase II 4 years after promulgation, and comply with Phase III 5 1/2 years after promulgation. Each phase has lower leak definitions for pumps and valves.

For new sources, EPA requires refinery sources to meet the same requirements as for existing sources.

#### 4.2.5 *Summary of Alternatives*

Based on the determination of the MACT floor for each of the four emission points, EPA selected a regulatory alternative. Alternative 1, the regulatory alternative selected, incorporates MACT floor level control for wastewater streams, storage vessels, and miscellaneous process vents, and the floor for equipment leaks. Table 4-1 presents a summary of the alternative examined in this analysis.

#### 4.3 NO ADDITIONAL EPA REGULATION

E.O. 12866 requires that the rationale for regulation versus no regulation must be addressed in the decision process. To satisfy this requirement, this section presents the alternatives to regulation of HAP emissions from petroleum refineries. The alternatives include reliance on the judicial system for pollution control, or reliance on regulation by States and localities.

##### 4.3.1 *Judicial System*

In the absence of governmental regulation, market systems fail to make the generators of pollution pay for the costs associated with that pollution. For an individual firm, pollution is an apparently unusable by-product that can be disposed of cheaply by venting it to the atmosphere. However, in the atmosphere, pollution causes real costs to others. The fact that producers, consumers, and others whose activities result in air pollution do not bear the full costs of their actions leads to a divergence between private costs and social costs. This divergence is considered a market failure, since it results in a misallocation of society's resources. Too many resources are devoted to the polluting activity when polluters do not bear the full cost of their actions.

TABLE 4-1. SUMMARY OF REGULATORY ALTERNATIVES BY EMISSION POINT

Emission Point	Alternative 1	Description of Control Option
Equipment Leaks	Option 1	<p>Floor = Compliance with the petroleum refinery NSPS.</p> <p>Option 1 = Compliance with provisions in 40 CFR part 60 subpart VV of the Petroleum Refinery NSPS, or complying with a modified negotiated regulation for equipment leaks presented in 40 CFR part 63 subpart H (HON equipment leaks).</p>
Miscellaneous Vents	MACT Floor	<p>Floor = Control of vents with VOC emissions greater than 72 lb/day (33 kg/day). For Group 1 vents only.</p>
Wastewater Streams	MACT Floor	<p>Floor = Compliance with the BWON, only for Group 1 streams.</p>
Storage Vessels	MACT Floor	<p>Floor = Group 1 storage vessels only are required to put on one of the following control systems: 1) an internal floating roof (IFR) with proper seals; 2) an external floating roof (EFR) with proper seals; 3) an EFR converted to an IFR with proper seals; or 4) a closed vent system with a 95 percent efficient control device.</p>

Also, if there was no regulation, the previous regulations would be relied upon as the basis for making judicial decisions regarding excess emissions.

#### 4.3.2 *State and Local Action*

The CAA requires the Agency to establish emission standards, and if EPA fails to do this, the burden falls on the States to develop and implement measures to attain and maintain such standards. Each State assembles these measures in a document called the State Implementation Plan (SIP). SIPs must be approved by EPA, and EPA is empowered to compel revision of plans it believes are inadequate. EPA may assume enforcement authority over air pollution control programs any State fails to implement. The standards will become parts of each State's SIP, and enforcement authority will be delegated to the States. If the EPA were not to promulgate the standards, States would be responsible for making case-by case MACT decisions under Section 112 (g) whenever there is a major modification, or when the date for MACT promulgation has passed without action on EPA's part.

EPA believes that reliance on State and local action is not a viable substitute for the standards. This belief holds even if EPA were to step up research and technology transfer programs to assist State and local governments.

#### 4.4 ROLE OF COST EFFECTIVENESS IN CHOOSING AMONG REGULATORY ALTERNATIVES

EPA has often used cost effectiveness (C/E) analysis as a guide for selecting among regulatory alternatives. Regulatory alternatives can sometimes be ranked based on stringency of control. All else equal, alternatives yielding the same level of control but higher average C/E (usually control cost per ton of pollutant reduced) could be eliminated from consideration. Incremental C/E can then be calculated for each step up the stringency ranking. The selection of a regulatory alternative could then be made by choosing the most stringent alternative below some agreed upon C/E cutoff. The level of such a C/E

cutoff would generally depend on the pollutant being controlled and other factors.

However, since the Petroleum Refinery NESHAP is to be a MACT standard, the role of C/E analysis for selecting a regulatory alternative for this regulation is somewhat limited. A MACT floor level of control stringency is required regardless of the C/E at this control level. At stringency levels beyond the MACT floor, cost effectiveness can be legally considered, and EPA believes cost-effectiveness of controls is a primary consideration for evaluating stringency levels beyond the MACT floor. The average cost effectiveness of the regulation (\$/Mg of pollutant removed) is included as part of the cost analysis in Chapter 5.

#### 4.5 ECONOMIC INCENTIVES: SUBSIDIES, FEES, AND MARKETABLE PERMITS

Economic incentive strategies, when designed properly, act to harness the marketplace to work for the environment. In deciding among regulatory options, EPA is required to consider as options such strategies which influence, rather than dictate, producer and consumer behavior, in order to achieve environmental goals. Economic incentive programs make environmental protection of economic interest to producers and consumers. When feasible, properly designed systems can be employed to achieve any environmental goal at the least cost to society.

Several types or categories of economic incentive strategies exist. One broad category of incentive programs is based on the use of fees or subsidies. Fee programs establish and collect a fee on emissions, providing a direct economic incentive for emitters to decrease emissions to the point where the cost of abating emissions equals the fee.<sup>3</sup> Similarly, subsidy programs provide a direct incentive for emitters to decrease emissions by providing subsidy payments for emission reductions beyond some baseline.

A second broad category of economic incentive strategies is based on the concept of emissions trading. A wide range of



variations in emissions trading programs are possible. The common idea in such programs is to allow sources with low abatement cost alternatives to trade or sell emission allowances to sources with higher abatement cost alternatives so that the cost of meeting a given total level of abatement is minimized.

There are two important constraints regarding the workability of economic incentive programs. The first constraint concerns the problem of emissions monitoring. Without an effective emissions monitoring system it is not possible to charge fees or use other economic incentive strategies. Only the traditional "command and control" approach of requiring employment of specific control technologies is feasible in this circumstance.

The second problem constraining the potential value of economic incentive strategies is legal. Various legal restrictions imposed by the CAA limit the applicability of economic incentive strategies to reduce air pollution.

Legal constraints imposed by Title III of the Act severely limit the usefulness of economic incentive strategies for reducing HAP emissions. Title III requires the implementation of MACT. Thus sources have little or no choice as to the type or level of control they implement except perhaps if going beyond the MACT floor control level. As a limited economic incentive, it may then be possible to impose, for example, an emissions fee on residual emissions after the MACT technology is employed to encourage additional control.

The applicability of economic incentive programs for the petroleum refinery NESHAP is therefore very limited. However, emissions averaging at the facility level may be feasible and legal given that each facility is considered an emissions source. This emissions averaging strategy allows facilities to trade emission reductions across emission points so as to minimize control costs for any given facility level emission reduction requirement. Thus, to this extent, an economic incentive strategy may be implemented for the Petroleum Refinery NESHAP regulation. The analysis of control costs (Chapter 5) does not incorporate emission averaging. It is recognized that if emissions averaging were incorporated into the standard,

facilities' costs of control should fall. Thus, the costs calculated could be an overestimate.

## REFERENCES

1. U.S. Environmental Protection Agency. Regulatory Impact Analysis for the National Emissions Standards for Hazardous Air Pollutants for Source Categories: Organic Hazardous Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry and Seven Other Processes. EPA-450/3-92-009. pp. 4-1 to 4-41. December 1992.
2. U.S. Environmental Protection Agency. Office of Air Quality Planning and Standards. Draft Preamble for the HON. December 1993.
3. U.S. Environmental Protection Agency. Office of Air Quality Planning and Standards. Draft Preamble for the Petroleum Refinery NESHAP. January 1994.
4. Reference 2.
5. U.S. Environmental Protection Agency. Office of Air Quality Planning and Standards. Municipal Waste Landfills - Regulatory Impact Analysis. March 1991.



## 5.0 COST ANALYSIS AND EMISSION REDUCTION

Section 5.1 of this chapter presents the methodology used to estimate the regulatory compliance costs for the option listed in Table 4-1. Section 5.2 presents total compliance costs by emission point, the corresponding emission reductions for each alternative, and discusses the cost effectiveness of controlling each of the four petroleum refinery emission points. Section 5.4 presents any cost categories not directly associated with a control technique, including monitoring, reporting, and recordkeeping costs.

### 5.1 APPROACH FOR ESTIMATING REGULATORY COMPLIANCE COSTS

This section explains the methods used for estimating the emissions associated with petroleum refineries and the impact associated with controlling existing petroleum refinery emission sources using various alternative control technologies. These estimates are used to compare different control alternatives and select the provisions for the proposed NESHAP for petroleum refineries.

Emissions and control impacts were estimated for each of the four petroleum refinery emission points: storage vessels, wastewater collection and treatment systems, equipment leaks, and miscellaneous process vents. The control impact estimates include estimates of emission reductions, control costs, and where applicable, energy impact. A qualitative assessment of the possible impact of secondary air pollution, water pollution, or solid waste generation is also included.

The emissions calculations involved three steps:

- (1) development of a database characterizing refineries,
- (2) development and assignment of scaling factors for each kind

of emission point to use for estimating emissions for refineries that provided no data, and (3) calculation of nationwide emissions and control impacts.

The database included the processes and technology used to produce refinery products and controls used to reduce emissions. This information came from responses to survey questionnaires sent out under section 114 of the CAA and information collection requests. Refineries across the United States responded to the questionnaires and provided control and process information for process vents, storage vessels, wastewater treatment systems, and leaking equipment. In addition, information on existing regulations was compiled to determine the control requirements that apply to petroleum refineries.

Because site-specific data were not available for every refinery, scaling factors relating refinery process parameters or emissions to the charge capacity of refinery processes were derived from the available data. Estimates of emissions and control impacts for refineries for which data were lacking were derived using scaling factors. Scaling factors could be used because the emission mechanisms and applicable control technologies are well understood for the kinds of sources to be regulated by the petroleum refinery NESHAP, and these characteristics are similar from refinery to refinery.

Baseline emissions represent emission levels from petroleum refineries that would occur in the absence of a refinery MACT standard. Baseline emissions were estimated using calculation algorithms based on known, previously published, well-established methods from the process charge capacities of the refineries in the database and the data reported in the questionnaire responses. The impact of each alternative control level was estimated using previously developed cost algorithms and control efficiencies for commonly used control technologies. The control technologies included in the analysis were chosen because they can achieve emission reductions at least as stringent as the MACT floor. While the selected control technologies were used as the basis of the control impacts estimates, the promulgated standards

are written using formats that would allow use of other control technologies if the equivalent emission reduction is achieved.

The impact estimates are based on average, representative, or typical emissions and control requirements for each kind of source. Thus, the estimates do not reflect the impact that would be observed at any particular refinery. However, they do provide a reasonable estimate of nationwide emission reductions and represent the range of control costs that refineries might incur under different regulatory alternatives.

The specific procedures used to estimate baseline emissions and the costs and emission reductions for the different control alternatives for each kind of emission point are described separately for new and existing sources.

#### 5.1.1 *Calculations for Existing Sources*

For existing petroleum refinery sources, baseline emissions and control impacts were calculated for the four sources for individual refineries and aggregated to determine nationwide impacts. Some sources were not as well characterized as others. In these cases, the available information was extrapolated to derive nationwide estimates.

5.1.1.1 *Storage Vessels.* Emissions and emission reductions from storage vessels are a function of the volatility of the material stored and the type of storage vessel. Responses to questionnaires sent to refineries provided information on the volatility and HAP content of materials stored and the types of vessels used to store materials. Based on information in the questionnaire responses, factors for storage vessel population and VOC emissions were developed and used to estimate baseline emissions of HAPs and VOC, emission reductions at the floor level of control and above, and costs for controlling emissions to the floor level of control and to levels more stringent than the floor. Thirteen "major" petroleum liquids were included in this analysis: crude oil, gasoline, naphtha, asphalt, alkylate, reformate, jet kerosene/kerosene, heavy gas oil, aviation gasoline, diesel/distillate, jet fuel (#4), residual fuel oil, and slop oil. In a previous analysis using all available

information, these 13 petroleum liquids accounted for more than 80 percent of the estimated nationwide baseline VOC emissions.

The storage vessel population factors were used to estimate the total number of vessels at each refinery. The storage vessels reported in the questionnaire responses were divided into groups based on storage vessel type (e.g., fixed roof), refinery crude capacity (greater than or less than 150,000 barrels per calendar day (bbls/cd)), and petroleum liquid stored (e.g., gasoline, naphtha, etc.). The average number of vessels in each group per barrel of crude capacity at a refinery was the tank population factor. For example, the questionnaire responses indicated that the number of internal floating roof vessels storing gasoline at refineries with crude capacities greater than 150,000 bbls/cd was  $1.2 \times 10^{-5}$  storage vessels per barrel of crude capacity per day. That is, a refinery of 267,000 barrels per day would have two internal floating roof tanks storing gasoline.

VOC emission factors were calculated for each storage vessel grouping. To calculate the VOC factor, VOC emissions from the storage vessels reported in the questionnaire responses were estimated using equations in chapter 12 of AP-42. Where data were missing or insufficient, default values, developed from information in the questionnaire responses, were used. Average VOC emission factors at the baseline level of control were then calculated for each vessel grouping. For example, for internal floating roof vessels storing gasoline at refineries with crude capacities greater than 150,000 bbls/cd, an average VOC emission factor of 15,000 lbs VOC emitted/vessel was calculated.

The number of vessels and the baseline VOC emissions nationwide were estimated in the following way. The crude capacity of each refinery in the nation, as listed in OGJ, was multiplied by the population factor for each applicable type of vessel to estimate the numbers and types of vessels at each refinery. This yielded the nationwide storage vessel population. The baseline VOC emission factor (lb VOC emitted/vessel) corresponding to each vessel type was multiplied by the number of vessels of that type to calculate the baseline VOC emissions at



each refinery. For example, for internal floating roof vessels storing gasoline at refineries with crude capacities greater than 150,000 bbls/cd the refinery crude capacity, times the tank population factor of  $1.2 \times 10^{-5}$  vessels per barrel, times the VOC emission factor of 15,000 lb VOC emitted/vessel yielded the estimated VOC emissions. Certain petroleum liquids (e.g., asphalt, alkylate, and reformate) are directly associated with specific process units. If OGJ did not list capacities for these specific process units, then the vessel population factor corresponding to that process unit was not applied to that refinery. (For more information, refer to "Summary of Nationwide Volatile Organic Compound and Hazardous Air Pollutant Emission Estimates from Petroleum Refineries," in the docket).

Emissions of HAPs were estimated by multiplying the VOC emissions calculated for each type of material stored by the average HAP weight fraction in the vapor phase of the material. Average vapor phase HAP weight fractions were calculated from the HAP liquid concentrations (obtained from industry questionnaire responses) using Raoult's Law and the vapor pressure of the individual HAPs.

Emission reductions and costs for control options were estimated using the extrapolated nationwide storage vessel population. For all control options, factors for average emission reduction and costs were developed by calculating specific emission reductions and costs for the 3,400 storage vessels reported in the questionnaire responses. Average emission reduction and cost factors were then calculated for each storage vessel group.

An analysis of refinery storage vessels indicated that the MACT floor level of control for existing sources is an internal floating roof with seals that comply with the NSPS for and with the hazardous organic NESHAP (HON) storage. Costs were estimated for equipping existing fixed roof storage vessels with an internal floating roof and seals that comply with specifications in the storage NSPS (40 CFR 60 subpart Kb) and HON (40 CFR 63 subpart G). For existing external and internal floating roof vessels, costs were estimated for installing seals that comply

with the proposed HON seal requirements. The MACT floor level of control for existing floating roof storage vessels does not include complying with the fitting requirements in the proposed HON.

More stringent controls were not identified for existing fixed roof storage vessels. For existing external and internal floating roof vessels, the more stringent control alternative is to comply with the fitting requirements in the proposed HON in addition to the seal requirements.

The emission reduction assigned to each of the 3,400 storage vessels was calculated as a function of the emission reductions presented in the EPA publication "NSPS VOC Emissions from VOL Storage Tanks--Background Information for Proposed Standards". This document provided the emission reduction (in percent) of various seal and fitting configurations compared with fixed roof vessels. For example, an internal floating roof vessel with a liquid mounted primary seal and controlled fittings has an average emission reduction of 96.2 percent over a similar sized fixed roof vessel. Adding a rim-mounted secondary seal increases this emission reduction to 96.6 percent. Therefore, the incremental emission reduction gained by adding the rim mounted secondary seal is 0.4 percent. The emission reduction applied to each storage vessel was calculated as the difference between the level of control required by the control option and the baseline level of control.

The cost equations for converting existing fixed roof vessels to internal floating roof vessels were taken from the "Control of Volatile Organic Compound Emissions from Volatile Organic Liquid Storage in Floating and Fixed Roof Tanks" (Draft, July 1992), and "Internal Instruction Manual for ESD Regulation-Storage Tanks" (January 1993). The cost equations for adding seals and controlled fittings to existing external and internal floating roof vessels were also taken from these two documents.

#### 5.1.1.2 *Wastewater Collection and Treatment Systems.*

Emissions and emission reductions from wastewater collection and treatment systems are both a function of wastewater stream flow, the HAP compound concentration in the wastewater, and the

volatility of the HAP compounds in the wastewater. Emission reductions are also a function of the design and operating parameters of the control device.

EPA gathered data for the wastewater stream flow rate and the concentration of HAPs in petroleum refinery wastewater to develop models of wastewater from process units found at refineries. Each model process unit was assigned representative values for the concentration and volatility of the HAPs in its wastewater stream. A ratio of wastewater stream flow to refinery crude capacity was also developed for each model process unit and applied to the capacities reported in OGJ for each process unit at each refinery. (For more information, refer to "Data Summary for Petroleum Refinery Wastewater," in the docket). Mass loadings of volatile HAP in wastewater were determined by multiplying volatile HAP concentrations by capacity-based wastewater stream flow rates for each process unit at each refinery in the nation. The results of prior EPA analyses developed for the HON were judged to be appropriate to use to estimate the cumulative mass fraction of HAPs emitted from wastewater collection and treatment systems.

Uncontrolled emissions were determined by multiplying the mass fraction of HAPs emitted by the mass loading of volatile HAPs. However, many petroleum refineries control their wastewater collection and treatment systems in accordance with the BWON. (For more information, refer to "The Effectiveness of the BWON in Controlling Volatile HAP Mass Loading in Petroleum Refinery Wastewater," in the docket). These controls were credited in the national baseline emissions calculations by applying the applicability criteria of the BWON (i.e., wastewater streams with flows greater than 0.02 l/min and benzene concentration of 10 ppmw or greater at a facility with at least 10 Mg/yr total annual benzene loading in wastes and wastewater) to each refinery and wastewater stream and by assuming that the control requirements of the BWON (i.e., 99 percent reduction of benzene) were met for those streams requiring control.

An analysis of existing refinery wastewater collection and treatment systems indicated that the MACT floor for wastewater is the BWON. (For more information, refer to ["Maximum Achievable Control Technology Floor for Process Wastewater Streams at Petroleum Refineries,"] in the docket). Existing refineries are already required to comply with the BWON, so no emission reductions or costs would be associated with the floor option for refinery wastewater sources. In considering a control option more stringent than the BWON, the EPA assessed the effects of lowering the applicability threshold of the BWON, by eliminating the cutoff of 10 Mg/yr TAB loading in facility wastes and wastewater. The additional wastewater streams requiring control (those streams with at least 10 ppmw benzene at refineries with a TAB under the 10 Mg/yr loading criterion) were assumed to be steam stripped to achieve reductions equivalent to the requirements of the BWON (e.g., 99 percent reduction of benzene). The overheads from the steam stripper were assumed to be sent to a combustion device. (For more information, refer to ["Control Option Above the Floor for Petroleum Refinery Process Wastewater,"] in the docket). The results of prior EPA analyses were used to estimate the mass fraction of HAPs removed from a wastewater stream by a steam stripper as well as the costs associated with the stripper system. (For more information, refer to "Steam Stripper Removals and Costing for Petroleum Refinery Wastewater," in the docket). The results of those analyses indicate that the selected steam stripper design and operating parameters achieve a 95 to 99 percent removal, depending on the volatility of the HAPs in the stream.

5.1.1.3 *Equipment Leaks*. Emissions and emission reductions from leaking equipment are a function of the component counts and the control program used to reduce emissions. The questionnaires were designed to obtain equipment leak information for 18 different refinery process units because the controls required may vary from process unit to process unit. The questionnaire responses included information on component counts, the HAP content of refinery process streams, and the monitoring frequencies and leak definitions used for leak detection and

repair programs for each refinery process unit. The monitoring frequencies and leak definitions reported for each process unit were matched to the requirements of existing LDAR programs to determine which control program was being used to reduce emissions.

Data on equipment leaks were reported by approximately 70 percent of the refineries in the nation. For those refineries not reporting information, the characteristics of model process units (for each of the 18 process units of interest) were assigned to the refinery based on information in OGJ. The model process units were developed as the median component count of the process units from refineries reporting information in the surveys. If OGJ data indicated that a refinery contained a specific process unit, then the median counts for the model representing that process unit was assigned to the refinery. If the refinery was determined to be in an ozone nonattainment area, the EPA assumed that the refinery would be controlled to the level of control in the petroleum refinery CTG.

Uncontrolled HAP emissions from each of the 18 different refinery process units were estimated by multiplying the uncontrolled VOC emissions from each unit by the average HAP-to-VOC ratio of the streams associated with each unit. Uncontrolled VOC emissions from leaking equipment were estimated on a process unit basis by multiplying the component counts for the process unit by VOC emission factors for each equipment component. The VOC emission factors relate VOC emissions to the type of component leaking (e.g., pumps, valves, etc.) in units of lb/hr/component type. The emission factors used for the impacts analysis were taken from a previous EPA study on leaking refinery equipment and presented in chapter 9 of AP-42. These emission factors are currently being reviewed by EPA based on new industry data. The emission estimates may be revised at promulgation if new factors are developed by EPA based on the new industry data.

Baseline emissions of HAPs and VOC were estimated by multiplying the uncontrolled emissions by one minus the control efficiencies associated with each LDAR program reported by or assigned to each refinery. The "Equipment Leaks Enabling

Document" (in the docket) provides information on the control efficiencies that may be achieved by monitoring components under various LDAR programs. (For more information, refer to "Summary of Nationwide Volatile Organic Compound and Hazardous Air Pollutant Emission Estimates from Petroleum Refineries," in the docket).

An analysis of existing controls on refinery equipment leaks indicated that the MACT floor level of control for refinery equipment leaks was the control required by the Petroleum Refinery NSPS. For more information refer to ["Maximum Achievable Control Technology Floor for Equipment Leaks at Petroleum Refineries," in the docket]. Two more stringent control options were also analyzed: (1) compliance with the negotiated equipment leaks regulation included in the HON, without the monitoring requirements for connectors, and (2) compliance with the negotiated equipment leaks regulation included in the HON. Each of these options requires specific leak monitoring frequencies for components and control devices. Emission reductions for controlling leaking equipment to the level of control required by the NSPS and the two more stringent options were calculated from the difference between baseline emissions and the emissions calculated using the percent reductions associated with the petroleum refinery NSPS and the HON equipment leaks negotiated rule. Similarly, the cost impact of controlling leaking equipment to the level required by the NSPS and the two more stringent control options was calculated from the cost of control devices and labor associated with the petroleum refinery NSPS and the negotiated rule. The cost methodology was based on procedures provided in the "Equipment Leaks Enabling Document." (For more information, refer to ["Costs for the MACT Floor Level of Control and Control Options Above the Floor for Controlling Emissions from Leaking Refinery Equipment,"] in the docket).

5.1.1.4 *Miscellaneous Process Vents.* The miscellaneous process vent group includes most miscellaneous process vents that emit organic HAPs at refineries other than FCCU catalyst regeneration vents, catalyst reformer catalyst regeneration

vents, and sulfur plant vents. The baseline HAP emissions from miscellaneous process vents were estimated by multiplying HAP emission factors by the charge capacities of refinery processes. Specific HAP emission factors were developed by dividing the HAP emissions reported in questionnaire responses by the charge capacities of those refineries reporting the specific HAP. (For further information, refer to "Summary of Nationwide Volatile Organic Compound and Hazardous Air Pollutant Emission Estimates from Petroleum Refineries," in the docket).

The MACT floor level of control for these vents was combustion. EPA has determined that combustion of emissions can achieve 98 percent organic HAP reduction, so emission reductions were calculated by applying this percent reduction to emissions from miscellaneous process vents that are uncontrolled at baseline. The cost for controlling emissions from miscellaneous vents includes the cost for piping emissions to existing control devices and an additional compressor for the refinery. EPA assumed that refineries would already have an existing fuel gas or flare system that could be used to reduce emissions from miscellaneous process vents. Further information on costing procedures and specific assumptions is contained in "Costing Methodology for Controlling Emissions for Miscellaneous Process Vents," in the docket.

#### 5.1.2 *Calculations for New Sources*

This section explains the methodology used for estimating emissions and control impacts in the first 5 years after the promulgation of this rule. These costs represent control of new process units and equipment built within the first 5 years after promulgation. It should be noted for regulatory purposes, that some of these units and equipment will be considered "new sources" and others will be considered part of an "existing source". It is not possible to determine how many new units will fall into each of these categories; however, controls will be required for the emission points in either case.

Costs for controlling new process units were estimated from the costs calculated for existing sources and the number of new process units that are expected to be constructed in the 5-year

period after the standard is enacted. The costs for applying control technologies to existing sources were calculated as previously described. The results are documented in the four memoranda presenting cost impacts (in the docket). The cost information was scaled up to account for new emission points that may need to be controlled in the first 5 years after the petroleum refinery NESHAP has been promulgated. Reductions of emissions of HAPs and VOC from controlling existing emission points were also presented in the costing memorandum. The emission reduction information was scaled up to account for controls on new emission points using the same methodology that was used to scale up cost data. (For further information, refer to "Estimation of Annual Costs for New Petroleum Refinery Emission Points in the Fifth Year After Promulgation," in the docket).

OGJ provided estimates of annual refinery construction projects. This information was used to determine an average number of process units constructed in a year.

5.1.2.1 *Storage Vessels.* The MACT floor for storage vessels at new sources is application of seals and fittings equivalent to those required by 40 CFR 60 subpart Kb (the NSPS for VOL storage) to storage vessels larger than 151 m<sup>3</sup> (947 bbl) with vapor pressures above 3.5 kPa (0.50 psia). (These seals and fittings are the same as those required by the HON.) The petroleum refinery NESHAP would result in no costs or emission reductions for those storage vessels required to comply with subpart Kb (all new vessels with a capacity greater than or equal to 40 m<sup>3</sup> or 250 bbl). This methodology may overestimate the impact of the regulation in the 5 years after promulgation because, as previously stated, many vessels constructed in that period may be considered part of existing sources for regulatory purposes. Because the requirements for existing sources are equivalent to the NSPS, there will be no costs or emission reductions for existing storage vessels. Therefore, the fifth year impacts on vessels at new sources would be lower than the impact estimated here because the number of vessels at new sources is probably overestimated.



5.1.2.2 *Wastewater Collection and Treatment Systems.* A MACT floor analysis performed on wastewater collection and treatment systems indicated that the MACT floor level of control for wastewater streams at new sources is compliance with the BWON. Therefore, no costs are anticipated for sources built in the 5 years after promulgation to reach the MACT floor level of control. The control option more stringent than the floor that was considered was the same as the option considered for existing sources: assessing the effects of lowering the applicability threshold of the BWON by eliminating the cutoff of 10 Mg/yr TAB loading in facility wastes and wastewater.

The average annual number of newly constructed process units that will generate wastewater is expected to be approximately 34. The distribution of these new units across refinery processes was based on OGJ data. (For more information, refer to the docket). Using the same approach for applying controls and estimating costs for new sources as for existing sources, costs for the newly constructed units were estimated. The total estimated capital investment for controls by the fifth year (considering 34 new units per year over the 5-year period) would be approximately \$42 million. The total annual cost to be expended in the fifth year (considering all 170 new units) would be approximately \$18 million per year.

5.1.2.3 *Equipment Leaks.* OGJ provides annual construction projects in petroleum refineries and expected dates of completion. This information, for a 5-year period from 1988 to 1992, was used to develop an average count of new construction projects 5 years after promulgation of the refinery NESHAP. From this information, it was determined that an average of 34 process units would be built annually. Each of these process units is expected to require control under the NSPS for refineries. Therefore, the only cost associated with controlling these units is the extra cost required to go from the NSPS control requirements (the MACT floor for equipment leaks at new sources) to the two options more stringent than floor. The two options are the same as for existing sources: (1) the negotiated regulation for equipment leaks in the HON (40 CFR 63 subpart H)

without the monitoring requirements for connectors and (2) the HON negotiated regulation.

The average capital investment cost and annual cost of upgrading from the NSPS to the HON negotiated regulation without connector monitoring were determined to be \$20,000 and \$7,000/yr per process unit, respectively. The average capital investment and annual cost of upgrading from the NSPS to the HON negotiated regulation were determined to be \$17,000 and \$6,200/yr per process unit, respectively. For each option, the capital investment cost and average annual cost for controlling the 34 process units constructed each year was calculated by multiplying the average cost per process unit by the number of new process units.

5.1.2.4 *Miscellaneous Process Vents.* The MACT floor level of control for miscellaneous process vents at new sources was determined to be combustion. The annual cost for controlling emissions from miscellaneous vents consisted the cost for piping to an existing combustion system (to a flare or to the fuel gas system) and for an additional compressor for each refinery. The average capital cost for piping for each vent and a compressor for each refinery was determined to be \$9,910 and \$66,100, respectively, and the average annual cost of piping for each vent and compressor for each refinery was determined to be \$2,170 and \$37,800, respectively.

As previously stated, the average annual number of newly constructed process units is expected to be 34. The number of miscellaneous vents requiring control was calculated from the average number of uncontrolled vents per process unit, as presented in the baseline emissions estimation memorandum (refer to docket). Based on this information, one vent for each of the 34 process units is estimated to require control (that is, a total of 34 new vents will require control each year). This number of vents per year was multiplied by the average cost per vent to estimate national costs for miscellaneous process vents for process units constructed in the 5 years after promulgation of this rule.

## 5.2 TOTAL COMPLIANCE COST ESTIMATES, REDUCTIONS, AND COST EFFECTIVENESS

The annualized compliance costs by emission point are shown in Table 5-1 for the chosen alternative. The total national cost of Alternative 1 in the fifth year is \$79 million. Table 5-2 presents the costs, HAP emission reductions, and cost effectiveness for the control options by emission point. The average cost effectiveness of the regulation (\$/Mg of pollutant removed) is determined by dividing the annual cost by the annual emission reduction. Table 5-3 presents a summary of the HAP emission reductions, total cost, and cost effectiveness values for the chosen regulatory alternatives. The emission reductions associated with the alternatives in Table 5-3 were calculated by summing the HAP emission reductions listed in Table 5-2 for the control option chosen at each emission point. The annual costs are as reported in Table 5-1, and the cost effectiveness values were calculated as described above. The incremental cost effectiveness represents the increase in cost from Alternative 1 to Alternative 2 divided by the increased HAP emission reduction. Table 5-4 reports similar information for VOC emissions.

TABLE 5-1. SUMMARY OF TOTAL ANNUAL COSTS IN THE FIFTH YEAR FOR THE PETROLEUM REFINING NESHAP

Emission Point	Option	Annual Fifth Year Costs (1000\$/yr) <sup>3</sup> (1992 Dollars)		
		Existing Sources	New Construction	Total Alternative 1
Equipment Leaks	Floor	\$69,000	\$ 0	\$69,000
	Option 1 <sup>1</sup>	\$59,000	\$(210)	\$58,790
Miscellaneous Process Vents	Floor <sup>2</sup>	\$12,000	\$370	\$12,370
	Floor <sup>1</sup>	\$ 0	\$ 0	\$ 0
Wastewater Systems	Floor <sup>1</sup>	\$8,000	\$98	\$8,098
Storage Vessels				
Other Recordkeeping and Reporting				\$1,000
<b>TOTAL COST</b>				<b>\$79,190</b>

NOTES: <sup>1</sup>Alternative 1.

<sup>2</sup>EPA did not choose an option above the MACT floor for miscellaneous process vents.

<sup>3</sup>Costs are in 1992 dollars.

TABLE 5-2. CONTROL OPTIONS AND IMPACTS BY EMISSION POINT

Emission Point	HAP					Average	Incrementa 1
	Baseline HAP Emissions (Mg/yr)	Control Option	Emission Reduction (Mg/yr)	Percent Emission Reduction	Annual Cost (\$1,000/yr) <sup>b</sup>		
Miscellaneous Process Vents Existing Sources	8,900	Floor*	7,600	85	\$11,000	\$1,500	N/A
New Sources <sup>a</sup> Storage Vessels Existing Sources	900	Floor*	770	85	\$370	\$480	N/A
	9,000	Floor*	670	7	\$3,700	\$5,500	N/A
		Option 1	1,300	14	\$6,200	\$4,800	\$4,000
		Option 2	1,800	20	\$8,400	\$4,700	\$4,400
		Option 3	2,600	29	\$32,000	\$12,000	\$30,000
	290	Floor*	4	1.4	\$98	\$24,000	N/A
		Option 1	14	4.8	\$550	\$39,000	\$45,000
Wastewater Systems Existing Sources	9,200	Floor*	0	N/A	0	N/A	N/A
		Option 1	7,700	93	\$120,000	\$15,000	\$15,000
	960	Floor*	0	N/A	0	N/A	N/A
		Option 1	930	97	\$18,000	\$20,000	\$20,000
Equipment Leaks Existing Sources	50,000	Floor	35,000	69	\$69,000	\$2,000	N/A
		Option 1*	44,000	87	\$58,000	\$1,500	\$(330)
		Option 2	46,000	91	\$78,000	\$1,700	\$6,000
	1,300	Floor	0	0	0	0	0
		Option 1*	640	49	\$(210)	\$(330)	\$(330)
		Option 2	760	59	\$840	\$1,100	\$8,300

**NOTES:**

<sup>a</sup>Impacts were estimated for new process units constructed in the 5 years after promulgation. For regulatory purposes, some of these units may be considered new sources while others may be considered part of an existing source.

<sup>b</sup>The costs for monitoring, recordkeeping, and reporting (MRR) requirements are not available on an emission point basis. The costs in this table reflect costs for operation and maintenance of control equipment only.

N/A = Not applicable.

Brackets indicate negative values.

\* = Control option chosen for preferred alternative.

TABLE 5-3. COST, HAP EMISSION REDUCTION, AND COST EFFECTIVENESS BY ALTERNATIVE

Regulatory Alternative	HAP Emissions (Mg/Yr)	Annual Cost (Million \$, 1992) <sup>1</sup>	Cost Effectiveness (\$/Mg)	
	Reduction		Average	Incremental
Alternative 1	48,000	\$79.0	\$1,645	N/A

NOTES: N/A = Not applicable.

<sup>1</sup>Cost estimates do include costs associated with monitoring, recordkeeping, and reporting requirements.

TABLE 5-4. COST, VOC EMISSION REDUCTION, AND COST EFFECTIVENESS BY ALTERNATIVE

Regulatory Alternative	VOC Emission Reduction (Mg/Yr) <sup>1</sup>	Annual Cost (Million \$, 1992)	Cost Effectiveness (\$/Mg)	
			Average	Incremental
Alternative 1	252,000	\$79.0	\$313	N/A

NOTES: N/A = Not applicable.

<sup>1</sup>Emission reduction estimates do not incorporate reductions occurring at new sources.

### 5.3 MONITORING, RECORDKEEPING, AND REPORTING COSTS

In addition to provisions for the installation of control equipment, the promulgated regulation includes provisions for MRR. EPA estimates that the total annual cost for refineries to comply with the MRR requirements is \$20 million. After incorporating MRR costs, the total cost of compliance of Alternative 1 is \$79 million. For Alternative 1, the incorporation of MRR costs into total annual cost results in an average cost effectiveness of \$313 for each megagram of VOC reduced and \$1,645 for each megagram of HAP reduced.

In order to calculate the costs of MRR associated with the petroleum refinery NESHAP, estimates of hours per item (i.e., a required MRR action), frequency of required action per year, and number of respondents (i.e., total number of individuals required to submit compliance reports) were estimated based on the requirements in the proposed rule for all of the emission points. To compute the costs associated with the burden estimates, a wage rate of \$34 per hour (in 1992 dollars) was assumed. This assumption was based on an estimate that 85 percent of the labor will be accomplished by technical personnel (typically by an engineer with a wage rate of \$33 per hour), 10 percent will be completed by a manager (at \$49 per hour), and 5 percent by clerical personnel (at \$15 per hour). All of the wage rates include an additional 110 percent for overhead. Costs were annualized assuming an expected remaining life for affected facilities of 15 years from the date of promulgation of the subject NESHAP, and using an interest rate of 7 percent.

Compliance requirements vary in terms of frequency. This variance is taken into account in the annualization of costs. Performance tests to demonstrate compliance with the control device requirements are required once. Compliance requirements also include monitoring of operating parameters of control devices and records of work practice and other inspections. These activities must be reported semiannually. The compliance requirements that must be met only once are annualized over the time from the year in which they are to take place to the expected end of facility life.



The MRR requirements are outlined separately in the regulation for each emission point. The compliance determination provisions for storage vessels include inspections of vessels and roof seals. If a closed vent system and control device is used for venting emissions from storage vessels, the owner must establish appropriate monitoring procedures. For wastewater stream and treatment operations, the MRR requirements are outlined in the rule for the BWON.

For miscellaneous process vents, the promulgated standard specifies the performance tests, monitoring requirements, and test methods necessary to determine whether a miscellaneous process vent stream is required to apply control devices and to demonstrate that the allowed emission levels are achieved when controls are applied. The format of these requirements, as with the format of the miscellaneous process vent provisions, depends on the control device selected. The MRR requirements for miscellaneous process vents are summarized by control device in Table 5-5.

For equipment leaks, because the provisions of the proposed rule are work practice and equipment standards, monitoring, repairing leaks, and maintaining the required records constitutes compliance with the rule. The HON equipment leak provisions are appropriate to determine continuous compliance with the petroleum refinery equipment leak standards. In summary, these provisions require periodic monitoring with a portable hydrocarbon detector to determine if equipment is leaking.

TABLE 5-5. MISCELLANEOUS PROCESS VENTS — MONITORING, RECORDKEEPING, AND REPORTING REQUIREMENTS FOR COMPLYING WITH 98 WEIGHT-PERCENT REDUCTION OF TOTAL ORGANIC HAP EMISSIONS OR A LIMIT OF 20 PARTS PER MILLION BY VOLUME

Control Device	Parameters to be Monitored <sup>a</sup>	Recordkeeping and Reporting Requirements for Monitored Parameters
Thermal Incinerator	Firebox temperature <sup>b</sup> [63.644 (a) (1) (i)]	<ol style="list-style-type: none"> <li>1. Continuous records<sup>c</sup></li> <li>2. Record and report the firebox temperature averaged over the full period of the performance test - NCS<sup>d</sup></li> <li>3. Record the daily average firebox temperature for each operating day<sup>e</sup></li> <li>4. Report all daily average temperatures that are outside the range established in the NCS or operating permit and all operating days when insufficient monitoring data are collected<sup>f</sup> - PR<sup>9</sup></li> </ol>
Catalytic Incinerator	Temperature upstream and downstream of the catalyst bed [63.644 (a) (1) (ii)]	<ol style="list-style-type: none"> <li>1. Continuous records</li> <li>2. Record and report the upstream and downstream temperatures and the temperature difference across the catalyst bed averaged over the full period of the performance test - NCS</li> <li>3. Record the daily average upstream temperature and temperature difference across catalyst bed for each operating day<sup>e</sup></li> <li>4. Report all daily average upstream temperatures that are outside the range established in the NCS or operating permit - PR</li> </ol>

TABLE 5-5 (continued).

Control Device	Parameters to be Monitored <sup>a</sup>	Recordkeeping and Reporting Requirements for Monitored Parameters
Boiler or Process Heater with a design heat input capacity less than 44 megawatts and Vent Stream is <u>not</u> introduced with or as the primary fuel <sup>h,i</sup>	Firebox temperature <sup>b</sup> [63.644(a)(4)]	<p>5. Report all daily average temperature differences across the catalyst bed that are outside the range established in the NCS or operating permit - PR</p> <p>6. Report all operating days when insufficient monitoring data are collected<sup>f</sup></p> <p>1. Continuous records</p> <p>2. Record and report the firebox temperature averaged over the full period of the performance test - NCS</p> <p>3. Record the daily average firebox temperature for each operating day<sup>e</sup></p> <p>4. Report all daily average firebox temperatures that are outside the range established in the NCS or operating permit and all operating days when insufficient monitoring data are collected<sup>f</sup> - PR</p>

TABLE 5-5 (continued).

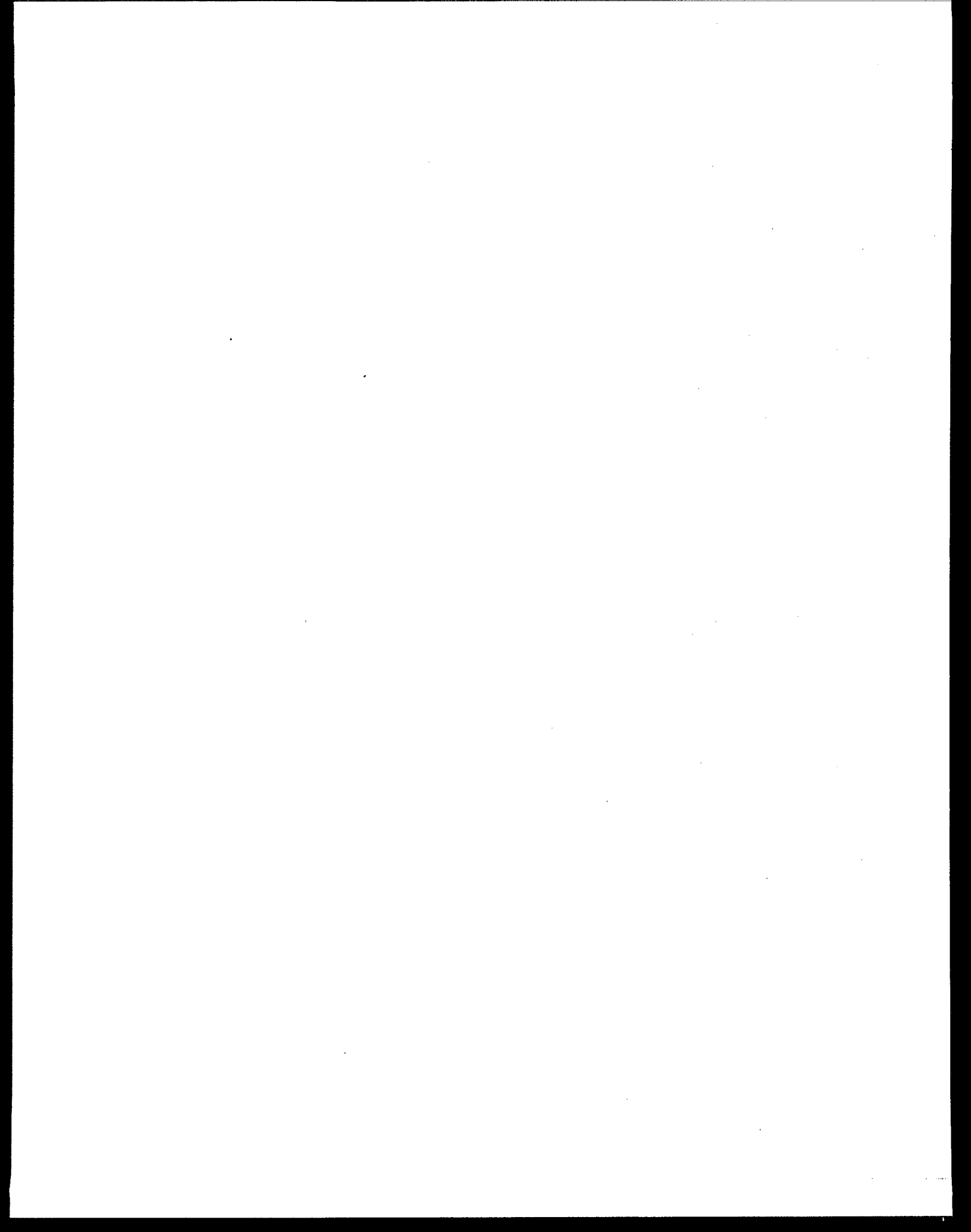
Control Device	Parameters to be Monitored <sup>a</sup>	Recordkeeping and Reporting Requirements for Monitored Parameters
Flare	Presence of a flame at the pilot light [63.644 (a) (2)]	<ol style="list-style-type: none"> <li data-bbox="516 245 634 1156">1. Hourly records of whether the monitor was continuously operating and whether the pilot flame was continuously present during each hour</li> <li data-bbox="667 245 756 1156">2. Record and report the presence of a flame at the pilot light over the full period of the compliance determination - NCS</li> <li data-bbox="789 245 878 1156">3. Record the times and durations of all periods when a pilot flame is absent or the monitor is not operating</li> <li data-bbox="911 245 997 1156">4. Report the times and durations of all periods when all pilot flames of a flare are absent - PR</li> </ol>

TABLE 5-5 (continued).

Control Device	Parameters to be Monitored <sup>a</sup>	Recordkeeping and Reporting Requirements for Monitored Parameters
All Control Devices	Presence of flow diverted to the atmosphere from the control device [63.644(c)(1)] or [63.644(c)(2)]	<ol style="list-style-type: none"> <li>1. Hourly records of whether the flow indicator was operating and whether flow was detected at any time during each hour.</li> <li>2. Record and report the times and durations of all periods when the vent stream is diverted through a bypass line or the monitor is not operating - PR</li> </ol>
	Monthly inspections of sealed valves [63.644(c)(2)]	<ol style="list-style-type: none"> <li>1. Records that monthly inspections were performed</li> <li>2. Record and report all monthly inspections that show the valves are not closed or the seal has been changed - PR</li> </ol>

NOTES:

- <sup>a</sup>Regulatory citations are listed in brackets.
- <sup>b</sup>Monitor may be installed in the firebox or in the ductwork immediately downstream of the firebox before any substantial heat exchange is encountered.
- <sup>c</sup>"Continuous records" is defined in §63.641 of this subpart.
- <sup>d</sup>NCS = Notification of Compliance Status described in §63.652(e) of this subpart.
- <sup>e</sup>The daily average is the average of all recorded parameter values for the operating day. If all recorded values during an operating day are within the range established in the NCS or operating permit, a statement to this effect can be recorded instead of the daily average.
- <sup>f</sup>When a period of excess emission is caused by insufficient monitoring data, as described in §63.552(f)(3)(i)(C) of this subpart, the duration of the period when monitoring data were not collected shall be included in the Periodic Report.
- <sup>g</sup>PR = Periodic Reports described in §63.652(f) of this subpart.
- <sup>h</sup>No monitoring is required for boilers and process heaters with heat input capacities  $\geq 44$  megawatts or for boilers and process heaters where the vent stream is introduced with or as the primary fuel. No recordkeeping or reporting associated with monitoring is required for such boilers and process heaters.
- <sup>i</sup>Process vents that are routed to refinery fuel gas systems are not regulated under this subpart. No monitoring, recordkeeping, or reporting is required for boilers and process heaters that combust refinery fuel gas.



## 6.0 ECONOMIC IMPACTS AND SOCIAL COSTS

The goal of the RIA is to evaluate the potential benefits and costs of specific pollution control standards on our nation's economy. Potential regulatory benefits relate to reduced HAP and VOC emissions that have detrimental effects on the health and well-being of members of society. Social costs associated with the regulation are those costs borne by consumers and producers of refined petroleum products and by society at large as a result of the proposed standards. A comparison of the costs and benefits or net benefits (social benefits less social costs) of alternative control measures serves as one valuable criterion for rational and effective environmental policymaking.

The emission control measures considered in this analysis will require domestic petroleum refineries to incur increased investment costs for control equipment and the associated annual operation and maintenance expenses. Increased costs of production may impact the domestic petroleum refining market in a number of ways. This report will examine primary market impacts resulting from the control measures including changes in the market equilibrium price for refined petroleum products, output levels for products produced and sold nationally, value of domestic shipments or revenues for refineries in the industry, and plant operations. Predicted changes in the market equilibrium price and quantity of refined petroleum products produced and sold will result in additional market modifications or secondary market impacts. The secondary effects relate to the likely labor market adjustments (employment effects), energy input market changes (changes in the energy used as an input in the production of petroleum products) and foreign trade effects (change in net exports). Control measures may also influence the capital

availability and financial position of firms in the petroleum refining industry. Welfare changes for consumers, producers, and society at large or the social costs of the proposed emission controls will also be evaluated. Additionally, the Regulatory Flexibility Act (RFA) requires that an assessment be made of the effect of control measures on small entities.

This chapter will briefly describe the methods used to estimate the primary impacts, secondary effects, and small business impacts of the emission controls on the petroleum refining industry. A more detailed description of the methods used in the analysis is available in the *Economic Impact Analysis of the Petroleum Refinery NESHAP* (1995). A profile of the petroleum refining industry, the primary market impacts, capital availability consequences, secondary market impacts, small business impacts, and social costs of the control measures will be presented in this chapter.

## 6.1 PROFILE OF THE PETROLEUM REFINING INDUSTRY

The petroleum industry can be divided into five distinct sectors: (1) exploration, (2) production, (3) refining, (4) transportation, and (5) marketing. *Refining*, the process subject to this NESHAP, is the process which converts crude oil into useful fuels and other products for consumers and industrial users. The Standard Industrial Classification (SIC) code for all petroleum refineries is 2911. Although petroleum refineries produce a diverse slate of products, the five primary output categories are (1) motor gasoline, (2) jet fuel, (3) residual fuel, (4) distillate fuel, and (5) liquefied petroleum gases (LPGs), which in total accounted for 93 percent of all domestically refined petroleum products in 1992. This analysis is concerned only with these five main product categories.

It should be noted that the economic impact analysis reflects the compliance costs from the proposal. Thus the actual impacts are smaller than estimated here, though only by a minor amount.



A brief overview of the petroleum refining industry is presented in this section. Economic and financial data which characterize conditions in the refining industry and that are likely to influence the economic impacts associated with the implementation of the alternative NESHAPs are discussed. The information in this section represents the data inputs to the economic model used in the EIA. More details concerning the industry are provided in the *Economic Impact Analysis of the Petroleum Refinery NESHAP* (1995) and *Industry Profile of the Petroleum Refinery NESHAP* (1993).

#### 6.1.1 Profile of Affected Facilities

A brief description of the facilities affected by the proposed emission controls is presented in this section. The processes and product market characteristics of the petroleum refining industry are discussed. Refineries subject to the regulations are identified by geographical location, capacity, and complexity.

6.1.1.1 *General Process Description.* The refining process transforms crude oil into a wide range of petroleum products which have a variety of applications. The refining industry has developed a complex variety of production processes used to transform crude oil into its various final forms, many of which are already subject to some CAA controls.

There are numerous refinery processes from which HAP emissions occur. *Separation processes* (such as atmospheric distillation and vacuum distillation), *breakdown processes* (thermal cracking, coking, visbreaking), *change processes* (catalytic reforming, isomerization), and *buildup processes* (alkylation and polymerization) all have the potential to emit HAPs. HAP emissions may occur through process vents, equipment leaks, or from evaporation from storage tanks or wastewater streams. The NESHAP will address emissions from all of these refinery emission points.

6.1.1.2 *Product Description and Differentiation.* Most petroleum refinery output consists of motor gasoline and other types of fuel, but some non-fuel uses exist, such as

petrochemical feedstocks, waxes, and lubricants. The output of each refinery is a function of its crude oil feedstock and its preferred petroleum product slate.

Motor gasoline is defined as a complex mixture of relatively volatile hydrocarbons that has been blended to form a fuel suitable for use in spark-ignition engines. Residual fuel oil is a heavy oil which remains after the distillate fuel oils and lighter hydrocarbons are distilled away in refinery operations. Uses include fuel for steam-powered ships, commercial and industrial heating, and electricity generation. Distillate fuel oil is a general classification for one of the petroleum fractions produced in conventional distillation operations. It is used primarily for space heating, on- and off-highway diesel engine fuel (including railroad engine fuel and fuel for agricultural machinery), and electric power generation. Jet fuel is a low freezing point distillate of the kerosene type used primarily for turbojet and turboprop aircraft engines. LPGs are defined as ethane, propane, butane, and isobutane produced at refineries.

Product differentiation is a form of non-price competition used by firms to target or protect a specific market. The extent to which product differentiation is effective depends on the nature of the product. The more homogenous the overall industry output, the less effective differentiation by individual firms becomes. Each of the five petroleum products in this analysis are by nature quite homogenous — there is little difference between one company's premium gasoline and another's — and, as a result, differentiation does not play a major role in the competitiveness among petroleum refineries.

6.1.1.3 *Distinct Market Characteristics.* The markets for refined petroleum products vary by geographic location. Regional markets may differ due to the quality of crude supplied or the local product demand. Some smaller refineries which produce only one product have single, local markets, while larger, more complex refineries have extensive distribution systems and sell their output in several different regional markets. In addition, because refineries are the source of non-hydrocarbon pollutants

such as individual HAPs, volatile organic compounds (VOCs), sulfur dioxide (SO<sub>2</sub>), and nitrogen oxide (NO<sub>x</sub>), many Federal, State, and local regulations are already in place in some locations. Differences in the regional market structure may also result in different import/export characteristics.

The United States is segmented into five regions, called Petroleum Administration for Defense Districts (PADDs), for which statistics are maintained. PADDs were initiated in the 1940s for the purpose of dividing the United States into five economically and geographically distinct regions. Relatively independent markets for petroleum products exist in each PADD.

In addition to differences in regional markets, each of the five product categories in this analysis possesses its own individual market segment, satisfying demand among different end-use sectors. The substitutability of one of the products — motor gasoline, for example — is not possible with another refinery output, such as jet fuel. Thus, each of the products in this analysis is treated as a separate product with its own share of the market. From a refinery standpoint, however, if the production of one refined product were to become less costly after regulation, production of this product may increase at the expense of a product with a more costly refining process.

6.1.1.4 *Affected Refineries and Employment.* There were 192 operable petroleum refineries in the United States as of January 1, 1992.<sup>1</sup> Though refineries differ in capacity and complexity, almost all refineries have some atmospheric distillation capacity and additional downstream charge capacity. Most of the employment in the industry exists at larger refineries. Slightly fewer than 4 percent of refinery employees work in establishments of fewer than 100 people, and the remaining 96 percent of the labor force in the industry works at establishments of 100 employees or more.

6.1.1.5 *Capacity and Capacity Utilization.* Refineries have many different specialties, targeted product slates, and capabilities. Some refineries produce output only by processing crude oil through basic atmospheric distillation. These refineries have very little ability to alter their product yields

and are deemed to have low complexity. In contrast, refineries that have assorted downstream processing units can substantially improve their control over yields, and thus have a higher level of complexity. Because of their differences in size and complexity, refineries can be grouped by two main structural features: (1) atmospheric distillation capacity (which denotes their size) and (2) process complexity (which characterizes the type of products a refinery is capable of producing).

Capacity utilization rates of petroleum refineries have been rising in recent years, reaching a high of 92 percent in 1991.<sup>2</sup> This indicates that existing refineries are operating closer to full capacity than in the past, and will have limited opportunity to enhance production by increasing utilization.

During the past 23 years, the entire domestic refining industry has been affected by crude oil quantity changes and shifting petroleum demand patterns. A more complex and flexible refining industry has evolved domestically. Ownership of U.S. refineries has changed through consolidation and foreign investments. Throughout the 1970s, the number of U.S. refineries rose rapidly in response to rising demand for petroleum products. In the early 1980s, the petroleum refining industry entered a period of restructuring, which continued through 1992. A record number of U.S. refineries were operating in 1981. A decline in petroleum demand in the early 1980s caused many small refineries and older, inefficient plants to close. The refinery shutdowns resulted in improved operating efficiency, which enabled the refinery utilization rate to increase, despite lower crude oil inputs. Operable capacity has remained relatively constant since 1985, while capacity utilization has risen steadily.

*6.1.1.6 Refinery Complexity.* Complexity is a measure of the different processes used in refineries. It can be quantified by relating the complexity of a downstream process with atmospheric distillation, where atmospheric distillation is assigned the lowest value, 1.0. The level of complexity of a refinery generally correlates to the types of products the refinery is capable of producing. Higher complexity denotes a greater ability to enhance or diversify product output, to improve yields

of preferred products, or to process lower quality crude. By defining refinery complexity, it is possible to differentiate among refineries having similar capacities but different process capabilities. In theory, more complex refineries are more adaptable to change, and are therefore potentially less affected by regulation. The complexity of a refinery usually increases as its crude capacity increases. (Lube plants are the exception to this rule.) Over 50 percent of the operable capacity (50,000 to 100,000 bbl/d) can be found at refineries with above-average complexity. Likewise, the smaller refineries are less complex.

#### 6.1.2 Market Structure

The market structure of an industry will influence the magnitude of market impacts resulting from emission controls. A perfectly competitive market is characterized by many sellers, no barriers to entry or exit, homogeneous output, and complete information. A perfectly competitive market is one in which producers have small degrees of market power and pricing is determined by market forces, rather than by the producers. Alternatively an industry with monopoly power has more discretion over the market price charged. Producers in such an industry have greater market power. A profile of the market structure of the petroleum refining industry is provided in the following sections, including an assessment of the number of domestic operating refineries, the market concentration, and the extent of vertical integration, and diversification.

6.1.2.1 *Market Concentration.* Market concentration is a measure of the output of the largest firms in the industry, expressed as a percentage of total national output. Market concentration is usually measured for the 4, 8, or 20 largest firms in the industry. A firm's concentration in a market provides some indication of the firm's size distribution. For example, on one extreme, a concentration of 100 percent would indicate monopoly control of the industry by one firm. On the other extreme, concentration of less than 1 percent would indicate the industry was comprised of numerous small firms. Concentration is measured based on refining capacity. Until recently, the top four firms in the refining industry have

consistently comprised over 30 percent of the market share, but most market concentration ratios have marginally decreased in recent years.

Market concentration may also be evaluated using the Herfindahl-Hirschman index, which is defined as the sum of the squared market shares (expressed as a percentage) for all firms in the industry. If a monopolist existed, with market share equal to 100 percent, the upper limit of the index (10,000) would be attained. If an infinite number of small firms existed, the index would equal zero. An industry is considered *unconcentrated* if the Herfindahl-Hirschman index is less than 1,000. Ratings are also developed for moderately concentrated (between 1,000 and 1,800) and highly concentrated (greater than 1,800) industries. The petroleum refining Herfindahl-Hirschman index in recent years has been less than 500. Thus the refining industry is considered unconcentrated.<sup>3</sup>

6.1.2.2 *Industry Integration and Diversification.* Vertical integration exists when the same firm supplies input for several stages of the production and marketing process. Firms that operate petroleum refineries are vertically integrated because they are responsible both for exploration and production of crude oil (which supplies the input for refineries) and for marketing the finished petroleum products after refining occurs. To assess the level of vertical integration in the industry, firms are generically classified as *major* or *independent*. Generally speaking, major energy producers are defined as firms that are vertically integrated. There are currently 20 major energy companies. The crude capacity of the major, vertically integrated firms represents almost 70 percent of nationwide production.

For the major oil companies, horizontal integration exists because these firms operate several refineries which are often distributed around the nation. Seventy-three of the 109 firms in the industry operate only one refinery each. These are the smaller independent firms. The major firms operate several refineries, and the largest, Chevron, operates 13. Fourteen firms operate four or more refineries each.

Diversification exists when firms produce a wide array of unrelated products. In the short run, diversification may indirectly benefit firms that engage in petroleum refining, since the costs of control in petroleum refining may be dispersed over other unaffected businesses operated by the firm. Over the long term, however, firms will not subsidize petroleum product production with profit from other operations, but will shut down unprofitable operations instead. Diversification within the energy industry may mitigate some of the effects of regulation at least in the short run.

6.1.2.3 *Financial Profile.* The financial performance of firms in the petroleum refining industry is particularly relevant to an evaluation of the impact of regulation on the industry. In order to evaluate the financial condition of the refinery operations of firms, a sample of the petroleum refining industry's major firms financial operations were evaluated. Annual reports to stockholders were used as a source of data for the analysis. While this sample is too small and diverse to be considered representative of the aggregate industry, the data presented are more recent and more refinery-specific than American Petroleum Institute data.

The sample of annual report data analyzes refinery-specific data in order to provide a preliminary assessment of the financial condition of firms in the industry. This 12-firm sample as a whole operated 59 refineries in 1991, and represented 45.3 percent of the industry's total refining capacity. Refining capacity in the sample ranges from 165,000 bbl/d to 2,139,000 bbl/d. Over the 5-year period from 1987 to 1991, operating income per dollar of revenue increased from 1 percent to 4 percent. Capital expenditures increased steadily, while refined product sales continued a period of decline. The consolidation taking place in the refining industry is reflected in the decreasing crude oil capacity and refinery runs.

Refined product margins are a good indicator of overall refinery financial performance.<sup>4</sup> The difference between refined product costs and refined product revenues is the refined product margin. During the 1980s, refined product margins were affected

by a shift in product slates to gasoline and jet fuels, the decrease in crude oil prices, fluctuations in demand, and an increase in refinery utilization rates.<sup>5</sup> In constant 1982 dollars, the refined product margin fluctuated over this time frame, decreasing between 1985 and 1987 and then increasing significantly in 1988. The fluctuations in the refined product margins reflect the volatility of the market and the degree to which refineries' revenues are often subject to significant change over short time periods. In the early half of 1990, the margin between overall U.S. refined product prices and crude oil import costs rose to record levels, given falling crude oil prices and stable gasoline prices.<sup>6</sup> After the invasion of Kuwait, U.S. refined product prices did not keep pace with crude oil prices for the remainder of the year. This negatively impacted refinery revenues for 1991.

Firms have three sources of funding for the capital necessary to purchase emission control equipment required by the NESHAP. These sources include (1) internal funds, (2) borrowed funds, and (3) stock issues. Typically, firms seek a balance between the use of debt and stock issues for financing investments. Debt-to-equity ratios reflect a measure of the extent to which the firm has balanced the tax advantages of borrowing with the financial safety of stockholder financing. Based on information obtained in the annual reports of the 12 companies in the refinery sample, firms anticipate that internally generated funds will fund most of their capital expenditures. Other firms recognize the need to also draw on available credit lines and commercial paper borrowing. Overall, capital expenditures of refiners have doubled since 1977, although spending peaked in 1982 and has since been in a period of decline.

Planned uses of investment funds by the 12 firms in the financial sample over the next few years include construction of diesel desulfurization units, expansion of existing units, and construction of units to manufacture methyl tertiary butyl ether (MTBE) and oxygenated fuels. In a 1991 study, Cambridge Energy Research Associates (CERA) surveyed refiners and oxygenate producers to evaluate the ability of the refining industry to



meet CAA provisions.<sup>7</sup> Among the firms in the CERA survey, the majors and some large independents plan to fund their investments primarily or entirely from internally generated cash flows, while most of the small refineries surveyed are planning on resorting to the debt market for funds.

### 6.1.3 Market Supply

Refiners have increased production of most refined products almost every year since 1984. Historically, motor gasoline has been the product that is supplied in the greatest quantities to meet increased demand. Most of the other petroleum products show a modest net increase in supply over the past few years. The lack of significant change in the yield for most refined petroleum products indicates a relatively stable supply slate, but significant regulatory costs could force some reshuffling of product yield.

Refinery production of motor gasoline has increased each year, with the exception of periods of economic recession. Production remained relatively steady from 1988 to 1992. Distillate fuel oil output peaked at 3.3 million barrels per day in 1977, then fell through 1983. Output has increased slightly almost every year since, reaching 3 million barrels per day in 1992. Jet fuel production grew during the 1970s and 1980s, and almost doubled by 1990 before declining to 1.4 million barrels per day in 1992. Residual fuel oil production generally declined from 1980 through 1985, and was 1 million barrels per day in 1992, compared to 0.7 million barrels per day in 1970.

6.1.3.1 *Supply Determinants.* The most important short-run production decision for an oil refinery is the determination of how much crude oil to allocate for the production of each of the refinery's products. The production decision depends on the profit each of the oil products can generate for the firm. Profits, in turn, depend on the productivity of the oil refinery — its ability to produce each oil product as effectively as possible from a barrel of crude oil. The quantity of crude oil a refinery will refine depends on the capacity of the refinery and the cost of production. The marginal costs of production of each product will determine any future changes in production. Crude

oil is the primary material input to the refining process; as a result, the production of refined products is vulnerable to fluctuations in the world crude oil market.

In the long run, production decisions are based on the cost of capacity expansion relative to existing price levels and expected future price levels. A refinery uses different processing units to turn crude oil into finished products, so when a particular processing unit reaches capacity, output can be increased only by substituting a more expensive process. Firms will typically utilize sufficient crude oil to fill the appropriate processing unit until the price increases substantially. At this point, the firm would calculate whether the increased price warrants using an additional, more expensive processing unit.<sup>8</sup>

6.1.3.2 *Exports of Petroleum Products.* Some measure of the extent of foreign competition can be obtained by comparing exports to domestic production. Export levels and domestic refinery output for the past decade were analyzed. Exports as a percentage of domestic refinery output steadily increased from 1984 to 1991 and then fell slightly to 5.6 percent in 1992. Distillate oil, residual fuel oil, motor gasoline, and petroleum coke are exported in the highest volumes. The combined export volumes of these products represent 75 percent of domestic refinery output shipped overseas.

#### 6.1.4 *Market Demand Characteristics*

The end-use sectors that contribute to demand for refined petroleum products are classified in the following four economic sectors: (1) household and commercial, (2) industrial, (3) transportation, and (4) electric utilities. Petroleum products used as transportation fuel include motor gasoline, distillate (diesel) fuel, and jet fuel, and accounted for an estimated 64 percent of all U.S. petroleum demand in 1990. Since mobile source emissions will be regulated by Title II regulations, this output from petroleum refineries will be most affected by the CAA. The industrial sector constitutes the second highest percentage of demand for petroleum products, followed by household and electric utility demands.

Petroleum is used most widely in the transportation sector. In the household and commercial sector, light heating oil and propane are used for heating and energy uses, and compete with natural gas and electricity. Petroleum fuels in the industrial sector compete with natural gas, coal, and electricity. In the industrial sector, residual and distillate heating oils are used for boiler and power fuel. In the electric utility sector, petroleum products supply energy in the form of heavy residual fuel oil and smaller amounts of bulk light distillate fuel oil.<sup>9</sup>

In terms of refined products, the motor gasoline and jet fuel markets are associated with the transportation sector. The markets for distillate fuel oil are associated with the transportation sector (diesel engine fuel as a trucking fuel), household (space heating), industrial (fuel for commercial burner installations), and electric utilities (power generation). The sectors that are sources of demand for residual fuel oil include the commercial and industrial sectors (heating), utilities (electricity generation), and the transportation sector (fuel for ships). Nonutility use of residual fuel has been decreasing due to interfuel substitution in the commercial and industrial sectors. Because LPGs cover a broad range of gases, demand levels are attributable to various end users.

6.1.4.1 *Demand Determinants.* The demand for refined petroleum products is primarily determined by price level, the price of available substitutes, and economic growth trends. The degree to which price level influences the quantity of petroleum products demanded is referred to as the *price elasticity of demand*, which is explored later in this report. Prices of refined petroleum products affect the willingness of consumers to choose petroleum over other fuels, and may ultimately cause a change in consumer behavior. In the transportation sector, the effect of high gasoline prices on fuel use could reduce discretionary driving in the short term and, in the long term, result in the production of more fuel-efficient vehicles.

In the market for jet fuel, demand is primarily determined by a combination of price concerns and the overall health of the airline industry. In the residential sector, demand for home

heating (distillate) is determined in part by price level, and also by temperature levels and climate. Temperature in different areas of the country may determine the degree to which buildings and houses are insulated. Temperature and insulation are exogenous factors which will determine heating needs regardless of the price level of fuel. High prices for home heating oil provide incentive for individuals to conserve by adjusting thermostats, improving insulation, and by using energy-efficient appliances. In some cases, higher oil prices also provide incentive for switching to natural gas or electric heating. (Adjusting thermostats is a short-run response, while changing to more energy-efficient appliances or fuels are long-run responses.)

In the industrial sector, fuel oil competes with natural gas and coal for the boiler-feed market. High prices relative to other fuels tend to encourage fuel-switching, especially at electric utilities and in industrial plants having dual-fired boilers. Generally speaking, in choosing a boiler for a new plant, management must choose between the higher capital/lower operating costs of a coal unit or the lower capital/higher operating costs of a gas-oil unit. In the utility sector, most new boilers in the early 1980s were coal-fired due to the impact of legislative action, favorable economic conditions, and long-term assured supplies of coal.<sup>10</sup> Today, because the CAA will require utilities to scrub or use a low-sulfur fuel, oil will eventually become more competitive with coal as a boiler fuel, although a significant increase in oil-fired capacity is not expected until 2010.<sup>11</sup>

Demand levels in each of the end-use sectors are also affected by the economic environment. Periods of economic growth and periods of increased demand for petroleum products typically occur simultaneously. For example, in an expanding economy, more fuel is needed to transport new products, to operate new production capacity, and to heat new homes. Conversely, in periods of low economic growth, demand for petroleum products decreases.

6.1.4.2 *Past and Present Consumption.* Total consumption of all types of petroleum products has fluctuated over the past 20 years, reflecting the volatility of this market. The consumption level has been sporadic and has shown an overall decline in recent years. Demand for individual petroleum product types has also fluctuated over this period. The percentage of total demand is highest for motor gasoline followed by demand for distillate fuel oil. Over the 23-year period from 1970 to 1992, the demand for residual fuel oil has decreased by 50 percent, showing the greatest percentage of change over time of any of the petroleum products. It has also been the only fuel to show a decline in use. This decrease in residual fuel demand reflects a move in the industry from heavier fuels toward lighter, more refined versions. This trend is expected to continue into the future as efforts to control air emissions go into effect.

All other types of fuel show increases in use, with the most growth occurring in the market for jet fuel. Substantial gains in airplane fuel efficiency in the last two decades, which have resulted from improved aerodynamic design and a shift toward higher seating capacities, have been exceeded by even faster growth in passenger miles traveled.<sup>12</sup> The other categories show an average growth rate of approximately 23 percent over this time period. All major petroleum products registered lower demand in 1991 than in 1990, except LPGs. This was the first time since 1980 that demand for all major petroleum products fell simultaneously in the same year. In this case, decreased demand was brought on by warmer winter temperatures, an economic slowdown, and higher prices resulting from the Persian Gulf situation.<sup>13</sup>

Motor gasoline demand increased from a 1970 low to a high of 7.4 million barrels per day in 1978. The increase reflected a 31 percent growth in the number of automobiles in use and a 25 percent growth in vehicle miles traveled. From 1985 to 1992, motor gasoline use accounted for about 42 percent of all petroleum products consumed.

Changes in demand for distillate fuel oil were similar to motor gasoline in that consumption reached its lowest and highest

levels in 1970 and 1978, respectively. Between 1985 and 1992, consumption was relatively stable and accounted for about 18 percent of total U.S. petroleum consumption. Residual fuel oil demand, in response to lower-priced natural gas and other factors, fell 64 percent, from a high in 1977 of 3.1 million barrels per day to 1.1 million barrels per day in 1992.

Between the period from 1970 to 1990, expanding air travel spurred a 57 percent growth in jet fuel demand. Demand increased from a 1970 low of 1.0 million barrels per day to 1.5 million barrels per day in 1990.

The variation in U.S. petroleum product demand has been linked to changes in the prices of petroleum products relative to one another, and relative to other energy sources. Dramatic petroleum price increases and eventual steep drops were in response to wars, political upheaval in crude oil producing areas, and supply disruptions during the past two decades. During this period, the more stable and lower prices of alternative fuels led consumers to switch from petroleum as their fuel of economic choice.

6.1.4.3 *Imports of Refined Petroleum Products.* Imports as a percentage of domestic consumption have fluctuated during the period 1981 through 1992, although in 1992 levels were 10.6 percent, or roughly the same level as in 1981. The import to export ratio has decreased since 1981, due primarily to steady increases in exports.

6.1.4.4 *Pricing.* Prices for petroleum products have shown volatility over the time period from 1978 through 1992. This volatility is mainly attributable to the fluctuations in the global market for crude oil and the inelastic demand for petroleum products. Inelastic demand allows refiners to pass crude oil price increases on to consumers. Since petroleum products are essentially commodity products and are produced by a large number of refineries, refineries have little ability to differentiate products or their prices.

#### 6.1.5 *Market Outlook*

Quantitative production, demand, and price projections are available from the literature. Projections are important to the

economic impact analysis since future market conditions contribute to the potential impacts of the NESHAP which are assessed for the fifth year after regulation.

6.1.5.1 *Supply Outlook (Production and Capacity)*. The refining industry was operating near maximum capacity in 1991, with an average annual utilization rate of approximately 92 percent.<sup>14</sup> This is an increase from levels of previous years. In the market for motor gasoline, for example, production capacity is nearly at full capacity. As a result, any increases in demand will have to be met by imported products. This will result in an increase in worldwide competition for gasoline. East Coast refiners, accounting for more than 90 percent of all unleaded gas imports to the United States, will be most affected by this increased competition.<sup>15</sup> DOC predicts that, although U.S. refinery output will remain relatively unchanged, net imports of refined petroleum products are expected to increase by 15 percent.<sup>16</sup> DOE predicts net petroleum imports will rise to at least 10 million bbl/d in 2010, and perhaps as high as 15 million bbl/d from the 1990 level of 7 million bbl/d as domestic oil production is expected to decline. Imports are expected to supply between 53 and 69 percent of U.S. petroleum consumption by 2010, compared with 42 percent in 1990. Refined products will account for much of this increase because most of the expansion in the world's refinery system is expected to take place outside the United States.<sup>17</sup>

Over the next 5 years, the petroleum industry as a whole plans to increase crude oil distillation capacity by an additional 2 percent, or 272,000 bbl/d, of which 44 percent would be produced by new facilities.<sup>18</sup> (The other 56 percent includes reactivations and expansions.) The level of added demand will determine if this added capacity is sufficient to satisfy the market without driving up prices.

Companies that operate refineries with greater complexity factors (often the largest refineries) will presumably be in a more favorable position to make the necessary capital investments for the transition to cleaner fuels. Such refineries will most likely be those large enough to benefit from the economies of

scale, and with basic downstream configurations to facilitate compliance with the new regulations. A financial analysis of major petroleum refineries in the 1980s conducted by DOE concluded that vertically integrated firms benefitted in a period characterized by increased regulatory activity and price instability.<sup>19</sup> The report found that the larger companies could offset a loss in one segment with gains in another. (It is important to note, however, that in the long run, both large and small firms would close refineries which operate at a loss over time.)

In contrast, smaller, independent, and less complex refineries will face higher marginal compliance costs, and may not find it economical to spend the required environmental capital. Generally not as flexible as the larger, integrated companies, these firms operate at greater risk from the effects of market instability. As a result, an industry which has seen a high level of consolidation in past years will be likely to see more concentration.<sup>20</sup>

Overall, the effect of the CAA on individual refineries is dependent upon production capacity, economies of scale, degree of self-sufficiency, capital cost, and ability of refiners to "pass through" higher costs to consumers. Predictions of the effect on the aggregate industry are difficult at this time because of the uncertainty of the ability of some refineries to develop plans for compliance pending resolution of key issues affecting their operations. A recent Harvard University study, however, predicted that the promulgation of environmental regulations was likely to result in the early phase out of older, less sophisticated facilities, combined with the upgrade and expansion of more efficient, complex refineries at a faster rate.<sup>21</sup>

6.1.5.2 *Demand Outlook.* The U.S. Department of Commerce (DOC) projects the demand for all petroleum products to rise slowly and steadily over the next 5 years, with domestic demand for refined products increasing by 2.1 percent in 1992, assuming an economic recovery and a return to "normal" weather. DOC's longer term demand prediction is for a steady growth rate of 1 percent through 1996.<sup>22, 23</sup> Given that two-thirds of petroleum



product demand is attributable to the transportation sector, projected demand growth for motor gasoline will have the greatest effect on refiners. Industrial demand for distillate fuel reflects the strongest projected growth. According to DOE projections, the consumption of diesel fuel in the transportation sector is expected to grow by over 40 percent between 1990 and 2010.<sup>24</sup> Residential and commercial sectors are expected to show a decrease in demand for petroleum products.

DOE has also projected future levels of demand. Motor gasoline will remain the leading end use of petroleum products throughout DOE's chosen time frame, dropping off during 1990 and 1995, and rising again to higher levels by 2010. DOE predicts the demand for residual oil to rise, level off, and then begin to decline in 2010. Jet fuel and distillate fuel are both projected to rise steadily through 2010.

6.1.5.3 *Price Outlook.* Given that the demand for motor gasoline is price inelastic, the added capital investment that refineries will be required to undertake in the production of reformulated gasolines is likely to be passed on to consumers in the form of a price increase. DOE has estimated this price increase to be a 5 to 10 cent-per-gallon rise in the price of motor gasoline.<sup>25</sup> In a recent study undertaken by the National Petroleum Council, the impacts of air quality regulations on petroleum refineries were assessed. One of the conclusions of the study was that the costs of controlling air emissions are likely to be passed along to consumers as increases in the final price of refined products. (The study offered no quantitative projections, however.)<sup>26</sup>

DOE has projected the domestic prices of petroleum products for 2010. DOE projects the average price for all petroleum prices to increase at a rate in the range of 0.4 percent to 2.1 percent annually. These price increases are due to projected increases in both domestic demand and crude oil prices. DOE also accounted for higher refining and distribution expenses in making these projections. The real price of motor gasoline is projected to rise from \$1.17 per gallon in 1990 to between \$1.30 and \$1.74 in 2010, depending on the level of world crude oil prices. On-

highway diesel fuel is projected to increase to between \$1.27 and \$1.69 per gallon, primarily because of the added refinery costs of desulfurization. The average retail price of residual fuel oil, the least expensive petroleum product, is projected to be within the range of \$25.52 to \$40.79 per barrel in 2010.

If refineries are able to accommodate projected increases in demand, the price level will remain fairly stable. However, because the price level in this industry is contingent upon so many factors independent of the industry, any price predictions necessarily have their limitations. In the long run, therefore, price predictions will need to be modified with the occurrence of any world events which will affect the supply of crude oil to the refineries and therefore to the supply of refined petroleum products. Refineries will also be faced with increasing levels of emission restrictions, escalating their pollution abatement costs, and consequently, the price of their products.

## 6.2 MARKET MODEL

A partial equilibrium model is the analytical tool used to estimate the impact of the final NESHAP on the petroleum refining industry. Five refined petroleum products were modeled. Collectively, these products represent over 90 percent of the refined petroleum products sold in the nation annually. These products include motor gasoline, jet fuel, residual fuel oil, distillate fuel oil, and liquified petroleum gases (LPGs). It is assumed that firms in the petroleum refining industry operate in a perfectly competitive market. Although the petroleum refinery industry does not meet the strictest definition of a perfectly competitive industry, perfect competition seems a more applicable characterization of the market than pure monopoly. The assumption of perfect competition results in a worst case scenario of model results from the perspective of the impact of the regulation on the petroleum refinery industry.

### 6.2.1 *Market Supply and Demand*

The partial equilibrium model approach estimates the baseline market supply and demand relationship that provides the framework for evaluating market changes likely to occur from emission

controls. The baseline or pre-control petroleum refining market is defined by a domestic market demand equation, a domestic market supply equation, and a foreign market supply equation. It is further assumed that the markets will clear or achieve an equilibrium. The following equations identify the market demand, supply, and equilibrium conditions for the petroleum refinery industry:

$$Q^D = \alpha P^\epsilon$$

$$Q^{S_d} = \beta P^\gamma$$

$$Q^{S_f} = \rho P^\gamma$$

$$Q^D = Q^{S_d} + Q^{S_f} = Q$$

where:

- $Q$  = annual output or quantity of petroleum products purchased and sold in the United States
- $Q^D$  = quantity of the petroleum products domestically demanded annually
- $Q^{S_d}$  = quantity of the products produced by domestic suppliers annually
- $Q^{S_f}$  = quantity of the products produced by foreign suppliers annually
- $P$  = price of the petroleum product
- $\epsilon$  = price elasticity of demand for the product
- $\gamma$  = price elasticity of supply for the product
- $\alpha$ ,  $\beta$ , and  $\rho$  are parameters estimated by the model.

The constants  $\alpha$ ,  $\beta$ , and  $\rho$  are computed such that the baseline equilibrium price is normalized to one. The market specification assumes that domestic and foreign supply elasticities are the same. This assumption was necessary because data were not readily available to estimate the price elasticity of supply for foreign suppliers.

#### 6.2.2 Market Supply Shift

The domestic supply equation shown above may be solved for the price of the petroleum product,  $P$ , to derive an inverse supply function that will serve as the baseline supply function for the industry. The inverse domestic supply equation for the industry is as follows:

$$P = (Q^S/\beta)^{\frac{1}{\gamma}}$$

A rational profit maximizing business firm will seek to increase the price of the product it sells by an amount that recovers the capital and operation costs of the regulatory control requirements over the useful life of the emission control equipment. This relationship is identified in the following equation:

$$\frac{[(C \cdot Q) - (V + D)] (1 - t) + D}{S} = k$$

where:

- $C$  = increase in the supply price
- $Q$  = output
- $V$  = measure of annual operating and maintenance control costs
- $t$  = marginal corporate income tax rate
- $S$  = capital recovery factor
- $D$  = annual depreciation (assumes straight line depreciation)
- $k$  = investment cost of emission controls

Thus, the model assumes that individual refineries will seek to increase the product supply price by an amount ( $C$ ) that equates the investment costs in control equipment ( $k$ ) to the present value of the net revenue stream (revenues less expenditures) related to the equipment. Solving the equation for the supply price increase ( $C$ ) yields the following equation:

Estimates of the annual operation and maintenance control costs and of the investment cost of emission controls ( $V$  and  $k$ ,

$$C = \frac{kS - D}{Q(1 - t)} + \frac{V + D}{Q}$$

respectively) were obtained from engineering studies conducted by the engineering contractor for EPA and are based on first quarter 1992 price levels. The variables depreciation and capital recovery factor,  $D$  and  $S$ , respectively, are computed as follows:

$$D = \frac{k}{T}$$

$$S = \frac{r(1 + r)^T}{[(1 + r)^T - 1]}$$

where  $r$  is the discount rate faced by producers and is assumed to be a rate of 10 percent, and  $T$  is the life of the emission control equipment, 10 years for most of the emission control equipment proposed.

Emission control costs will increase the supply price for each refinery by an amount equivalent to the per unit cost of the annual recovery of investment costs and annual operating costs of emission control equipment, or  $C_i$  ( $i$  denotes domestic refinery 1 through 192). The baseline individual refinery cost curves are unknown because production costs for the individual refineries are unknown. Therefore, an assumption is made that the refineries with the highest after-tax per unit control costs are marginal in the post-control market, or that those firms with the highest after tax per unit control costs also have the highest per unit production costs. This is an assumption that likely causes overestimates of impacts and may not be the case in reality. Based upon this assumption, the post-control supply function becomes the following:

$$P = (Q^S/\beta)^{\frac{1}{\gamma}} + C(C_i, q_i)$$

where:

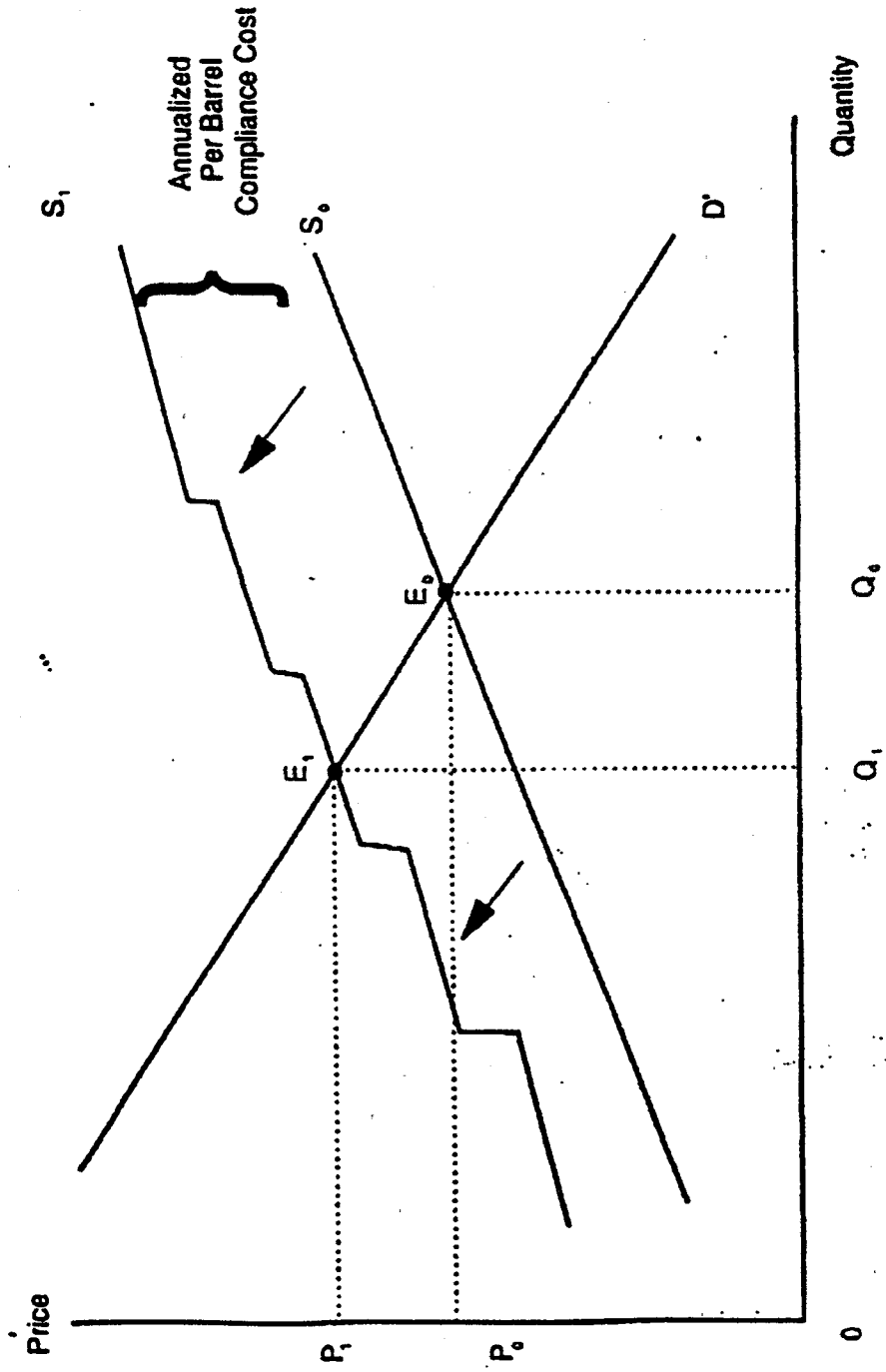
$C(C_i, q_i)$  = a function that shifts the supply function to  
reflect control costs

$C_i$  = vertical shift that occurs in the supply curve for  
the  $i$ th refinery to reflect the increased cost of  
production in the post-control market

$q_i$  = quantity produced by the  $i$ th refinery

This industry pre-control and post-control supply and demand is  
illustrated in Figure 6-1.

FIGURE 6-1. ILLUSTRATION OF POST-NESHAP MODEL



### 6.2.3 *Impact of Supply Shift on Market Price and Quantity*

The impact of the proposed control standards on market equilibrium price and output are derived by solving for the post-control market equilibrium and comparing the new equilibrium price and quantity ( $P_1$  and  $Q_1$ , respectively) to the pre-control equilibrium ( $P_0$  and  $Q_0$ ). The change in value of domestic product is simply the difference in the industry revenue ( $P_1 * Q_1$ ) at the post-control market equilibrium and the revenue ( $P_0 * Q_0$ ) at the pre-control equilibrium.

Those firms that lie on the industry supply curve at price and quantity levels above the post-control equilibrium ( $P_1, Q_1$ ) are subject to closure. This assumption is consistent with the assumption of perfect competition. Firms in a competitive market are price takers and are unable to sell their products at prices above the market equilibrium.

Predicted primary market impacts become the basis for assessing economic surplus changes; secondary labor, energy, and foreign trade market impacts; and the capital availability consequences expected to result from the emission controls.

### 6.2.4 *Trade Impacts*

Trade impacts are reported as the change in both the volume and dollar value of net exports (exports minus imports). It is assumed that exports comprise an equivalent percentage of domestic production in the pre- and post-control markets. The supply elasticities in the domestic and foreign markets have also been assumed to be identical. As the volume of imports rises and the volume of exports falls, the volume of net exports will decline. However, the dollar value of net exports may rise or fall when demand is inelastic, as is the case for the petroleum products of interest. The dollar value of imports will increase since both the price and quantity of imports increase. Alternatively, the quantity of exports will decline, while the price of the product will increase. Price increases for products with inelastic demand result in revenue increases for the producer. Consequently, the dollar value of exports is anticipated to increase. Since the dollar value of imports and exports rise, the resulting change in the value of net exports



will depend on the magnitude of the changes for imports relative to exports. The following functions are used to compute the trade impacts:

$$\Delta Q^{S_f} = Q_1^{S_f} - Q_0^{S_f}$$

$$\Delta VIM = (P_1 \cdot Q_1^{S_f}) - (P_0 \cdot Q_0^{S_f})$$

$$\Delta Q_x^{S_d} = \frac{Q_x^{S_d}}{Q_0^{S_d}} (Q_1^{S_d} - Q_0^{S_d})$$

$$\Delta VX = \frac{Q_x^{S_d}}{Q_0^{S_d}} (P_1 Q_1^{S_d} - P_0 Q_0^{S_d})$$

where:

- $\Delta Q^{S_f}$  = change in the volume of imports
- $\Delta VIM$  = change in the dollar value of imports
- $\Delta Q_x^{S_d}$  = change in the volume of exports
- $\Delta VX$  = change in the dollar value of exports
- $Q_x^{S_d}$  = quantity of exports by domestic producers in the pre-control market

The subscripts 1 and 0 refer to the post- and pre-control equilibrium values, respectively. All other terms have been previously defined.

The change in the quantity of net exports,  $\Delta NX$ , is simply the difference between the change in the volume of exports and the change in volume of imports, or  $\Delta Q_x^{S_d} - \Delta Q^{S_f}$ . The reported change in the dollar value of net exports,  $\Delta VNX$ , is the difference between the equations for change in value of exports and the change in value of imports, or  $\Delta VX - \Delta VIM$ .

#### 6.2.5 Changes in Economic Welfare

Regulatory control requirements will result in changes in the market equilibrium price and quantity of petroleum products produced and sold. These changes in the market equilibrium price and quantity will affect the welfare of consumers of petroleum products, producers of petroleum products, and society as a whole.

Consumer surplus is a measure of the well-being of consumers of a particular product and it represents the net benefit (total benefits derived from consuming a good less the expenditure necessary to purchase the good) associated with consuming a particular product. Consumers of refined petroleum products will bear a loss in consumer surplus as a result of proposed emission controls. This loss in consumer surplus ( $\Delta CS$ ) represents the amount consumers would have been willing to pay over the pre-control price for production eliminated and a loss due to the increase in the market price consumers must pay for the quantity of petroleum products purchased.

The change in consumer surplus includes losses of surplus incurred by foreign consumers and domestic consumers. Although the change in domestic consumer surplus is the object of interest, no method is available to distinguish the marginal consumer as domestic or foreign. Therefore, an assumption is made that the consumer surplus change is allocable to the foreign and the domestic consumer in the same ratio as the division of sales between foreign and domestic consumers in the pre-control market. The variable,  $\Delta CS_d$ , represents the change in domestic consumer surplus that results from the change in market equilibrium price and quantity resulting from the imposition of regulatory controls. While  $\Delta CS$  is the change in consumer surplus from the perspective of the world economy,  $\Delta CS_d$  is the change in consumer surplus relevant to the domestic economy.

Producer surplus is a measure of well-being of producers in an industry. The change in producer surplus resulting from emission controls is composed of two elements. The first element relates to output eliminated as a result of controls. The second element is associated with the change in price and cost of production for the new market equilibrium quantity. The total change in producer

surplus is the sum of these elements. After-tax measures of surplus changes are required to estimate the impacts of controls on producers' welfare. The after-tax surplus change is computed by multiplying the pre-tax surplus change by a factor of 1 minus the tax rate,  $(1-t)$  where  $t$  is the marginal tax rate. Every dollar of after-tax surplus loss represents a complimentary loss in tax revenues of  $t/(1-t)$  dollars.

Output eliminated as a result of control costs cause producers to suffer a welfare loss in producer surplus. Refineries operating in the post-control market realize a welfare gain on each unit of production for the incremental increase in the price and realize a decrease in welfare per unit for the capital and operating cost of emission controls. The total change in producer surplus ( $\Delta PS$ ) is the sum of each individual change in producer surplus.

Since domestic surplus changes are the object of interest, the welfare gain experienced by foreign producers due to higher prices is not considered. This procedure treats higher prices paid for imports as a dead-weight loss in consumer surplus. Higher prices paid to foreign producers represent simply a transfer of surplus from the United States to other countries from a world economy perspective, but a welfare loss from the perspective of the domestic economy.

The changes in economic surplus as measured by the change in consumer and producer surplus previously discussed must be adjusted to reflect the true change in social welfare resulting from the emission controls. Adjustments must be made to consider tax effects and to adjust for the difference between the social discount rate and the private discount rate. These adjustments result in a number referred to as the residual surplus to society since these surplus changes do not relate specifically to consumers or producers of refined petroleum products, but rather reflect losses that must be borne by all members of society.

Two adjustments are necessary to adjust changes in economic surplus for tax effects. The first relates to the per unit control cost ( $C_i$ ) that reflects after-tax control costs and is

used to predict the post-control market equilibrium. True cost of emission controls must be measured on a pre-tax basis. A second tax-related adjustment is required because changes reflect the after-tax welfare impacts of emission control costs on affected refineries. As noted previously, a one dollar loss in pre-tax surplus imposes an after-tax burden on the affected refinery of  $(1-t)$  dollars. Alternatively, a one dollar loss in after-tax producer surplus causes a complimentary loss of  $t/(1-t)$  dollars in tax revenue.

Economic surplus must also be adjusted because the private and social discount rates differ. The private discount rate is used to shift the supply curve of firms in the industry since this rate reflects the marginal cost of capital to affected firms. The shift in the supply curve for the refining industry is used to estimate primary and secondary market impacts. A private cost of capital of 10 percent is assumed for the analysis.

In contrast, the economic costs of regulation must consider the social cost of capital rather than the private cost of capital. A social cost of capital of 7 percent is assumed for the analysis. This rate reflects the social opportunity cost of resources displaced in the economy by investments required for emission controls. The adjustment for the two tax effects and the social cost of capital are referred to as the residual change in economic surplus to society ( $\Delta RS$ ).

The total economic costs of the proposed regulations are the sum of the changes in consumer surplus, producer surplus, and the residual surplus to society. This relationship is defined by the following equation:

$$EC = \Delta CS_d + \Delta PS + \Delta RS$$

where  $EC$  is the economic cost of the proposed controls and all other variables have been previously defined.

#### 6.2.6 Labor Market and Energy Market Impacts

Emission control costs will result in a decrease in the market equilibrium quantity of refined products produced and sold domestically. This reduction in output or production will directly cause the level of inputs used in production to decrease. Quantification of the input reduction affecting the labor and energy markets are of particular interest.

Two adjustments in the labor market may result from the emission controls. The first involves monitoring and maintenance of the emission control equipment that may cause employment increases. Information necessary to quantify potential employment increases for monitoring and maintenance of emission controls is not readily available. Consequently, possible employment increases are not considered in the analysis. Additionally, job losses may occur as a result of decreases in the level of production for firms in the industry. Probable job losses due to the estimated decrease in refined petroleum output are quantified by multiplying the decrease in industry output by an industry ratio of employees per unit of production. This quantification of possible job losses in the refining industry is likely to be overstated due to the omission of potential job increases for monitoring and maintenance of emission control equipment.

Reduction in the utilization of energy inputs associated with the final standard result from decreases in output in the industry. The expected change in expenditures on energy by firms in the industry is calculated by multiplying the ratio of baseline energy expenditure per dollar refined petroleum output by the estimated decrease in annual output. The quantification of energy input changes reflects energy expenditure decreases per year occurring as a result of the reduced production of refined petroleum products.

#### 6.2.7 *Baseline Inputs*

The partial equilibrium model requires, as data inputs, baseline values for variables and parameters that characterize the petroleum refining market. These data inputs include the number of domestic refineries in operation in 1992, the annual production per refinery for 1992, and the relevant control costs

per refinery. All monetary values are based upon 1992 price levels. Specific details concerning the data inputs and the sources of the data are available in the *Economic Impact Analysis of the Petroleum Refinery NESHAP* (1995).

Two data inputs crucial to the estimation of partial equilibrium are the price elasticity of demand and the price elasticity of supply. The price elasticities of supply and demand are briefly discussed in the following section.

#### 6.2.8 Price Elasticities of Demand and Supply

Price elasticities of demand and supply are measures of the responsiveness of buyers and sellers of a product to changes in the market price. Elasticity measures may be categorized as elastic, unitary elastic, and inelastic to price changes in the market. Products with elastic price elasticity values are very responsive to changes in the price of the product (percent quantity decrease exceeds percent price increase) while products with inelastic price elasticity measures are not very responsive to changes in price (percent quantity decrease is less than percent price increase). Unitary elasticity measures have equal percent changes in price and quantity. The ultimate increase in market equilibrium price and decrease in market equilibrium quantity resulting from emission controls are dependent upon the magnitude of the per unit control costs and elasticity measures in the market. The relative burden of emission control costs between consumers and producers will be determined by the comparative magnitudes of the supply and demand elasticities prevailing in a market, all other factors being equal. The more inelastic demand is for a product, the larger the share of emission control costs that will be paid by consumers of the product in the form of higher product prices. Alternatively, the more inelastic the supply curve, the larger the share of emission control costs that will be paid by suppliers.

6.2.8.1 *Price Elasticity of Demand.* The price elasticity of demand represents the percentage change in the quantity demanded resulting from each 1 percent change in the price of the product. Petroleum products represent a very important energy source for the United States. Many studies have been conducted which

estimate the price elasticity of demand for some or all of the petroleum products of interest and numerous published sources of the price elasticity of demand for petroleum products exist. These elasticity measures are used in the analysis and are listed in Table 6-1. Sources of these data are discussed in detail in the *Industry Profile for the Petroleum Refinery NESHAP* (1993).

TABLE 6-1. ESTIMATES OF PRICE ELASTICITY OF DEMAND

FUEL TYPE	ELASTICITY RANGE	MID-POINT ELASTICITY
Motor Gasoline	-0.55 to -0.82 <sup>27</sup>	-0.69
Jet fuel	-0.15 <sup>28</sup>	-0.15
Residual Fuel Oil	-0.61 to -0.74 <sup>27</sup>	-0.675
Distillate Fuel Oil	-0.50 to -0.99 <sup>27</sup>	-0.745
Liquified Petroleum Gas	-0.60 to -1.0 <sup>27</sup>	-0.80

The elasticity estimates for each of the products reflect that each of these products have inelastic demand. The only exception is the upper end of the range of elasticities for LPGs that is unitary elastic. As previously stated, regulatory control costs are more likely to be paid by consumers of products with inelastic demand when compared to elastic demand, all other things held constant. Price increases for products with inelastic demand lead to revenue increases for producers of the product. Thus, one can predict that price increases resulting from implementation of regulatory control costs will lead to higher revenues for the petroleum refining industry, all other factors held constant. The market changes resulting from the regulations are based upon the midpoint of the range of demand elasticities. A sensitivity analysis of this assumption was made using the upper and lower bounds of the range of elasticities.

6.2.8.2 *Price Elasticity of Supply.* The price elasticity of supply or own-price elasticity of supply is a measure of the responsiveness of producers to changes in the price of a product. The price elasticity of supply indicates the percentage change in the quantity supplied of a product resulting from each 1 percent change in the price of the product.

Published sources of the price elasticity of supply using current data were not readily available. It was determined that the price elasticity of supply should be estimated econometrically using time series data. Several estimation approaches were considered and are discussed in detail in the *Economic Impact Analysis of the Petroleum Refinery NESHAP* (1995). The approach actually used to estimate the price elasticity of supply was a time series model of the production function for the petroleum refining industry. Relevant factors of production in the model included labor, capital, and materials (crude oil). The econometric results of the production function estimation and efficient market assumptions were used to derive a price elasticity of supply for the petroleum products of interest of 1.24. This estimate of the price elasticity of supply for the five petroleum products reflects that the petroleum refinery industry in the U.S. will increase production of gasoline, jet fuel, residual fuel oil, distillate fuel oil and LPGS jointly by 1.24 percent for every 1.0 percent increase in the price of these products. Elasticity measures for the individual products were not calculated due to statistical modeling problems. Limitations of the elasticity measure estimate are discussed in detail in the *Economic Impact Analysis* and in a limited manner in 6.4 *Limitations of the Economic Model.*

### 6.3 CAPITAL AVAILABILITY ANALYSIS

It is necessary to estimate the impact of the proposed emission controls on the financial performance of affected petroleum refineries and on the ability of the refineries to finance the additional capital investment in emission control equipment. Financial data were not available for the majority of the refineries in the industry. Available data were obtained



only for the largest publicly held petroleum refining companies. For this reason, the capital availability analysis has been conducted on an industrywide basis.

One measure of financial performance frequently used to assess profitability of a firm is net income before interest expense as a percentage of firm assets or rate of return on investment. The pre-control rate of return on investment (*roi*) is calculated as follows:

$$roi = \left[ \sum_{i=1986}^{1990} \left( \frac{n_i}{a_i} \right) \right] / 5 \cdot 100$$

where  $n_i$  is income before interest payments and  $a_i$  is total assets. A five-year average is used to avoid annual fluctuations that may occur in income data. The proposed regulations potentially could have an effect on income before taxes  $(n)_i$  for firms in the industry and on the level of assets for firms in the industry  $(a_i)$ . Since firm specific data were unavailable for all of the affected firms, sample financial data collected by the American Petroleum Institute (API) were used.<sup>29</sup> Data from the API study are available in *Industry Profile for the Petroleum Refinery NESHAP*. The sample studied by API represents 71 percent of net income in the industry and 70 percent of total industry assets. These percentages are considered to estimate changes in the financial ratios and are necessary to allocate changes in income and assets resulting from emission controls to the study sample. There is a great diversity among the refineries in the industry; therefore, individual firm financial performance may vary greatly from the sample estimate. The post-control return on investment (*proi*) is calculated as follows:

$$proi = \left[ \frac{\left( \sum_{i=1986}^{1990} n_i \right) / 5 + \Delta n}{\left( \sum_{i=1986}^{1990} a_i \right) / 5 + k} \right] \cdot 100$$

where:

- proi* = the post-control return on investment
- $\Delta n$  = the change in income before interest resulting from implementation of emission controls for firms in the sample
- $\Delta k$  = capital expenditures associated with emission controls.

The equation *proi* will tend to overstate the impact of the control measure on the rate of return on investment for the industry over the life of the emission controls. This is true because net capital investment in emission controls will decline as capital is depreciated.

The ability of affected firms to finance the capital equipment associated with the emission control is also relevant to the analysis. Numerous financial ratios can be examined to analyze the ability of a firm to finance capital expenditures. One such measure is historical profitability measures such as rate of return on investment. The analysis approach for this measure has been previously described. The bond rating of a firm is another indication of the credit worthiness of a firm or the ability of a firm to finance capital expenditures with debt capital. Such data are unavailable for many of the firms subject to the regulation, and consequently bond ratings are not analyzed. Ability to pay interest payments is another criterion sometimes used to assess the capability of a firm to finance capital expenditures. Coverage ratios provide such information. The interest coverage ratio, or the number of times income (before taxes and interest) will pay interest expense, is a ratio that provides some information about the ability of a firm to cover or

pay annual interest obligations. The pre-control measure of coverage ratio is as follows:

$$tc = \left( \sum_{i=1986}^{1990} \frac{ebit_i}{interest_i} \right) / 5$$

where:

$tc$  = number of times earnings will pay annual interest charges

$ebit$  = earnings before interest payments and taxes

$interest_i$  = annual interest expense

Post-control coverage ratios may be estimated as follows:

$$ptc = \frac{\left( \sum_{i=1986}^{1990} ebit_i \right) / 5 + \Delta ebit}{\left( \sum_{i=1986}^{1990} interest_i \right) / 5 + \Delta interest}$$

where:

$\Delta ebit$  = estimated change in earnings before interest and taxes of the firm

$\Delta interest_i$  = anticipated change in interest expense

All other variables have been previously described. The  $\Delta interest$  is calculated by multiplying the capital expenditures for the proposed controls ( $\Delta k$ ) by the assumed private cost of capital (10 percent). This is generally lower than the overall cost of capital for a firm. Again the interest coverage ratios of individual petroleum refineries may differ from the average significantly.

Finally, the degree of debt leverage or debt-equity ratio of a firm is considered in assessing the ability of a firm to finance capital expenditures. The pre-control debt-equity ratio is the following:

where:

$d/e$  = debt equity ratio

$$d/e = \frac{d_{1990}}{d_{1990} + e_{1990}}$$

$d$  = debt capital  
 $e$  = equity capital

Since capital information is less volatile than earnings information, it is appropriate to use the latest available information for this calculation. If one assumes that the capital costs of control equipment are financed solely by debt, the debt-equity ratio becomes:

$$pd/e = \frac{d_{1990} + k}{d_{1990} + e_{1990} + k}$$

where  $pd/e$  is the post-control debt-equity ratio assuming that the control equipment costs are financed solely with debt. Obviously, firms may choose to issue capital stock to finance the capital expenditure or to finance the investment through internally generated funds. The assumption that the capital costs are financed solely by debt may be viewed as a conservative scenario.

The methods used to analyze the capital availability do have some limitations. The approach matches 1990 debt and equity values with estimated capital expenditures for control equipment. Average 1986 through 1990 income and asset measures are matched with changes in income and capital expenditures associated with the control measures. The control cost changes and income changes reflect 1992 price levels. The financial data used in the analysis represents the most recent data available. It is inappropriate to simply index the income, asset, debt, and equity values to 1992 price levels for the following reasons. Assets, debt, and equity represent embedded values that are not subject to price level changes except for new additions such as capital expenditures. Income is volatile and varies from period to period. For this reason, average income measures are used in the study. The analysis reflects a conservative approach to

analyzing the changes likely in financial ratios for the petroleum industry. Some decreases the cost of production expected to result from implementation of emission controls have not been considered. These include labor input and energy input cost decreases. Annualized compliance costs are overstated from a financial income perspective since these costs include a component for earnings or return on investment. In general, the approach followed is a scenario that overstates the negative impact of the emission controls on the financial operations of the petroleum refining industry.

#### 6.4 LIMITATIONS OF THE ECONOMIC MODEL

Several qualifications of the model presented must be made. First, the partial equilibrium model estimated for each of the five petroleum products assumes that a single homogeneous product is sold in a national market. In the actual market, there may be some differentiation of the refined petroleum products sold throughout the country and regional barriers to trade may exist in the petroleum refinery market. Product differentiation and regional barriers to trade would allow firms in the industry to have greater market power. Market power enables firms to have more control over the market price of the product sold and would lessen the impact of emission controls costs on firms in the industry.

Next, an assumption is made in the model that refineries with the highest per unit control cost are marginal in the post-control market. Firms with the highest per unit control costs are assumed to have the highest underlying cost of production. This assumption was necessary due to lack of available information concerning the cost of production on an individual refinery basis.

Additionally, a review of the data indicates refineries that are marginal in the post-control market have per unit control costs that significantly exceed the average. This may be the result of the engineering method used to assign costs to individual refineries. Moreover, the cost allocation methodology assigns all of the control costs to the five petroleum products

of interest. These products represent less than 100 percent (to be exact, 93 percent) of the refined petroleum products produced domestically. It is not possible to assign compliance costs to every petroleum product due to the lack of data on certain products produced in low quantity, so a decision was made to assign all the costs to the five products produced in the greatest quantity.

Finally, some plants may find that the price increase resulting from the regulations make it profitable to expand production. This would occur if a firm found its post-control incremental cost to be less than the post-control market price. Expansion by these firms would result in a smaller decrease in output and increase in price than otherwise would occur. The foregoing list of qualifications tend to overstate the impacts of the proposed emission controls on the market equilibrium price and quantity, revenues, and plant closures.

Estimates of model results are dependent on the price elasticity measures assumed for demand and supply. A sensitivity analysis of the price elasticity of demand reflects minimal changes in the market results with alternative lower and upper bound elasticity measures. (See the *Economic Impact Analysis for the Petroleum Refinery NESHAP (1995)* for details.)

The methodology used to estimate the price elasticity of supply also must be qualified. The elasticity measure does not estimate the supply elasticities for the individual products or directly consider the interrelationships between products. The assumption implicit in use of this supply elasticity estimate is that the elasticities of the individual petroleum products will not differ significantly from the elasticity of the products combined. This does not seem a totally unreasonable assumption since the same factor inputs are used to produce each of the petroleum products. The methodology also does not explicitly consider the cross-price elasticities for the petroleum products. Since these products are joint products, changes in the price of one product will have an effect on the quantity supplied of the other products.

The uncertainty of the supply estimate is acknowledged. It is possible to conduct a sensitivity analysis of the price elasticity supply. Such an analysis would quantify the impact of this assumption on the reported market results. Given the magnitude of market impact results, reasonable variations in the price elasticity of supply are unlikely to alter the model results significantly.

The estimates of the secondary impacts associated with the emission controls are based on changes predicted by the partial equilibrium model. The limitations previously described are applicable to primary and secondary economic impacts. As previously noted, the estimated employment losses do not consider potential employment gains for operating the emission control equipment. It is important to note that the potential job losses predicted by the model are only those directly linked to predicted production losses in the petroleum refining industry. Likewise, the gains or losses in markets indirectly affected by the regulations, such as substitute product markets, complement products markets, or in markets that use petroleum products as inputs have not been considered in this analysis.

The capital availability analysis also has limitations. Some of these limitations have been previously noted. Future baseline performance may not resemble past levels. Future financial performance of the petroleum refining industry will be affected by market considerations other than emission control measures, and these factors are not readily estimated. Additionally, the tools used in the analysis are limited in scope and do not fully describe the financial position of individual firms within the industry but are more reflective of industry averages. Finally, the approach used to estimate the impact of the control costs on the financial ratios tends to overstate the effect of emission control costs on these ratios.

#### 6.5 PRIMARY IMPACT, CAPITAL AVAILABILITY ANALYSIS, AND SECONDARY IMPACT RESULTS

Estimates of the primary economic impacts, secondary impacts, and capital availability consequences associated with the chosen option or preferred alternative are presented. As previously discussed, Alternative 1 requires MACT floor controls on all emission points other than equipment leaks where a choice of controls allowed refineries is less costly. Primary impacts related to control cost associated with Alternative 1 include changes in the market equilibrium price and output levels, changes in the value of shipments or revenues to domestic producers, and plant closures. Secondary impacts relate to labor market, energy market and international trade effects likely to occur as a result of the emission control requirements. The capital availability analysis assesses the ability of affected firms to raise capital, and the impacts of control costs on plant profitability.

#### 6.5.1 *Estimates of Primary Impacts*

The partial equilibrium model is used to analyze the market outcome of the proposed regulation. The purchase of emission control equipment will result in an upward vertical shift in the domestic supply curve for refined petroleum products. The height of the shift is determined by the after-tax cash flow required to offset the per unit increase in production costs. Since the control costs vary for each of the domestic refineries, the post-control supply curve is segmented, or a step function. Underlying production costs for each refinery are unknown; therefore, a worst case scenario has been assumed. The plants with the highest control costs per unit of production are assumed to also have the highest pre-control per unit cost of production. Thus, firms with the highest per unit cost of emission control are assumed to be marginal in the post-control market.

Foreign supply is assumed to have the same price elasticity of supply as domestic supply. The United States had a negative trade balance for each of the refined products in 1992 with the exception of distillate fuel oil that had a slightly positive trade balance of \$1.1 million. Therefore net exports are negative for all products except distillate fuel oil in the baseline model. Foreign and domestic post-control supply are



added together to form the total post-control market supply. The intersection of this post-control supply with market demand will determine the new market equilibrium price and quantity. Post-control domestic output is derived by deducting post-control imports from the post-control output.

Table 6-2 reveals the primary impacts predicted by the partial equilibrium model for Alternative 1. The range of anticipated price increases for the five products vary from \$0.03 to \$0.14 per barrel produced for residual fuel oil and jet fuel, respectively. The percentage price increase for each product is less than 1 percent and they range from 0.26 percent to 0.53 percent.

Production is expected to decrease by 12.5 million barrels per year for all products, an overall decrease in domestic production of 0.24 percent. The estimated annual reductions in production of the individual products range from 0.65 million barrels to 5.67 million barrels for jet fuel and motor gas, respectively. The production percentage decreases range from 0.13 percent to 0.58 percent for jet fuel and residual fuel oil, respectively.

Value of domestic shipments or revenues for domestic producers are expected to increase for the five products approximately \$107 million annually. The predicted changes in revenues for individual products range from an increase of \$56 million in motor gasoline revenues to a decrease in residual fuel revenues of approximately \$12 million annually. The percent changes range from an increase of 0.41 percent in jet fuel to a decrease of 0.26 percent in residual fuel oil revenues. Economic theory predicts that revenue increases are expected to occur when prices are increased for inelastic goods, all other factors held constant. This phenomenon results from the percentage increase in price exceeding the percentage decrease in quantity for goods with inelastic demand. All of the refined petroleum products follow the expected trend except residual fuel oil.

TABLE 6-2. SUMMARY OF PRIMARY IMPACTS

Refined Product	Estimated Impacts		
	Price Increases <sup>1</sup>	Production Decreases <sup>2</sup>	Value of Domestic Shipments <sup>3</sup>
Motor gasoline			
Amount	\$0.09	(5.67)	\$55.63
Percentage	0.29%	(0.22%)	0.07%
Jet fuel			
Amount	\$0.14	(0.65)	\$53.22
Percentage	0.53%	(0.13%)	0.41%
Residual fuel			
Amount	\$0.03	(1.62)	(\$11.92)
Percentage	0.24%	(0.50%)	( 0.26%)
Distillate fuel			
Amount	\$0.08	(2.78)	\$8.06
Percentage	0.29%	(0.26%)	0.03%
LPGs			
Amount	\$0.07	(1.80)	\$2.42
Percentage	0.26%	(0.25%)	0.01%
TOTAL		(12.52)	\$107.41
		(0.24%)	

NOTES: ( ) indicate decreases.

<sup>1</sup>Prices are shown in price per barrel (\$1992).

<sup>2</sup>Annual production quantities are shown in millions of barrels.

<sup>3</sup>Values of domestic shipments are shown in millions of 1992 dollars.

Residual fuel oil has the highest trade deficit of the five products with over 40 percent of domestic demand being imported. The magnitude of residual fuel oil imports causes a decrease in domestic residual fuel oil revenues to occur in the post-control market.

It is anticipated that between 0 and 7 refineries are at risk of closure as a result of the decrease in production predicted by the model, with the actual number likely being closer to 0 than 7. Those refineries with the highest per unit control costs are assumed to be marginal in the post-control market. Refineries that have post-control supply prices that exceed the market equilibrium price are assumed to close. This assumption is consistent with the perfect competition theory that presumes all firms in the industry are price takers. Firms with the highest per unit control costs may not have the highest underlying cost of production. This is an assumption that likely overstates the the likely number of plant closures and other adverse effects of the emission controls.

The estimated primary impacts reported depend on the set of parameters used in the partial equilibrium model. One of the parameters, the price elasticity of demand, consisted of a range for four of the five refined products. The midpoint of the range of elasticities was used to estimate the reported primary and secondary impacts. A sensitivity analysis of this assumption was conducted. The low and high end of the range of elasticities are inputs in the sensitivity analysis. In general, the sensitivity analysis shows that the estimated primary impacts are relatively insensitive to reasonable changes of price elasticity of demand estimates. Estimates of market impacts with lower elasticity measures shift relatively more of the burden of the emission controls to consumers in the form of slightly higher price increases and lower output decreases. Higher elasticity measures shift more of the burden to producers in the form of slightly lower price increases and higher output decreases.

#### 6.5.2 *Capital Availability Analysis*

The capital availability analysis involves examining pre- and post-control values of selected financial ratios. These ratios

include rate of return on investment, times interest earned coverage ratio, and the debt-equity ratio. Data were not available to estimate the ratios for many refineries in the industry. Consequently, these ratios have been analyzed on an industrywide basis. Since the industrywide ratios represent an average for the industry, individual firms within the industry may have financial ratios that differ significantly from the average. Net income was averaged for a five year period (1986 through 1990) to avoid annual fluctuations in income that may occur due to changes in the business cycle. Debt and equity capital are not subject to annual fluctuations; therefore, the most recent data available (1990) were used in the analysis.

The financial statistics provide insight regarding firms' ability to raise capital to finance the investment in emission control equipment. Table 6-3 shows the estimated impact on financial ratios for the industry.

TABLE 6-3. ANALYSIS OF FINANCIAL RATIOS

Financial Ratios	Pre-Control Ratios	Post-Control Ratios
Rate of return on investment	5.91%	5.91%
Coverage Ratio (or Times Interest Earned)	7.08	7.07
Debt-Equity Ratio	62.75%	62.76%

The financial ratios remain virtually unchanged as a result of the proposed emission controls. The magnitude of the income changes and the capital expenditures necessary for the emission control measures do not significantly alter the financial position of the industry. The impact of the standards on individual refineries, however, may vary greatly from the industry averages used in this analysis.

### 6.5.3 Labor Market Impacts and Energy Market Impacts

The estimated labor impacts associated with the NESHAP are based on the results of the partial equilibrium analyses of the five refined petroleum products and are reported in Table 6-4. The number of workers employed by firms in SIC 2911 is estimated to decrease by approximately 0 to 114 workers as a result of the proposed emission controls, using the assumptions made in the economic analysis with regard to the behavior of per-unit cost. The loss in number of workers depends primarily on the estimated reduction in production. Gains in employment anticipated to result from operation and maintenance of control equipment and from additional monitoring, recordkeeping, and reporting requirements have not been included in the analysis are not considered in the labor impact estimate. Estimates of employment losses do not consider potential employment gains in industries that produce substitute products. Similarly, losses in employment in industries that use petroleum products as an input or in industries that provide complement goods are not considered. The changes in employment reflected in this analysis are only direct employment losses due to reductions in domestic production of refined petroleum products.

The loss in employment annually is relatively low compared to the total employment in the industry (a 0.16 percent loss at most). The magnitude of predicted job losses is a direct results of from the relatively small decrease in production estimated by the model, and by the relatively low labor intensity in the industry. If the gains from employment could have been considered in the analysis, then the predicted loss in employment would be less.

The method used to estimate reductions in use of energy inputs relates the energy expenditures to the level of production. An estimated decrease in energy input use of nearly \$11 million annually is expected for the industry. The individual product energy use changes are reported in Table 6-4. As production decreases, the amount of energy input utilized by the refining industry also declines. The changes in energy use do not reflect the increased energy use associated with operating and

maintaining emission control equipment. Insufficient data were available to consider such changes in energy costs.

TABLE 6-4. SUMMARY OF SECONDARY REGULATORY IMPACTS

Refined Product	Estimated Impacts	
	Labor Input <sup>1</sup>	Energy Input <sup>2</sup>
Motor gasoline		
Amount	(52)	(\$5.79)
Percentage	(0.22%)	(0.22%)
Jet fuel		
Amount	(6)	(\$0.52)
Percentage	(0.13%)	(0.13%)
Residual fuel		
Amount	(15)	(\$0.71)
Percentage	(0.50%)	(0.50%)
Distillate fuel		
Amount	(25)	(\$2.27)
Percentage	(0.26%)	(0.26%)
LPGs		
Amount	(16)	(\$1.56)
Percentage	(0.25%)	(0.25%)
Total five products		
Amount	(0-114)	(0-\$10.85)
	(0-0.16%)	

NOTES: ( ) Indicates decreases.

<sup>1</sup>Indicates estimated reduction in number of jobs.

<sup>2</sup>Reduction in energy use in millions of 1992 dollars.

#### 6.5.4 Foreign Trade Impacts

The implementation of the NESHAP will increase the cost of production for domestic refineries relative to foreign refineries, all other factors being equal. This change in the relative price of imports will cause domestic imports of refined petroleum products to increase and domestic exports to decrease. The balance of trade overall for refined petroleum products is currently negative (imports exceed exports). The NESHAP will likely cause the trade deficit to increase. Net exports are likely to decline by 2.3 million barrels per year, a 1.2 percent decline. The range of net export decreases vary from 0.21 million barrels to 0.91 million barrels for LPGs and residual fuel oil, respectively. The related percent decreases range from 0.54 percent to 40.9 percent for LPGs and distillate fuel oil, respectively. The large percentage decrease in exports of distillate is the result of the product having a very small positive trade balance in the pre-control market. The dollar value of the total decline in net exports is expected to amount to \$68.2 million annually. The predicted changes in the trade balance are reported in Table 6-5.

#### 6.5.5 Regional Impacts

No significant regional impacts are expected from implementation of the NESHAP. Between 0 and 7 refineries are estimated to close nationwide, with the point estimate likely closer to 0 than 7. Due to the manner used to estimate control costs for the individual refinery and the method of allocating the costs to products, the facilities predicted to close do not necessarily represent the facilities most likely to close. However, the facilities postulated in the model are dispersed throughout the United States and are not specific to a particular geographical region. Employment impacts are directly related to plant closure and production decreases. Employment impacts are also dispersed throughout the country.

#### 6.6 SUMMARY

The estimated market changes resulting from the proposed emission controls are relatively small. Predicted price increases and reductions in domestic output are less than 1



percent for each of the refined products. The value of domestic shipments or revenues to domestic producers are anticipated to increase for the 5 product categories by a total of \$107 million annually (\$1992). Emission controls costs are small relative to the financial resources of affected producers, and on average, refineries should not find it difficult to raise the capital necessary to finance the purchase and installation of emission controls. The economic analysis estimates that between 0 and 7 refineries may close as a result of the emission controls, with the point estimate of the range likely being closer to 0 than 7.

As to the estimated secondary economic impacts, between 0 and 114 job losses may occur nationwide, given the effects on labor that are considered in the analysis. Energy input reductions are estimated to be approximately \$11 million annually. A decrease in net exports of 2.3 million barrels, a decrease of 1.24 percent, annually in refined products is anticipated to occur. No regional impacts are expected.

TABLE 6-5. FOREIGN TRADE (NET EXPORTS) IMPACTS

Refined Product	Estimated Impacts		
	Amount <sup>1</sup>	Percentage	Dollar Value of Net Export Change <sup>2</sup>
Motor Gasoline	(0.43)	(0.54%)	(\$21.92)
Jet fuel	(0.23)	(1.41%)	(\$8.14)
Residual fuel	(0.91)	(0.81%)	(\$16.81)
Distillate fuel	(0.48)	(40.92%)	(\$12.67)
LPGs	(0.21)	(0.54%)	(\$8.68)
Total	(2.26)	(1.24%)	(\$68.22)

NOTES: ( ) indicates decreases.  
<sup>1</sup>Millions of barrels.  
<sup>2</sup>Millions of dollars (\$1992).

## 6.7 POTENTIAL SMALL BUSINESS IMPACTS

### 6.7.1 Introduction

The Regulatory Flexibility Act (RFA) of 1980 and EPA Guidelines for Regulatory Flexibility Analyses (1992) require that special consideration be given to the effects of all proposed regulations on small business entities. The Act requires that a determination be made as to whether the subject regulation will have a significant impact on a substantial number of small entities; the Guidelines require that a final Regulatory Flexibility Analysis be done if **any** impact on small entities occurs. The analysis used four criteria provided in the original Federal Guidelines for Regulatory Flexibility Analyses (1982). A substantial number is considered to be greater than 20 percent of the small entities identified. The following criteria are provided for assessing whether impacts are significant. The impact on small business entities is considered significant whenever any of the following criteria are met:

1. annual compliance costs (annualized capital, operating, reporting, etc.) increase as a percentage of cost of production for small entities for the relevant process or product by more than 5 percent;
2. compliance costs as a percent of sales for small entities are at least 10 percent higher than compliance costs as a percent of sales for large entities;
3. capital costs of compliance represent a significant portion of capital available to small entities, considering internal cash flow plus external financing capabilities; and
4. the requirements of the regulation are likely to result in closure of small entities.

### 6.7.2 Methodology

Data are not readily available to estimate the small business impacts for two of the criteria (1 and 3) listed in the previous section. The information necessary to make such comparisons are generally considered proprietary by small business firms. Consequently, the analysis will focus on remaining two (2 and 4) criteria of the potential for adverse impacts. Closure of small businesses and a comparison of the compliance costs as a percentage of sales for small and large business entities will be examined.

The closure method of analysis will focus on the number of petroleum refineries expected to close as a result of the emission controls and the relative size of the firms at risk. Alternatively, a measure of annual compliance costs as a percentage of sales will also be considered. The ratio of costs to sales will be compared for small refineries to the same ratio for all other refineries.

### 6.7.3 Categorization of Small Businesses

Consistent with Title IV, Section 410 of the CAA, a petroleum refinery firm is classified as a small business if it has less than 1,500 employees or has annual production less than 50,000 barrels produced per day. A firm must also be unaffiliated with another large business entity to be classified as small. Information necessary to distinguish refinery size by number of employees was not readily available. However, daily production data were available from the *Oil and Gas Journal, U.S. Refinery Survey* (1-1-92). Based upon the production size criterion, there were 63 operating refineries in 1992 that could be categorized as small business entities.

### 6.7.4 Small Business Impacts

The results of the partial equilibrium analysis lead to the conclusion that between 0 and 7 refineries are at risk of closure, with the actual number likely closer to 0 than 7. The upper end of the estimate represents approximately four percent of the domestic refineries in operation and 11 percent of those designated to be small businesses. The estimated number of

closures is therefore less than 20 percent of the small refineries. However, it is important to note that the firms designated in the model as being at the greatest risk for closure were small refineries.

Compliance costs as a percentage of sales were computed both for the small refineries and for those refineries that are not considered small. The cost to sales ratio for the small refineries was 0.19 percent of sales while the cost to sales ratio for all other refineries was 0.08 percent. The differential between these two rates exceeds ten percent, and consequently, a conclusion is drawn that a significant number of small businesses are adversely affected by the promulgated regulations.

#### 6.8 SOCIAL COSTS OF REGULATION

The social costs of regulation are those costs borne by society for pollution abatement. From an economic perspective, the social costs of regulation represent the opportunity costs of scarce resources utilized for pollution control, or the economic costs. Scarce resources used in pollution control could alternatively be used by society for purposes other than emission control. Thus, a social loss or economic cost occurs. Consumers, producers, and all of society bear the costs of pollution controls. Economic losses to consumers result from the higher prices paid for goods consumed and the lesser quantity goods consumed. Producers benefit from a higher price paid by consumers for each unit of product sold but incur compliance costs for each unit of production. Producers also sell a smaller quantity of the good after controls are implemented. Finally, it is necessary to adjust the preceding changes in consumer and producer surplus to reflect the regulation's cost to society. The change in residual surplus represent tax revenues that may be gained or lost from the emission controls and the differential in the private cost of capital and the social cost of capital. The economic costs of regulation ( $EC$ ) as previously defined consists of the sum of the change in domestic consumer surplus ( $\Delta CS_d$ ), the change in producer surplus ( $\Delta PS$ ), and the change in the

residual surplus to society ( $\Delta RS$ ) resulting from the emission controls.

#### 6.8.1 Social Cost Estimates

The components of the social costs of regulation have been previously discussed. More details on the exact methodology for calculating for these values are contained in the *Economic Impact for the Petroleum Refinery NESHAP* (1995). The economic costs of Alternative 1 (the set of chosen alternatives) are displayed in Table 6-6. The social costs of Alternative 1 are estimated from the partial equilibrium model and are divided into changes in consumer, producer, and residual surplus.

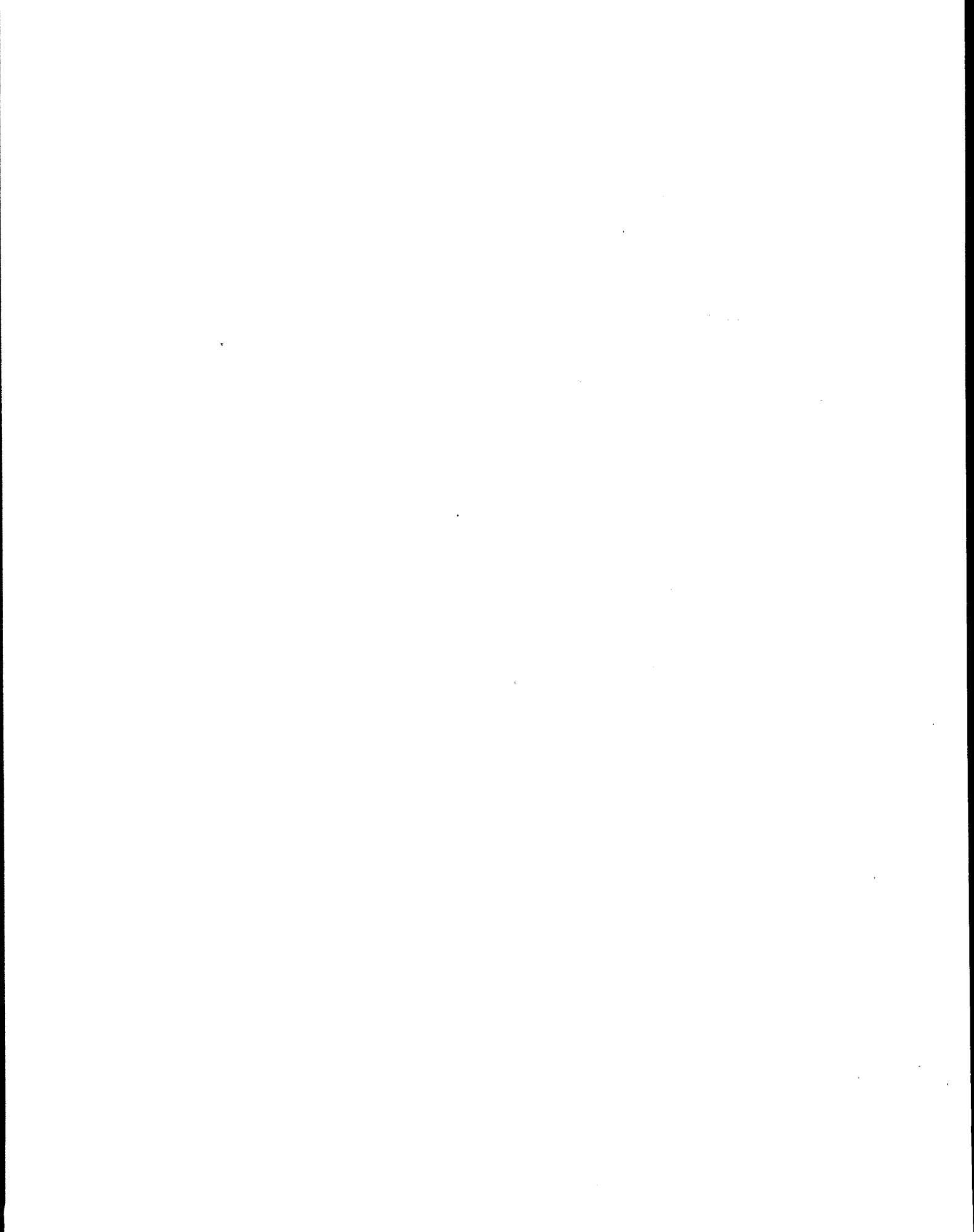
TABLE 6-6. ANNUAL SOCIAL COST ESTIMATES FOR THE PETROLEUM REFINING REGULATION  
(Millions of 1992 dollars)

Social Cost Category	Net Costs <sup>1</sup>
Surplus Costs for Preferred Option:	
Change in Consumer Surplus	\$342.86
Change in Producer Surplus	\$(174.32)
Change in Residual Surplus to Society <sup>2</sup>	\$(73.25)
Total Social Cost of Alternative 1 <sup>3</sup>	\$95.29

NOTES: <sup>1</sup>Brackets indicate negative surplus losses, or surplus gains.

<sup>2</sup>Residual surplus loss to society includes adjustments necessary to equate the relevant discount rate to the social cost of capital and to consider appropriate tax effect adjustments.

<sup>3</sup>Alternative 1 includes floor controls for all emission points except equipment leaks. Option 1 is preferred to the floor for equipment leaks because it is a less costly option than the floor.



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## 7.0 QUALITATIVE ASSESSMENT OF BENEFITS OF EMISSION REDUCTIONS

One rationale for environmental regulation is to provide benefits to society by improving environmental quality. In this chapter, and the two chapters which follow, information is provided on the types and levels of social benefits anticipated from the petroleum refinery NESHAP. This chapter examines the potential health and welfare benefits associated with air emission reductions projected as a result of implementation of the petroleum refinery NESHAP. The final regulation is expected to reduce emissions of HAPs emitted from storage tanks, process vents, equipment leaks, and wastewater emission points at refining sites. Of the HAPs emitted by petroleum refineries, some are classified as VOCs, which are ozone precursors.

In general, the reduction of HAP emissions resulting from promulgation and implementation of the petroleum refinery NESHAP will reduce human and environmental exposure to these pollutants and thus, reduce potential adverse health and welfare effects. This chapter provides a general discussion of the various components of total benefits that may be gained from a reduction in HAPs through the subject NESHAP. HAP benefits are presented separately from the benefits associated specifically with VOC emission reductions.

## 7.1 IDENTIFICATION OF POTENTIAL BENEFIT CATEGORIES

The benefit categories associated with the emission reductions predicted for this regulation can be broadly categorized as those benefits which are attributable to reduced exposure to HAPs, and those attributable to reduced exposure to VOCs. The predicted emissions of a few HAPs associated with this regulation have been classified as probable or known human carcinogens. As a result, one of the benefits of the proposed regulation is a reduction in the risk of cancer mortality. Other benefit categories include: reduced exposure to noncarcinogenic HAPs, and reduced exposure to VOCs. In addition to health impacts occurring as a result of reductions in HAP and VOC emissions, there are welfare impacts which can also be identified. In general, welfare impacts include effects on crops and other plant life, materials damage, soiling, and visibility. Each category is discussed separately in the following section.

## 7.2 QUALITATIVE DESCRIPTION OF AIR RELATED BENEFITS

A summary of the range of potential physical health and welfare effects categories that may be associated with HAP emissions and also with concentrations of ozone formed by VOC HAPs is provided in Table 7-1. As noted in the table, exposure to HAPs can lead to a variety of acute and chronic health impacts as well as welfare impacts. The health and welfare benefits of HAP and VOC reductions are presented separately.

### 7.2.1 *Benefits of Decreasing HAP Emissions*

Human exposure to HAPs may occur directly through inhalation or indirectly through ingestion of food or water contaminated by HAPs or through dermal exposure. HAPs may also enter terrestrial and aquatic ecosystems through atmospheric deposition. HAPs can be deposited on vegetation and soil through wet or dry deposition. HAPs may also enter the aquatic environment from the atmosphere via gas exchange between surface water and the ambient

air, wet or dry deposition of particulate HAPs and particles to which HAPs adsorb, and wet or dry deposition to watersheds with subsequent leaching or runoff to bodies of water.<sup>1</sup> This analysis is focused only on the air quality benefits of HAP reduction.

7.2.1.1 *Health Benefits of Reduction in HAP Emissions.*

According to baseline emission estimates, this source category currently emits approximately 81,000 Mg of HAPs annually. The petroleum refinery NESHAP will regulate several of the 189 air toxics listed in Section 112(b) of the CAA. Exposure to ambient concentrations of these pollutants may result in a variety of adverse health effects considering both cancer and noncancer endpoints.

TABLE 7-1. POTENTIAL HEALTH AND WELFARE EFFECTS ASSOCIATED WITH EXPOSURE TO HAZARDOUS AIR POLLUTANTS<sup>2</sup>

Effect Type	Effect Category	Effect End-Point	Citation
Health	Mortality	Carcinogenicity	EPA (1990) <sup>3</sup> , Graham <u>et al.</u> (1989) <sup>4</sup>
		Genotoxicity	Graham <u>et al.</u> (1989) <sup>5</sup>
		Non-Cancer lethality	Voorhees <u>et al.</u> (1989) <sup>6</sup>
Chronic Morbidity		Neurotoxicity	All morbidity end-points obtained from Graham <u>et al.</u> (1989) <sup>7</sup>
		Immunotoxicity	Voorhees <u>et al.</u> (1989) <sup>7</sup>
		Pulmonary function decrement	Cote <u>et al.</u> (1988) <sup>8</sup>
		Liver damage	(1988) <sup>9</sup>
		Gastrointestinal toxicity	
		Kidney damage	
		Cardiovascular impairment	
		Hematopoietic (Blood disorders)	
		Reproductive/Developmental toxicity	
Acute Morbidity		Pulmonary function decrement	
		Dermal irritation	
		Eye irritation	

Welfare	Materials	Corrosion/Deterioration	NAS (1975) <sup>10</sup>
	Damage		
	Aesthetic	Unpleasant odors	
		Transportation safety concerns	
	Agriculture	Yield reductions/Foliar injury	Stern <u>et al.</u> (1973) <sup>11</sup>
	Ecosystem	Biomass decrease	
	Structure	Species richness decline	Weinstein and Birk (1989) <sup>12</sup>
		Species diversity decline	
		Community size decrease	
		Organism lifespan decrease	
		Trophic web shortening	

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Many HAPs are classified as known human carcinogens. Speciation of the HAP emissions at refining sites was available only for equipment leaks. Of those HAPs (presented in Table 3-2), only benzene is classified as known human carcinogens, according to an EPA system for classifying chemicals by cancer risk. This means that there is sufficient evidence to support that exposure to this chemical causes an increased risk of cancer in humans. Benzene is a concern to EPA because long term exposure to this chemical has been known to cause leukemia in humans. While this is the most well known effect, benzene exposure is also associated with aplastic anemia, multiple myeloma, lymphomas, pancytopenia, chromosomal breakages, and weakening of bone marrow.<sup>13</sup> Therefore, a reduction in human exposure to benzene could lead to a decrease in cancer risk and ultimately to a decrease in cancer mortality.

Cresols are considered to be group C or possible human carcinogens. For these HAPs, there are limited data on animal carcinogenicity, but no data on human carcinogenicity. Data are currently inadequate to quantitatively estimate possible cancer risks associated with cresol exposure.

The remaining HAPs emitted by equipment leaks at refining sites have not been shown to cause cancer. However, exposure to these pollutants may still result in adverse health impacts to human and non-human populations. Noncancer health effects can be grouped into the following broad categories: genotoxicity, developmental toxicity, reproductive toxicity, systemic toxicity, and irritation. Genotoxicity is a broad term that usually refers to a chemical that has the ability to damage DNA or the chromosomes. Developmental toxicity refers to adverse effects on a developing organism that may result from exposure prior to conception, during prenatal development, or postnatally to the time of sexual maturation. Adverse developmental effects may be detected at any point in the life span of the organism. Reproductive toxicity refers to the harmful effects of HAP exposure on fertility, gestation, or offspring, caused by exposure of either parent to a substance. Systemic toxicity affects a portion of the body other than the site of entry.

Irritation, for the purpose of this document, refers to any effect which results in irritation of the eyes, skin, and respiratory tract.<sup>14</sup>

There are particular noncancer effects in humans associated with exposure to several of these HAPs. Brief exposure to HCl can cause ulceration of the respiratory tract; brief exposure to phenol can cause mortality; and brief exposure to HF can cause severe respiratory damage. n-hexane can cause polyneuropathy (muscle weakness, numbness), and naphthalene's noncancer effects include cataracts and anemia in humans.

For the HAPs covered by the petroleum refinery NESHAP, evidence on the potential toxicity of the pollutants varies. Given sufficient exposure conditions, each of these HAPs has the potential to elicit adverse health or environmental effects in the exposed populations. It can be expected that emission reductions achieved through the subject NESHAP will decrease the incidence of these adverse health effects.

7.2.1.2 *Welfare Benefits of Reduction in HAP Emissions.* The welfare effects of exposure to HAPs have received less attention from analysts than the health effects. However, this situation is changing, especially with respect to the effects of toxic substances on ecosystems. Over the past ten years, ecotoxicologists have started to build models of ecological systems which focus on interrelationships in function, the dynamics of stress, and the adaptive potential for recovery. This perspective is reflected in Table 7-1 where the end-points associated with ecosystem functions describe structural attributes rather than species specific responses to HAP exposure. This is consistent with the observation that chronic sub-lethal exposures may affect the normal functioning of individual species in ways that make it less than competitive and therefore more susceptible to a variety of factors including disease, insect attack, and decreases in habitat quality.<sup>15</sup> All of these factors may contribute to an overall change in the structure (i.e., composition) and function of the ecosystem.

The adverse, non-human biological effects of HAP emissions include ecosystem and recreational and commercial fishery impacts. Atmospheric deposition of HAPs directly to land may affect terrestrial ecosystems. Atmospheric deposition of HAPs also contributes to adverse aquatic ecosystem effects. This not only has adverse implications for individual wildlife species and ecosystems as a whole, but also the humans who may ingest contaminated fish and waterfowl. In general, HAP emission reductions achieved through the petroleum refinery NESHAP should reduce the associated adverse environmental impacts.

#### *7.2.2 Benefits of Reduced VOC Emissions*

Emissions of VOCs have been associated with a variety of health and welfare impacts. VOC emissions, together with  $\text{NO}_x$ , are precursors to the formation of tropospheric ozone. It is exposure to ambient ozone that is most directly responsible for a series of respiratory related adverse impacts. Consequently, reductions in the emissions of VOCs will also lead to reductions in the types of health and welfare impacts that are associated with elevated concentrations of ozone. In this section, the benefits of reducing VOC emissions are examined in terms of reductions in ozone.

*7.2.2.1 Health Benefits of Reduction in VOC Emissions.* Human exposure to elevated concentrations of ozone primarily results in respiratory-related impacts such as coughing and difficulty in breathing. Eye irritation is another frequently observed effect. These acute effects are generally short-term and reversible. Nevertheless, a reduction in the severity or scope of such impacts may have significant economic value.

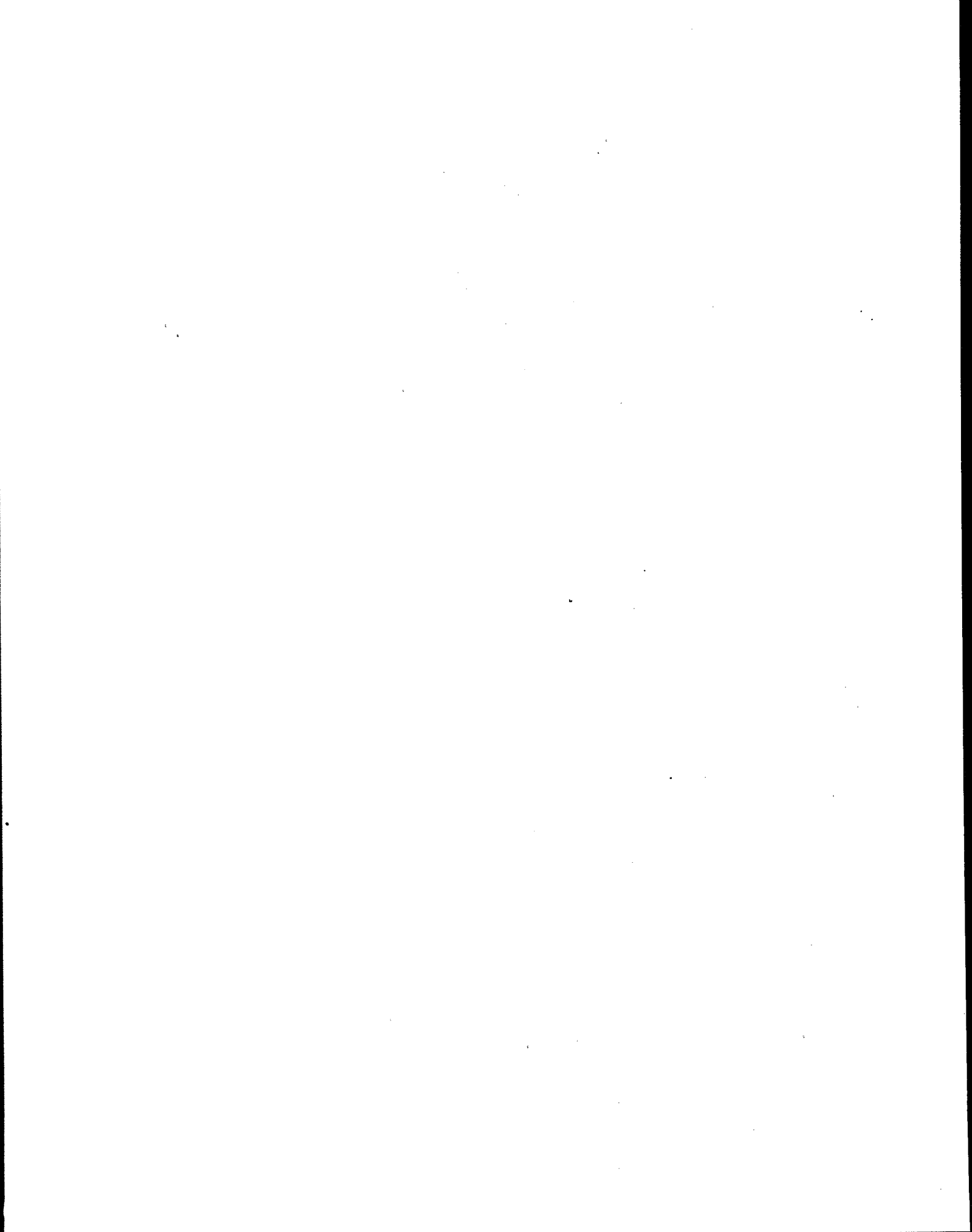
Recent studies have found that repeated exposure to elevated concentrations of ozone over long periods of time may also lead to chronic, structural damage to the lungs.<sup>16</sup> To the extent that these findings are verified, the potential scope of benefits



related to reductions in ozone concentrations could be expanded significantly.

Major ozone health effects are: alterations in lung capacity and breathing frequency; eye, nose and throat irritation; reduced exercise performance; malaise and nausea; increased sensitivity of airways; aggravation of existing respiratory disease; decreased sensitivity to respiratory infection; and extrapulmonary effects (central nervous system, liver, cardiovascular, and reproductive effects).<sup>17</sup> In general, it is expected that reductions in VOCs through the petroleum refinery NESHAP regulation is a mechanism by which the ambient ozone concentration may be reduced and, in turn, reduce the incidence of the adverse health effects of ozone exposure. In this section, the benefits of reducing VOC emissions is examined in terms of reductions in ozone.

7.2.2.2 *Welfare Benefits of VOC Reduction.* In addition to acute and chronic health impacts of ozone exposure, there are adverse welfare effects. The principal welfare impact is related to losses in economic value for certain agricultural crops and ornamental plants. Over the last decade, a series of field experiments has demonstrated a positive statistical association between ozone exposure and reductions in yield as well as visible injury to several economically valuable cash crops, including soybeans and cotton. Damage to selected timber species has also been associated with exposure to ozone. The observed impacts range from foliar injury to reduced growth rates and premature death. Benefits of reduced ozone concentrations include both the value of avoided losses in commercially valuable timber and aesthetic losses suffered by non-consumptive users.



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## 8.0 QUANTITATIVE ASSESSMENT OF BENEFITS

This chapter presents quantitative estimates of the possible dollar magnitude of the benefits identified in the previous chapter. The quantification of dollar benefits for all benefit categories is not possible at this time because of limitations in both data and methodology. This chapter presents the methodology which was utilized to obtain monetary estimates of HAP and VOC emission reductions occurring as a result of the proposed rule. Limitations of this methodology are also identified. To ensure that an economically efficient regulatory alternative is chosen, an incremental analysis must be performed. Therefore, benefits for the two regulatory alternatives are presented. Potential impacts are evaluated for the promulgated regulation and one alternative more stringent than that.

### 8.1 METHODOLOGY FOR DEVELOPMENT OF BENEFIT ESTIMATE

Quantification of impacts associated with HAP exposure requires information on the particular HAP involved. Such data are necessary because different HAP emissions can lead to different types and degrees of severity of impacts. Table 8-1 identifies the specific HAPs emitted by petroleum refineries. Although an estimate of the total reduction in HAP emissions for various control options has been developed for this RIA, it has not been possible to estimate specific HAP emission reductions for each type of emission point. However, an estimate of HAP speciation for equipment leaks has been made. Since HAP emissions from equipment leaks account for nearly two thirds of total HAP emissions at petroleum refineries, it is possible to use these data to develop an estimate of cancer risk related to petroleum refinery emissions.

The potential impacts of reducing HAP emissions can be separated into two health benefits categories. The first health benefit category evaluated will be the reduction in annual cancer incidence due to carcinogenic HAP emission reductions. This

approach uses emissions data and the Human Exposure Model (HEM) to estimate the annual cancer risk caused by HAP emissions from petroleum refineries. Generally, this benefit category is calculated as the difference in estimated annual cancer incidence before and after implementation of each regulatory alternative. The benefit category is then monetized by applying a range of benefit values for each cancer case avoided.

The second category of health benefits expected to result from reduced HAP emissions is reduced human exposure to noncarcinogenic HAP emissions. For each noncarcinogenic HAP for which EPA had health benchmark information, EPA performed a baseline assessment to estimate the number of people exposed to HAPs above health benchmark levels. The quantified benefits attributable to reducing noncarcinogenic HAP emissions is the difference in the number of people exposed above health benchmark levels before and after regulation. The benefits of controlling VOC emissions are monetized by applying average benefit per Megagram estimates to the total amount of VOC emission reductions calculated for each of the two regulatory alternatives.

#### 8.1.1 *Benefits of Reduced Cancer Risk Associated with HAP Reductions*

The proposed MACT for petroleum refineries is expected to reduce the emissions of several HAPs that have been classified as probable or known human carcinogens. As a result, one of the benefits of the final regulation is a reduction in the risk of cancer mortality.

TABLE 8-1. HAP EMISSIONS AT PETROLEUM REFINERIES

2,2,4 - Trimethyl Pentane	Phenol
Benzene	Cresols/Cresylic Acid
Ethylbenzene	Methyl Tertiary Butyl Ether
Hexane	Methyl Ethyl Ketone
Naphthalene	Toluene
Xylenes	

A quantitative assessment of these benefits requires two types of data. First, it must be possible to relate changes in emissions to changes in risk and incidence of cancer. This involves the completion of a risk assessment. The second type of data required to estimate the economic benefits of reduced cancer risk is an estimate of society's willingness to pay to realize this risk reduction. While straightforward in concept, there are difficulties in the way both types of data are usually developed so that the credibility of any quantitative estimates must be carefully assessed. The next two sections discuss the models of cancer risk, and estimates of the value of a statistical life.

8.1.1.1 *Models of Cancer Risk.* A variety of models have been proposed to formalize the relationships between emission changes and changes in cancer risk so that predictions can be made regarding changes in the expected number of lives saved due to a specific emission reduction scenario. Cancer risk models often express cancer risk in terms of excess lifetime cancer risk. Lifetime risk is a measure of the probability that an individual will develop cancer as a result of exposure to an air pollutant over a lifetime of 70 years.<sup>1</sup> A basis for developing estimates of this probability is the unit risk factor (URF). The URF is a quantitative estimate of the carcinogenic potency of a pollutant. It is often expressed as the probability of contracting cancer from a 70 year lifetime continuous exposure to a concentration of one microgram per cubic meter ( $\mu\text{g}/\text{m}^3$ ) of a pollutant. The unit risk factors are designed to be conservative. That is, actual risk may be higher, but it is more likely to be lower. EPA has developed unit risk factors for many HAPs. <sup>1</sup> Among the HAPs identified in Table 8-1, only benzene has a quantitative URFs. In addition, benzene is a known human carcinogen, as there are several studies linking benzene exposure to cancer in humans. Cresols are considered possible human carcinogens based on animal experiments.

To translate lifetime individual risk to annual incidence of excess cancer, it is necessary to combine three pieces of data: the unit risk factor, the (constant) level of concentration to

which the population is exposed, and the population count. For example, benzene, which is classified as a known human carcinogen, has a unit risk factor of  $8.3 \times 10^{-6} (\mu\text{g}/\text{m}^3)^{-1}$ . In a population of 1,000,000 people, each exposed to  $5 \mu\text{g}/\text{m}^3$  of benzene for 70 years (a lifetime of constant exposure), the number of excess cancer cases in the population due to this exposure is estimated to be 41.5 cancer cases over 70 years ( $5 \mu\text{g}/\text{m}^3 \times 1,000,000 \times 8.3 \times 10^{-6} (\mu\text{g}/\text{m}^3)^{-1}$ ). On an annual average basis, this is equal to 0.59 excess cases per year in the population.

From the above example calculation, it is clear that each element in the calculation algorithm may contribute to uncertainty in the final estimate of cancer risk. Table 8-2 summarizes the major sources of uncertainty with the data and methods used in the standard approach to cancer risk assessment. Additional issues arise in estimating economic benefits from the risk assessment information. Table 8-3 identifies these issues.

8.1.1.2 *Value of a Statistical Life.* Economists have used labor market data to identify the wage-risk tradeoff accepted by workers in high risk occupations and to infer the implicit value of reduction in small risks of mortality. This is mathematically equivalent to valuing a small reduction in risk of mortality per person over a large number of people (usually one million people). Multiplication of the value of a statistical life times the expected number of lives saved due to the reduced cancer risk provides an estimate of the economic benefits associated with the regulation. Estimates of the value of a statistical life have been developed by examining the wage-risk tradeoff revealed by workers accepting jobs with known risks. Viscusi recently completed a survey of over 20 of these studies and recommends an initial range of \$3-\$7 million (December 1990 dollars) as an estimate of the statistical value of a life.<sup>2</sup>

Using this range in an environmental policy analysis requires consideration of several factors that could bias the transfer of the results. Specifically, adjustments may be required to



account for differences across applications. These differences include:

- Risk perception: Environmental risks are involuntary; job risks may not be. Cancer risks may be prolonged and involve suffering; job fatalities may be more immediate in consequence.
- Age: The age of the affected population may affect willingness to pay values. Life years saved may be a more relevant measure. Discount rates may also be age-sensitive.
- Income: Income levels of exposed individuals may affect willingness to pay. Economic theory would suggest a positive elasticity between income and risk reduction.
- Baseline risks: The willingness to pay function could be non-linear. Initial risk levels and the change in risk would become important with non-linearities.

TABLE 8-2. SOURCES OF UNCERTAINTY IN CANCER RISK ASSESSMENT<sup>1</sup>

- Unit risk factors are generally derived from a nonthreshold, multi-stage model, which is linear at low doses. Available experimental data are often for high dose exposures so that responses must be extrapolated to the relatively low doses typically associated with ambient conditions.
- Unit risk information is frequently generated from bioassays in which the potency of a chemical is often determined by the effect of the chemical on animals. Transfer of results across species is subject to considerable uncertainty.
- Risk estimates are calculated as if exposed individuals experience a constant outdoor exposure over a lifetime. This ignores activity patterns of people and the opportunity for behavioral adjustments.
- For carcinogens as well as other toxicants, there is a great deal of individual variability in sensitivity to adverse effects. In some cases, the susceptibility of an individual's reaction to a toxic pollutant may be an order of magnitude of greater than another's. This increases the uncertainty of cancer risk estimates at both the individual and population level.

TABLE 8-3. UNCERTAINTIES IN BENEFIT ANALYSIS

- Benefit calculations should reflect the year-by-year change in cancer incidence following policy implementation. The timing of incidences, including latency periods, should be expressly considered.
- Benefit calculations should reflect changes in concentrations over time related to economic responses to the regulatory action.
- Benefit calculations should reflect any changes to the composition of the affected population and possible behavioral responses to exposure.
- Valuation of cancer incidences should address a variety of issues. These include: discounting, age distribution, non-voluntary nature of risk, risk adverseness of general population, probability of fatality, and treatment costs.

Unfortunately, there is no general consensus on the adjustments that should be made to account for these possible biases in a direct transfer of values. As a result, this study makes no adjustments other than to update the values to first quarter 1992 dollars. With this single change, the value range to be applied to the annual reduction in lives saved from reduced cancer mortality for this standard is \$3-7 million.

8.1.1.3 *Quantitative Results.* Emissions of benzene were input into the HEM to conduct a risk and exposure assessment of baseline HAP emissions. One important input to the HEM was the URF of each pollutant (benzene only, in this case). Benzene's URF is presented in Table 8-4.

Table 8-4. UNIT RISK FACTORS FOR CARCINOGENIC HAPS

HAP	URF (x 10 <sup>6</sup> )
Benzene	8.3

The HEM uses the URF in Table 8-4, along with other information such as refinery emissions, to characterize the risk posed to individuals and the population located within a 50 km radius of each refinery (approximately 83.4 million people). Runs using the HEM showed that 4.5 million people exposed to refinery HAP emissions within a 50 km radius of refineries have an individual risk greater than  $1 * 10^{-6}$ . If the risk from any source in a source category is greater than that, then the source category must be listed on the list of source categories in section 112(b) of the Clean Air Act.

The maximum individual risk (MIR) and annual cancer incidence for benzene are presented in Table 8-5. The MIR expresses the increased risk experienced by the person exposed to the highest predicted concentration of each HAP. The values in Table 8-5 are for emissions at baseline only. The annual cancer incidence is the number of new cancer cases estimated to occur in the exposed

population in a year. As estimated in the HEM, the total annual cancer incidence of the HAP is 0.33 of a statistical life. The benefits of reducing cancer risk resulting from reduced emissions of carcinogenic HAP could not be monetized since values of annual cancer risk after controls were not available. However, if it is assumed that the controls required by the promulgated rule would decrease benzene emissions to zero, then a monetary estimate of the benefit of reducing this HAP could be calculated. The benefit of eliminating the carcinogenic HAP emissions is calculated by multiplying the 0.33 reduction in total annual cancer risk by the midpoint of the range of values of a statistical life (\$3-\$7 million), which is \$5 million. This calculation yields a total monetary benefit of \$1.50 million. This is biased upwards, however, because the petroleum refinery NESHAP will not achieve a 100 percent HAP reduction.

Table 8-5. MAXIMUM INDIVIDUAL RISK AND ANNUAL CANCER INCIDENCE OF CARCINOGENIC HAPs

HAP	MIR	Annual Cancer Incidence
Benzene	$1.8 * 10^{-4}$	0.33

These monetary values should be interpreted carefully due to uncertainties in the derivation of annual incidence numbers, the value of statistical life estimates, and the focus on equipment leak emissions. Because these uncertainties, it is not possible to say whether these values are over- or under- estimates of the true value of cancer risk reduction. At best, the numbers should be viewed as a guide to the possible level of benefits that may be realized.

8.1.1.4 *Other Health and Welfare Impacts of HAPs.* A quantitative assessment of the economic benefits related to these impacts requires information on risk relationships, exposure, and economic value. Unfortunately, such data are generally unavailable. Therefore, it is currently not possible to conduct

a complete quantitative analysis of the benefits associated with HAP emission reductions.

Several intermediate quantitative assessment approaches have been developed which can provide partial objective of the positive impact of HAP emission reductions. One approach examines changes in the population exposed to concentrations of HAPs over a reference dose level with and without additional controls.<sup>3</sup> The reference dose level is designed to reflect a concentration level, with a margin of safety, at which no adverse health impacts would be expected. To complete this calculation, data must be available on population counts near affected refineries, concentrations of speciated HAPs with and without additional controls, and a reference dose level for the specific HAP.

Based on toxicity and emission information, an exposure assessment was performed for hexane, hydrogen chloride, methyl ethyl ketone, and toluene. For noncarcinogens, the dose-response is expressed in terms of an inhalation reference-dose concentration (RfC). Using the RfC methodology, a benchmark concentration is calculated below which adverse effects are not expected to occur. The significance of the RfC benchmark is that exposures to levels below the RfC are considered "safe" because exposures to concentrations of the chemical at or below the RfC have not been linked with any observable health effects. The RfCs of the above mentioned HAPs are presented in Table 8-6. The benefits of reducing these HAPs could not be monetized because information on reduced exposure is not available. The omission of this benefit category from the monetized benefits analysis will lead to an underestimation of the total expected benefits from the promulgated regulation. Only baseline exposure was analyzed.

Table 8-6. RFCS AND NUMBER OF INDIVIDUALS EXPOSED AT OR ABOVE RFC BY HAPS

HAP	RfC (mg/m <sup>3</sup> )	Individuals Exposed At or Above RfC
Hexane	0.2	0
Hydrogen Chloride	0.07	1,810
Methyl Ethyl Ketone	1	0
Toluene	0.4	0

Epidemiological studies that attempt to identify statistical associations between exposure and observable responses in the population represent another way to quantify possible risks. However, because of collinearity with other environmental factors, it is often very difficult to isolate the effects due solely to changes in HAP emissions. For this reason, such statistical functions have generally not been estimated.

At present, most of the model development in the area of estimating the welfare effects and ecosystem impacts of exposure to HAPs is still conceptual and not amenable to objective measurement. Therefore, no quantitative estimates of these potential ecosystem impact have been made.

#### 8.1.2 Quantitative Benefits of VOC Reduction

The benefits of reduced emissions of VOC from a MACT regulation of petroleum refineries will be developed largely using the technique of "benefits transfer." Benefits transfer involves the use of benefit values obtained from another study to represent benefits associated with the promulgated rule, with appropriate adjustments. At a minimum, the adjustments must address the differential impact in the severity of the regulation as represented, for example, by changes in emissions or concentrations. With this technique, the assumption is made that benefits per ton of emission reduction are constant. Then, knowledge of a benefit per ton reduced ratio from a prior study, coupled with information on tons reduced for the regulation under review, will be sufficient to estimate benefits for the current

final regulation. In effect, extrapolated benefits are developed on the basis of a constant, average benefit per ton reduced value.

In this RIA, an estimate of the benefits per metric ton (megagram) reduced of VOC emissions is developed from a study conducted for the Office of Technology Assessment.<sup>4</sup> The OTA study examined a variety of acute health impacts related to ozone exposure as well as the benefits of reduced ozone concentrations for selected crops. However, chronic health effects of ozone exposure were not considered. Therefore, all else equal, the extrapolated estimate of VOC benefits for the MACT regulation should be viewed as a lower bound estimate.

8.1.2.1 *Benefit Transfer Values.* Application of the benefit transfer technique requires information on benefit values and the associated reduction in VOC emissions. Data on benefits are taken from Table 3-10 of the OTA report. For the present calculation, the values reported for the 35 percent VOC reduction scenario are used. Specifically, information from both the epidemiological studies and the clinical studies reported in the OTA report is used to establish an initial benefit range of \$54-3,400 per year per ton VOC emission reduction.

The selection of this range of values was influenced by several factors. First, the results for the 35 percent VOC emission reduction scenario are used because it is easier to identify the level of emission reductions associated with this scenario in the OTA report. It should also be noted that this scenario involves a reduction of 35 percent in those emissions occurring only in nonattainment areas. Although there are expected to be VOC emission reductions in attainment areas under this scenario, the percentage reduction in VOC emissions in attainment areas is less than 35 percent. A close reading of the OTA report indicates that all health impacts are estimated for non-attainment areas only. Therefore, no health benefits are associated with VOC emission reductions in attainment areas, according to the report. This may provide additional conservatism to the benefit values since there is recent evidence



that acute health effects may be experienced at ozone concentrations below the current NAAQS.<sup>5</sup>

The OTA report calculates acute health impacts based on the results of epidemiological and clinical studies. Both study designs have advantages and disadvantages relative to one another. Indeed, the OTA report acknowledges that it is not possible to judge which approach is superior. Even though the two study designs measure similar impacts, it is possible to use the results from both design types to form a range of values. This approach would not involve double-counting and would use more of the available information. A lower bound value is identified from the epidemiological study design. An upper bound value is taken from the clinical study design in which all exercisers are affected. These choices lead to the initial benefit range of \$54-3,400 per ton VOC emission reduction.

The year of dollars for these benefit values is not made clear in the OTA report. However, a check with the authors of several of the cited references used to develop "willingness-to-pay" values, indicates that the values are in 1984 dollar terms.<sup>6</sup> To maintain consistency with other parts of this RIA, the benefit values are converted to first quarter 1992 dollars by multiplying the 1984 dollars by a factor of 1.335. This factor was computed from the percentage change in the all item urban CPI index between the annual index value for 1984 and the geometric mean of index values for the first three months of 1992.<sup>a</sup> The adjusted dollar range in first quarter 1992 dollars is \$72-4,539 per ton VOC emission reduction.

Three further adjustments can be considered for this benefit value range. First, as noted earlier, benefits can be scaled by the tons of VOC emissions reduced in order to form a benefit transfer ratio that can be multiplied by the VOC emission reductions for the petroleum refinery MACT.

Second, the benefit values in the OTA report reflect a level of exposure that corresponds to population densities in nonattainment areas in the early 1980's. Since the cost analysis is conducted for the fifth year following rule promulgation (the year 2000), the benefit analysis should be conformable. There is

approximately a twenty year interval from the period when the estimates used in the OTA report were calculated to the year of regulatory impact. It is appropriate to scale the OTA benefit values by a factor that represents the percentage change in population, between 1980 and 1999, in those nonattainment areas with petroleum refineries as of 1995. Using data from the 1980 and 1990 Censuses and extrapolating to 1999 under an assumption of a constant growth rate equal to that observed for the 10 year period, it is estimated that the population scale factor is 19.64 percent. This leads to a revised benefit value range of \$86 to \$5,430 million.

Third, the passage of time may also affect the willingness to pay value. If real income grows over time and the income elasticity of environmental quality is positive, then unit willingness to pay values in 1999 should exceed those implied by the surveys conducted in the mid-1980's. Using the 1993 Statistical Abstract,<sup>b</sup> the simple average percentage change in per capita real income between 1985 and 1992 is 3.3 percent in those areas most likely to be ozone nonattainment areas. Extrapolating to 1999 under a constant growth assumption results in an increase of 6.7 percent. Given this relatively small change and uncertainty about the proper income elasticity measure, no adjustment has been made to the benefit value range to account for this factor.

It should be noted that even though the population of those in ozone nonattainment areas has fallen since the early 1980's, VOC emissions as precursors to ozone formation have fallen also. Thus, any adjustment to the benefit transfer ratio used in this analysis must take into account the reduction in emissions as well as any changes in air quality that have occurred since the time of the data used in the OTA report. It is uncertain whether the benefit transfer ratio would change significantly with such adjustments.

8.1.2.2 *Agricultural Yield Estimates.* In addition to valuing acute health effects, the OTA report also attempted to value the effect that reduced VOC emissions would have on the yield of crops. Ozone levels currently found in rural areas are

linked with reduced growth rates and yields of crops such as soybeans and oats. Lower VOC concentrations are expected to reduce ambient ozone concentrations, which in turn will increase crop yields. This category of benefits is primarily true for areas, mostly rural, in ozone attainment that have refineries in relative proximity, but it also applies in nonattainment areas as well. The report estimated that an annual reduction of approximately 11 million Mg of VOC would result in total annual agricultural benefits ranging from \$1.4 billion to \$27 billion while an annual reduction of approximately 5.7 million Mg of VOC would result in total annual agricultural benefits of approximately \$77 million to \$1.4 billion. These benefits translate into an average benefit value per Mg of VOC emission reduction of approximately \$120 to \$236 (first quarter 1992 dollars). To calculate the monetized benefits from improved agricultural yields, a point estimate of \$178 per Mg was used and applied to both attainment and nonattainment VOC emission reductions.

8.1.2.3 *Emission Reductions.* The development of VOC emission reductions associated with the benefits range described above can be determined directly from the OTA report. Tables 6-1 and 6-6 of the report provide the needed information. Total VOC emissions in 1985 are 25 million tons.<sup>c</sup> Of this total, 11 million tons are predicted to occur in nonattainment cities while 14 million tons of VOC are predicted to be emitted in ozone attainment areas. For the 35 percent VOC (nonattainment area) emission reduction scenario, 3.8 million tons of VOC emissions are predicted to be controlled in 1994, while 2.7 million tons will be controlled in attainment areas.

The selection of a "tons reduced" value for the denominator of the benefit transfer ratio must be consistent with the benefits measure selected for the numerator. As described earlier, the benefits reflect the annual reduction in acute health impacts experienced by populations in nonattainment areas that result from a 35 percent reduction in nonattainment area VOC emissions. Implicitly, there is the assumption, derived from the OTA study, that no health benefits occur in attainment areas. This also

implies that the derivation of petroleum refinery health benefits from VOC emission reductions should consider only those emission reductions that occur at refineries in nonattainment areas. Fortunately, because individual refineries are identified, it is possible to identify this subset of emission reductions. A result of this approach is that no acute health impacts are associated with VOC emission reductions in attainment areas.<sup>d</sup> Table ES-3 in the executive summary presents the baseline VOC emissions, and the emission reductions for refineries in nonattainment areas associated with each alternative.

One final step is needed prior to forming the benefit transfer ratio. Since VOC emission reductions for petroleum refineries are stated in megagrams per year (metric tons per year), it is necessary to convert the OTA emission reductions to equivalent metric tons. This conversion results in a reduction of 3.45 million metric tons in nonattainment areas.

8.1.2.4 *Benefit Estimates.* The benefit transfer ratio range for acute health impacts is estimated to be \$25-1,574 (first quarter 1992 dollars per megagram or metric ton). These values were obtained by dividing the benefit range values by the reduction in emissions. The average (mid-point) of the range is \$800 per megagram. These ratios are to be multiplied by VOC emission reductions from petroleum refineries located in ozone nonattainment area in order to estimate the VOC-related acute health benefits of the petroleum refinery MACT. Also among the benefits estimates is the estimate of benefits from increased agricultural yields from reduced ozone concentrations, occurring due to VOC emission reductions. Table 8-7 summarizes the results of these calculations for the combination of options selected for the four controlled emission points. Note, the floor option for each emission point type is statutorily mandated so that, in effect, the floor options represent the minimum regulatory requirements.

Table 8-7. QUANTIFIED BENEFITS OF VOC REDUCTIONS BY REGULATORY ALTERNATIVE AND BENEFIT CATEGORY (millions of 1992 dollars)

Alternative 1	
Quantified Acute Health Benefits	
Average	108.48
Range	3.4 - 213.5
Quantified Agricultural Benefits	
Average	44.9
Range	30.3 - 59.5

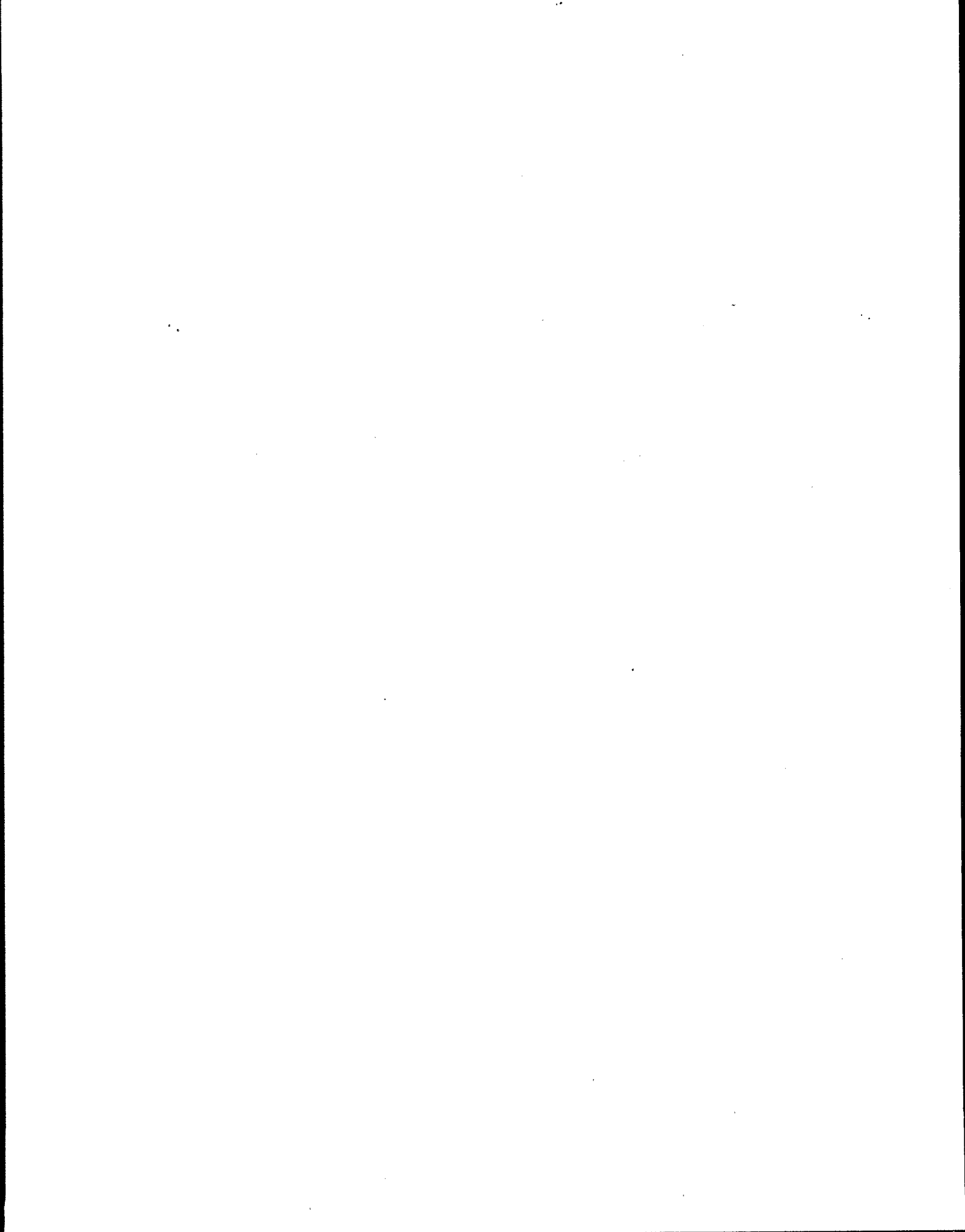
Several qualifications should be noted in interpreted the benefits values above. First, there is an implicit assumption of a constant linear relationship between VOC emission reductions and changes in ozone concentrations in nonattainment areas. Second, as noted earlier, there may be other benefit types. Reductions in VOC emissions that lead to improvements in ozone concentrations may contribute to reductions in chronic health impacts (e.g., sinusitis, hay fever and reduced damage to certain materials, such as elastomers).<sup>8</sup> However, because of data and methodological concerns, no quantitative benefit estimates for these possible effect types have been developed for the present analysis. All else equal, this implies that the calculated benefits per metric ton are likely to be conservative.

Although the quantified VOC benefits estimated in this RIA represent one approach for valuing the benefits of reduced VOC emissions, data limitations prevent a complete quantification of all categories of benefits attributable to VOC reductions. Since lack of data prevent all benefit categories from being monetized, a direct comparison of benefits to costs may not be helpful in determining the desirable regulatory alternative. An assessment of the incremental cost-effectiveness analysis will represent the

cost of the air emissions controls relative to the expected VOC emission reductions attributable to the controls. Because of the lack of data, this analysis ignores the benefit of HAP emission reductions. The incremental VOC cost-effectiveness analysis begins with the baseline, or no control. Alternative 1, the set of alternatives in the promulgated rule, includes controls to meet MACT floor level controls, and a level of control more stringent than the floor for equipment leaks. The annual cost of this control, including equipment costs, MRR costs, and economic costs, is \$94 million annually. This regulatory alternative is expected to result in a reduction of VOC emissions of approximately 134,283 Mg annually in nonattainment areas. Therefore, the incremental cost-effectiveness from baseline, averaged across multiple emission points for nonattainment areas, for alternative 1 is approximately \$714/Mg. In other words, the average cost of reducing each Mg required by alternative 1 is \$714.

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## 9.0 COMPARISON OF BENEFITS TO COSTS

The goal of the RIA (or Economic Assessment) for the Petroleum Refinery NESHAP is to provide economic and some engineering data necessary for effective environmental policy making. A comparison of the benefits of alternative air emission controls with the costs of such controls provides the necessary framework for a reasonable assessment of the net benefits of the proposed environmental resources.

### 9.1 Comparison of Annual Benefits and Costs

The potential health and welfare benefits associated with air emission reductions relate to expected reductions in emissions of several HAPs and VOCs from storage tanks, process vents, equipment leaks, and wastewater emission points at refining sites. The quantification of benefits from emission controls relates to health benefits from reduced cancer incidence associated with carcinogenic HAPs emitted at petroleum refineries and the health benefits related to VOCs that translate into reductions in ozone. Benefits from reducing cancer incidence to zero were quantified for equipment leaks only in the previous chapter. Because of the uncertainty associated with this estimate, the benefits of reduced cancer risk are not incorporated in this benefit cost analysis. Other health and welfare benefits from the controls such as ecosystem benefits have not been quantified due to limitations in data and methodology.

The compliance costs of the regulatory alternatives are taken from the capital costs and operating and maintenance costs for each alternative (including MRR costs) obtained from the cost analysis done by EPA. These estimates reflect engineering costs of emission controls, not the economic costs to society. The compliance costs estimates are a necessary input to the economic analysis using the costs of the regulatory alternatives to society. The economic effect of imposing compliance costs on the petroleum refining markets and its consumers and producers is obtained from a partial equilibrium model of the petroleum

refining industry. The social costs of the controls include potential economic costs to consumers of refined petroleum products, producers of such products, and society as a whole. Economic costs are a better measure of the costs of the air emission control alternative to society because these costs represent the true costs or opportunity costs to society of resources used for emission control. Quantifications of these costs associated with the regulatory alternatives are subject to the limitations noted in Section 6.4, Limitations of the Economic Model.

Costs, both engineering (compliance) and social, for other alternatives other than the chosen ones are not available here due to limitations in resources and data. Table 9-1 depicts a comparison of the benefits of the chosen alternative to the social costs. There is an annual net benefit of \$58.1 million estimated from compliance with the promulgated standard, thus providing some evidence of the desirability of the alternative. A comparison of the net benefits for the alternative and the incremental difference in net benefits between it and other alternatives would be a way to determine if net benefits were at least approaching a maximum. Due to cost information not being available, this comparison cannot be drawn. According to the analyses conducted for this RIA, the standard should provide net benefits to society.

Table 9-1. COMPARISON OF ANNUAL BENEFITS TO COSTS FOR THE NATIONAL PETROLEUM REFINING INDUSTRY NESHAP (MILLIONS OF 1992 \$ PER YEAR)

	Alternative 1
Benefits	\$153.4
Social Costs	\$95.3
Benefits Less Social Costs	\$58.1

NOTES: ( ) represent negative values.

a. CPI index values were obtained from the 1993 U.S. Statistical Abstract (Table 756) and the December 1992 issue of the Survey of Current Business.

b. Statistical Abstract, 1993, Table 704.

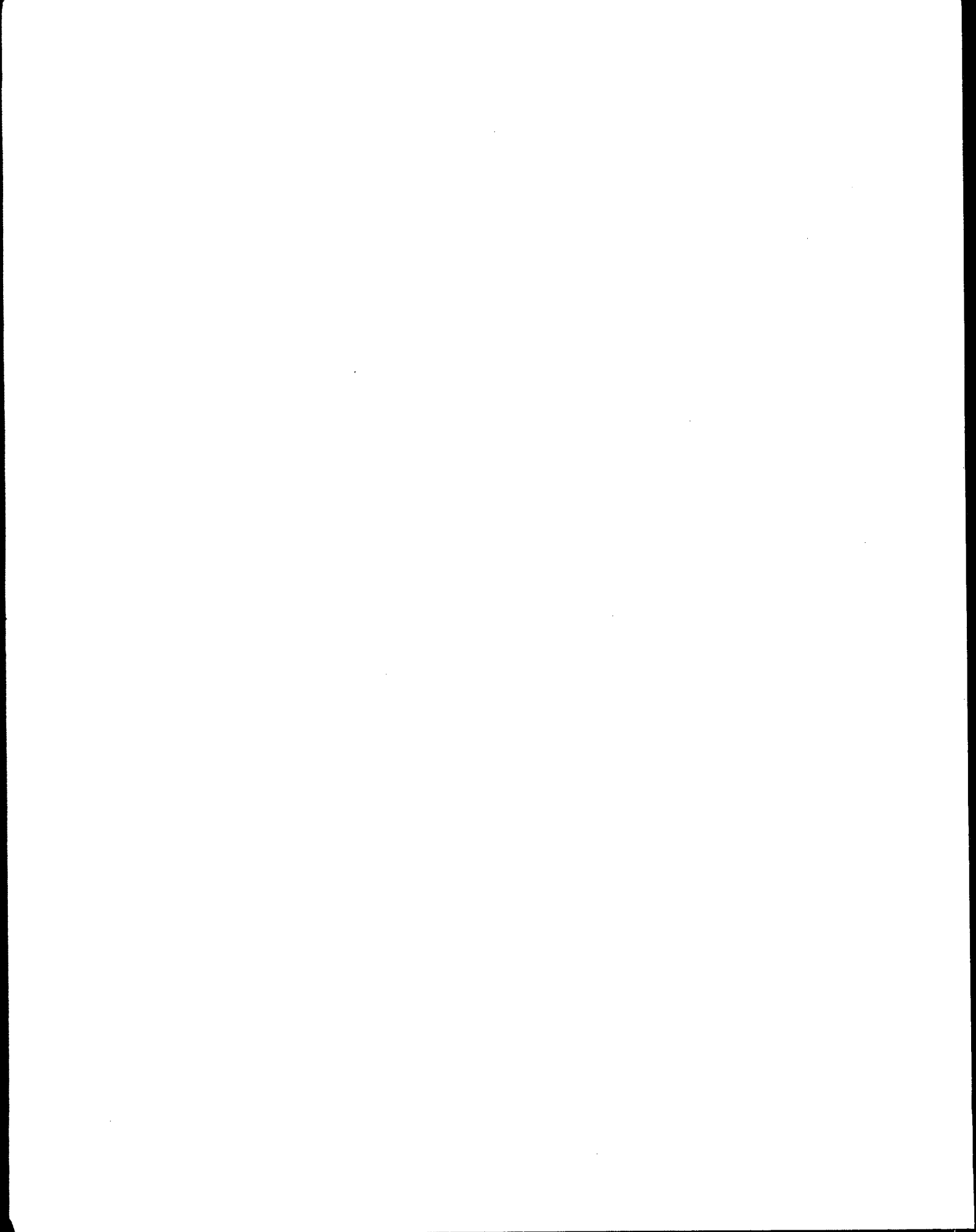
c. The emissions data in OTA do not reflect measured emissions. Rather, they represent emissions on a typical nonattainment day multiplied by 365. It is not clear from the OTA report how these "nonattainment-day-equivalent-annual emissions" are calculated for attainment regions.

d. Recent evidence suggests that some health benefits may occur for VOC emission reductions in areas near, but below, the current ozone NAAQS.<sup>5</sup> As might be expected, the response rate is lower than that observed at higher ozone concentrations. In addition, economic theory suggests that the marginal willingness to pay for increments at a higher level above the standard. That is, the marginal benefits function is non-linear. Since the benefit transfer ratio assumes a constant, linear relationship, it seems prudent to limit the benefit transfer calculation to the nonattainment area data presented in the OTA report.

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*(Please read Instructions on reverse before completing)*

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16. ABSTRACT  An economic analysis of the industries affected by the Petroleum Refineries National Emissions Standard for Hazardous Air Pollutants (NESHAP) was completed in support of this standard. The industry for which economic impacts was computed was the petroleum refinery industry.  Affected refineries must reduce HAP emissions by the level of control required in the standard. Several types of economic impacts, among them product price changes, output changes, job impacts, and effects on foreign trade, were computed for the selected regulatory alternative.				
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