United States Environmental Protection Agency

Office of Air Quality Planning and Standards
Research Triangle Park, NC 27711

FINAL REPORT
EPA-452/R-99-003
May 1999

Air

EPA

ECONOMIC IMPACT ANALYSIS OF THE OIL AND NATURAL GAS PRODUCTION NESHAP AND THE NATURAL GAS TRANSMISSION AND STORAGE NESHAP

Final Report

Economic Impact Analysis of the Oil and Natural Gas Production NESHAP and the Natural Gas Transmission and Storage NESHAP

U.S. Environmental Protection Agency
Office of Air and Radiation
Office of Air Quality Planning and Standards
Air Quality Strategies and Standards Division
MD-15; Research Triangle Park, N.C. 27711

Final Report
May 1999

Disclaimer

This report is issued by the Air Quality Standards & Strategies Division of the Office of Air Quality Planning and Standards of the U.S. Environmental Protection Agency (EPA). It presents technical data on the National Emission Standard for Hazardous Air Pollutants (NESHAP), which is of interest to a limited number of readers. It should be read in conjunction with the Background Information Document (BID) for NESHAPs on the Oil and Natural Gas Production and Natural Gas Transmission and Storage source categories (April 1997). Both the Economic Impact Analysis and the BID are in the public docket for the NESHAP final rulemaking. Copies of these reports and other material supporting the rule are in Docket A-94-04 at EPA's Air and Radiation Docket and Information Center, Waterside Mall, Room M1500, Central Mall, 501 M Street, SW, Washington, DC 20460. The EPA may charge a reasonable fee for copying. Copies are also available through the National Technical Information Services, 5285 Port Royal Road, Springfield, VA 22161. Federal employees, current contractors and grantees, and nonprofit organizations may obtain copies from the Library Services Office (MD-35), U.S. Environmental Protection Agency, Research Triangle Park, NC 27711; phone (919) 541-2777.

TABLE OF CONTENTS

TABLE OF CONTENTS (continued)

Section | Page

TABLE OF CONTENTS (continued)

LIST OF FIGURES

LIST OF TABLES

LIST OF TABLES (Continued)

Number Page

LIST OF ACRONYMS

API	American Petroleum Institute
ATAC	Average total (avoidable) cost
Bcf	Billion cubic feet
BID	Background information document
BOE	Barrels of oil equivalent
BOPD	Barrels of oil per day
bpd	Barrels per day
BTB	Black oil tank battery
Btu	British thermal unit
cf(d)	Cubic feet (per day)
CIS	Commonwealth of Independent States
CTB	Condensate tank battery
D&B	Dun and Bradstreet
DEG	Diethylene glycol
DOE	Department of Energy
EG	Ethylene glycol
EIA	Energy Information Administration
FERC	Federal Energy Regulatory Commission
GRI	Gas Research Institute
HAPs	Hazardous air pollutants
IPAA	Independent Petroleum Association of America
ISEG	The Innovative Strategies and Economics Group
LDAR	Leak detection and repair
LPG	Liquid petroleum gas

MACT	Maximum achievable control technology
Mbpd	Thousand barrels per day
MC	Marginal cost
Mcf(d)	Thousand cubic feet (per day)
Mmbpd	Million barrels per day
MMBtu	Million British thermal units
MMcf(d)	Million cubic feet (per day)
MMS	Minerals Management Service
NAFTA	North American Free Trade Agreement
NESHAP	National Emission Standard for Hazardous Air Pollutants
NGL	Natural gas liquids
NGPA	Natural Gas Policy Act
NGPP	Natural gas processing plant
OGJ	Oil and Gas Journal
OPEC	Organization of Petroleum Exporting Countries
RCRA	Resource Conservation and Recovery Act
SBA	Small Business Administration
SIC	Standard Industrial Classification
TB	Tank battery
Tcf(d)	Trillion cubic feet (per day)
TEG	Triethylene glycol
TREG	Tetraethylene glycol

LIST OF DEFINITIONS

API Gravity--the gravity adopted by American Petroleum Institute for measuring the density of a liquid, expressed in degrees. It is converted from specific gravity by the following equation:

Degrees API gravity = 141.5/specific gravity - 131.5 *

Black Oil Tank Battery--the collection of process equipment used to separate, treat, store, and transfer streams from production wells primarily consisting of crude oil with little, if any, natural gas.

City Gate--the final destination of gas products prior to direct distribution to end users, such as homes, businesses, and industries.

Condensate Tank Battery--The collection of process equipment used to separate, treat, store, and transfer streams from production wells consisting of condensate and natural gas.

Condensates--hydrocarbons that are in a gaseous state under reservoir conditions (prior to production), but that become liquid during the production process.

Dry Gas--natural gas whose water content has been reduced through dehydration, or natural gas that contains little or no commercially recoverable liquid hydrocarbons.

End-user Price--the delivered price paid by residential, commercial, industrial, and electric utility consumers for natural gas.

Extracted Stream--the untreated mixture of gas, oil, condensate, water, and other liquids recovered at the wellhead.

Glycol Dehydration--absorption process in which a liquid absorbent, a glycol, directly contacts the natural gas stream

*Introduction to Oil and Gas Production. American Petroleum Institute. 1983.

and absorbs water vapor in a contact tower or absorption column. The glycol becomes saturated with water and is circulated through a boiler where the water vapor is boiled off.

Gruy "Wellgroups"--Gruy Engineering Corp. developed "wellgroups," or model production wells, for both oil and gas wells in 37 areas across the U.S. For each geographic area, wellgroups are defined by well depth ranges and by production rate in each depth range.

Natural Gas Processing Plant--a facility designed to (1) achieve the recovery of natural gas liquids from the stream of natural gas, which may or may not have been processed through lease separators and field facilities, and (2) control the quality of the natural gas to be marketed.*

Natural Gas--a mixture of hydrocarbons and varying quantities of nonhydrocarbons that exist either in gaseous phase or in solution with crude oil from underground reservoirs.

Offshore Production Platforms--facilities used to produce, treat, and separate crude oil, natural gas, and produced water in offshore areas.

Producing Field--an area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same geological structure feature and/or stratigraphic condition.*

Production Well--a hole drilled into the earth, usually cased with pipe for the recovery of crude oil, condensate, and natural gas.

Proved Crude Oil Reserves--the estimated amount of crude oil that can be found and developed in future years from known reservoirs under current prices and technology.

Proved Natural Gas Reserves--the estimated amount of gas that can be found and developed in future years from known reservoirs under current prices and technology.

Pump Stations--facilities designed to transport crude oil from tank batteries to refineries.

Stripper Wells--those production wells that produce less than 10 bpd or 60 Mcf per day.

---

*Introduction to Oil and Gas Production. American Petroleum Institute. 1983.

Wellhead Price--represents the wellhead sales price, including charges for natural gas plant liquids subsequently removed from the gas, gathering and compression charges, and State production, severance, and/or similar charges.

Wet Gas--unprocessed or partially processed natural gas produced from a reservoir that contains condensable hydrocarbons.

EXECUTIVE SUMMARY

The petroleum industry is divided into five distinct sectors: (1) exploration, (2) production, (3) transportation, (4) refining, and (5) marketing. The National Emission Standard for Hazardous Air Pollutants (NESHAP) establishes controls for the products and processes of the production and transportation sectors of the petroleum industry. Specifically, the oil and natural gas production and natural gas transmission and storage source categories include the separation, upgrading, storage, and transfer of extracted streams that are recovered from production wells. Thus, it includes the production and custody transfer up to the refinery stage for crude oil and up to the city gate for natural gas. This report evaluates the economic impacts of additional pollution control requirements for the oil and natural gas production and natural gas transmission and storage source categories that are designed to control releases of hazardous air pollutants (HAPs) to the atmosphere.

ES.1 INDUSTRY PROFILE

Production occurs within the contiguous 48 United States, Alaska, and at offshore facilities in Federal and State waters. In the production process, extracted streams from production wells are transported from the wellhead (through offshore production platforms in the case of offshore wells) to tank batteries for separation of crude oil, natural gas, condensates, and water from the product. Crude oil products are then transported to refineries, while natural gas products are directed to gas processing plants and then to final transmission lines at city gates. The equipment required in the production of crude oil and natural gas includes production wells (including offshore production platforms), dehydration units, tank batteries, natural gas processing plants, and transmission pipelines and underground storage facilities.

Because oil is an international commodity, the U.S. production of crude oil is affected by the world crude oil price, the price of alternative fuels, and existing regulations. Domestic oil production is currently in a state of decline that began in 1970. U.S. production in 1992 totaled only 7.2 million barrels per day (MMbpd)--the lowest level in 30 years.

Natural gas production trends are distinct from those of crude oil. Production has been increasing since 1986 mainly due to open access to pipeline transportation that has resulted in more marketing opportunities for producers and greater competition, leading to higher production. Also contributing to the increase in production are significant improvements in drilling productivity as well as more intensive utilization of existing fields since 1989. Natural gas consumers include residential and commercial customers, as well as industrial firms and electric utilities. Since 1986, natural gas consumption has shown relatively steady growth, which is projected to continue through the year 2010.

The oil and natural gas production industry is characterized by large (major) oil companies on one level and smaller independent producers on another level. Because of the existence of major oil companies, the industry possesses a wide dispersion of vertical and horizontal integration.

Several oil companies achieve full vertical integration in that they own and operate facilities that are involved in each of the five sectors within the petroleum industry. Independent companies, by definition, are involved in only a subset of these five sectors. Horizontal integration also exists in that major and independent firms may own and operate several crude oil and natural gas production and processing facilities.

ES.2 REGULATORY CONTROL OPTIONS AND COSTS

The Background Information Document (BID) details the technology basis for the national emission standards on affected sources. Model plants were developed to evaluate the effects of various control options on the oil and natural gas production industry and the transmission and storage industry. Selection of control options was based on the application of presently available control equipment and technologies and varying levels of capture consistent with different levels of overall control. The BID presents a summary of the control options for each of the following model plants:

- triethylene glycol (TEG) dehydration units,
- condensate tank batteries (CTB)
- natural gas processing plants (NGPP), and
- offshore production platforms (OPP).

Table ES-1 summarizes the annual compliance costs associated with the regulatory requirements for each model plant by source category. Major sources of HAP emissions are controlled based on the MACT floor, as defined in the BID. The Agency has determined that a glycol dehydration unit must be collocated at a facility for that facility to be designated as a major source. Therefore, the MACT floor may apply to stand-alone TEG units, condensate tank batteries, and natural gas processing plants. Black oil tank batteries and offshore production platforms are not considered since TEG units are not typical of the operations at black oil tank batteries and are completely controlled at offshore production platforms. Based on public comments on the proposed rule, EPA re-evaluated the costs and affected units in the Natural Gas Transmission and Storage sector. A full evaluation is presented in the BID, but a summary of costs are also presented in Table ES-1. The final rule for this industry will control major sources only, whereas the proposal for this rule evaluated control

TABLE ES-1. SUMMARY OF ANNUAL CONTROL COSTS BY MODEL PLANT

Model Plant	Cost per model unit
TEG dehydration units	
TEG-A	—
TEG-B	$12,989
TEG-C	$12,937
TEG-D	$12,790
TEG-E	$12,790
Condensate tank batteries	
CTB-E	—
CTB-F	$19,660
CTB-G	$24,973
CTB-H	$25,071
Natural gas processing plants	
NGPP-A	$46,747
NGPP-B	$61,823
NGPP-C	$81,083
Natural gas transmission and storage units	
TEG-A	-
TEG-B	-
TEG-C	-
TEG-D	$49,787
TEG-E	$49,787

requirements for major and area sources. Therefore, this EIA for the final rule only presents impacts on major sources.

ES.3 ECONOMIC IMPACT ANALYSIS

This economic impact analysis assesses the market-, facility-, and industry-level impact of the final rule on the oil and natural gas production industry. According to the BID, black oil tank batteries will not incur control costs so that only condensates processed at condensate tank batteries will be directly affected by the regulation. Condensates represent less than 5 percent of total U.S. crude oil production.[*] Thus, this analysis does not include a model to assess the regulatory effects on the world crude oil market because the anticipated changes in the U.S. supply are not likely to influence world prices. Consequently, the economic analysis focuses on the regulatory effects on the U.S. natural gas market that is modeled as a national, perfectly competitive market for a homogeneous commodity. In addition to the analysis presented at proposal, this EIA also incorporates an evaluation of the impact on the transmission and storage sector of the natural gas industry.

To estimate the economic impacts of the regulation on the natural gas market, a multi-dimensional Lotus spreadsheet model was developed incorporating various data sources to provide an empirical characterization of the U.S. natural gas industry for a base year of 1993--the latest year for which supporting technical and economic data were available at proposal. The analysis for the final rule maintains this base year to provide consistent comparisons between the final rule and proposed rule. The exogenous shock to the economic model is the imposition of the regulations and the corresponding control costs.

A competitive market structure was incorporated to compute the equilibrium prices (wellhead and end user) at which the supply and demand balance for natural gas output. Domestic supply is represented by a detailed characterization of the production flow of natural gas through a network of production wells and processing facilities. Demand for natural gas by end-use sector is expressed in equation form,

---

[*]Oil and Natural Gas Production: An Industry Profile. U.S. Environmental Protection Agency, OAQPS, Research Triangle Park, NC. October 1994. p. 4.

incorporating estimates of demand elasticities from the economic literature. Although the model includes a foreign component of U.S. natural gas supply (i.e., imports), it does not incorporate U.S. exports of natural gas that are observed at insignificant levels. The model analyzes market adjustments associated with the imposition of the regulation by employing a process of tatonnement whereby prices approach equilibrium through successive correction modeled as a Walrasian auctioneer.

As presented in Table ES-2, the major outputs of this model are market-level impacts, including price and quantity adjustments for natural gas and the impacts on foreign trade, and industry-level impacts, including the change in revenues and costs, adjustments in production, closures, and changes in employment. The market adjustments associated with the

TABLE ES-2. SUMMARY OF SELECTED ECONOMIC IMPACT RESULTS

Natural Gas Production	
Market-level impacts	
Prices(%)	0.0008%
Wellhead	0.0004%
End-user	
Domestic production (%)	-0.0003%
Industry-level impacts	
Change in revenues ($$10^6$)	$3.0
Change in costs (10^6)	$7.4
Change in profits ($$10^6$)	-$4.4
Closures	
Production wells	0
Natural gas processing plants	0
Employment losses	0
Economic welfare impacts ($$10^6$)	
Change in consumer surplus	-$0.3
Change in producer surplus	-$4.6
Domestic	-$4.7
Foreign	$0.1
Change in economic welfare	-$4.9

regulation are negligible in percentage terms (less than 0.01 percent) as well as in comparison to the observed trends in the U.S. natural gas market. For example, between 1992 and 1993, the average annual wellhead price increased by 14 percent, while domestic production of natural gas rose by 3 percent.

For transmission and storage, a screening analysis of impacts at the firm level was conducted. If this indicated substantial impacts a full market model as utilized for natural gas production could have been developed. The screening analysis showed:

1) that only 7 firms are estimated to be impacted,
2) that total compliance costs on this industry ($300,000) represent only 2/100ths of one percent (0.02%) of industry revenues, and

3) that compliance costs for individuals firms are likely to represent less than one percent of firm revenues for the affected firms.

Furthermore, the market adjustments in price and quantity allow calculation of the economic welfare impacts (i.e., changes in the aggregate economic welfare as measured by consumer and producer surplus changes). These estimates represent the social cost of the regulation. For natural gas production, transmission, and storage, the annual social cost of the regulation is $4.9 million. This measure of social cost is preferred to the national cost estimates from the engineering analysis because it accounts for the market adjustments and the associated deadweight loss to society of the reallocation of resources.

ES.4 REGULATORY FLEXIBILITY ANALYSIS

Environmental regulations such as this final rule for the oil and natural gas production and the natural gas transmission and storage industry affect all businesses, large and small, but small businesses may have special problems in complying with such regulations. The Regulatory Flexibility Act (RFA) of 1980 requires that special consideration be given to small entities affected by Federal regulation. Under the 1992 revised EPA guidelines for implementing the Regulatory Flexibility Act, an initial regulatory flexibility analysis (IRFA) and a final regulatory flexibility analysis (FRFA) will be performed for every rule subject to the Act that will have any economic impact, however small, on any small entities that are subject to the rule, however few, even though EPA may not be legally required to do so. The Small Business Regulatory Enforcement Fairness Act (SBREFA) of 1996 further amended the RFA by expanding judicial and small business review of EPA rulemaking. Although small business impacts are expected to be minimal due to the size cutoff for TEG dehydration units, this firm-level analysis addresses the RFA requirements by measuring the impacts on small entities.

Potentially affected firms include entities that own production wells and/or processing plants and equipment involved in oil and natural gas production, transmission or storage. For the production sector, we use financial information from the Oil and Gas Journal(OGJ)and financial ratios from Dun and Bradstreet to characterize the financial status of a sample of 80 firms potentially affected by the regulation. Firms in this sample include major and independent producers of oil and natural gas in addition to interstate pipeline and local distribution companies primarily involved in natural gas. According to Small Business Administration general size standard definitions for SIC codes, a total of 39 firms included in this analysis, or 48.8 percent, are defined as small. For the natural gas transmission and storage sector, we use information from the OGJs special issue of “Pipeline Economics” to determine impacts on small businesses. With regulation, the change in measures of profitability for production firms are minimal with no overall disparity across small and large firms, while the likelihood of financial failure is unaffected for both small and large firms. Likewise, for the transmission and storage sector, impacts are minimal because the majority of firms included in our analysis have compliance cost-to-revenues ratios below one percent. Therefore, there is no evidence of any disproportionate impacts on small entities due to the final rule on the oil and natural gas production industry.

SECTION 1
INTRODUCTION

The U.S. Environmental Protection Agency (EPA or the Agency) is developing an air pollution regulation for reducing emissions generated by the oil and natural gas production and natural gas transmission and storage source categories. EPA has developed a National Emission Standard for Hazardous Air Pollutants (NESHAP) for each category of major sources under the authority of Section 112(d) of the Clean Air Act as amended in 1990. The Innovative Strategies and Economics Group (ISEG) of EPA contributes to this effort by providing analyses and supporting documents that describe the likely economic impacts of the standards on directly and indirectly affected entities.

1.1 SCOPE AND PURPOSE

This report evaluates the economic impacts of pollution control requirements for the oil and natural gas production and natural gas transmission and storage source categories that are designed to control releases of hazardous air pollutants (HAPs) to the atmosphere. The Clean Air Act's purpose is "to protect and enhance the quality of the Nation's air resources" (Section 101[b]). Section 112 of the Clean Air Act as amended in 1990 establishes the authority to set national emission standards for the 189 HAPs listed in this section of the Act.

A major source is defined as a stationary source or group of stationary sources located within a contiguous area and under common control that emits, or has the potential to emit considering control, 10 tons or more of any one HAP or 25 tons or more of any combination of HAPs. Special provisions in Section 112(n)(4) for oil and gas wells and pipeline facilities affect major source determinations for these facilities.

For HAPs, the Agency establishes Maximum Achievable Control Technology (MACT) standards. The term "MACT floor" refers to the minimum control technology on which MACT can be based. For existing major sources, the MACT floor is the average emissions limitation achieved by the best performing 12 percent of sources (if the category or subcategory includes 30 or more sources), or the best performing five sources (if the category or subcategory includes fewer than 30 sources). MACT can be more stringent than the floor, considering costs, nonair quality health and environmental impacts, and energy requirements.

1.2 ORGANIZATION OF THE REPORT

The remainder of this report is divided into four sections that support and provide details on the methodology and results of this analysis. The sections include the following:

- Section 2 introduces the reader to the oil and natural gas production and natural gas transmission and storage source categories. It begins with an overview of the oil and natural gas industry and presents data on products and markets, production units, and the companies that own and operate the production and storage units.

- Section 3 reviews the model plants, regulatory control options, and associated costs of compliance as detailed in the draft Background Information Document (BID) prepared in support of the regulations.

- Section 4 describes the methodology for assessing the economic impacts of the regulation and the analysis results.

- Section 5 explains the methodology for assessing the company-level impacts of the regulation including an initial regulatory flexibility analysis to evaluate the small business effects of the regulation.

SECTION 2
INDUSTRY PROFILE

The petroleum industry is divided into five distinct sectors: (1) exploration, (2) production, (3) transportation, (4) refining, and (5) marketing. The NESHAP considers controls for the products and processes of the production and transportation sectors of the petroleum industry. Specifically, the oil and natural gas production and natural gas transmission and storage source categories include the separation, upgrading, storage, and transfer of extracted streams that are recovered from production wells. Thus, it includes the production and custody transfer up to the refining stage for crude oil and up to the city gate for natural gas.

Most crude oil and natural gas production facilities are classified under SIC code 1311--Crude Oil and Natural Gas Exploration and Production, while most natural gas transmission and storage facilities are classified under SIC 4923--Natural Gas Transmission and Distribution. The outputs of the oil and natural gas production industry--crude oil and natural gas--are the inputs for larger production processes of gas, energy, and petroleum products. In 1992, an estimated 594,189 crude oil wells and 280,899 natural gas production wells operated in the United States. U.S. natural gas production was 18.3 trillion cubic feet (Tcf) in 1993, continuing the upward trend since 1986, while U.S. crude oil production in 1992 was 7.2 million barrels per day (MMbpd), which is the lowest level in 30 years. The leading domestic oil and gas producing states are Alaska, Texas, Louisiana, California, Oklahoma, New Mexico, and Kansas.

The remainder of this section provides a brief introduction to the oil and natural gas production and transmission industries. The purpose is to give the reader a general understanding of the technical and economic aspects of the industry that must be addressed in the economic impact analysis. Section 2.1 provides an overview of the oil and natural gas production processes employed in the U.S. with an emphasis on those affected directly by the regulation. Section 2.2 presents historical data on crude oil and natural gas including reserves, production, consumption, and foreign trade. Section 2.3 summarizes the number of production facilities by type, location, and other parameters, while Section 2.4 provides general information on the potentially affected companies that own oil and natural gas production facilities.

2.1 PRODUCTION PROCESSES

Production occurs within the contiguous 48 United States, Alaska, and at offshore facilities in Federal and State waters. Figure 2-1 shows that, in the production process, extracted streams from production wells are transported from the wellhead (through offshore production platforms in the case of offshore wells) to tank batteries to separate crude oil, natural gas, condensates, and water from the product. Crude oil products are then transported through pump stations to a refinery, while natural gas products are directed to gas processing plants and then to final transmission lines at city gates. The equipment required in the production of crude oil and natural gas includes production wells (including offshore production platforms), separators, dehydration units, tank batteries, and natural gas processing plants.

2.1.1 Production Wells and Extracted Products

The type of production well used in the extraction process depends on the region of the country in which the well

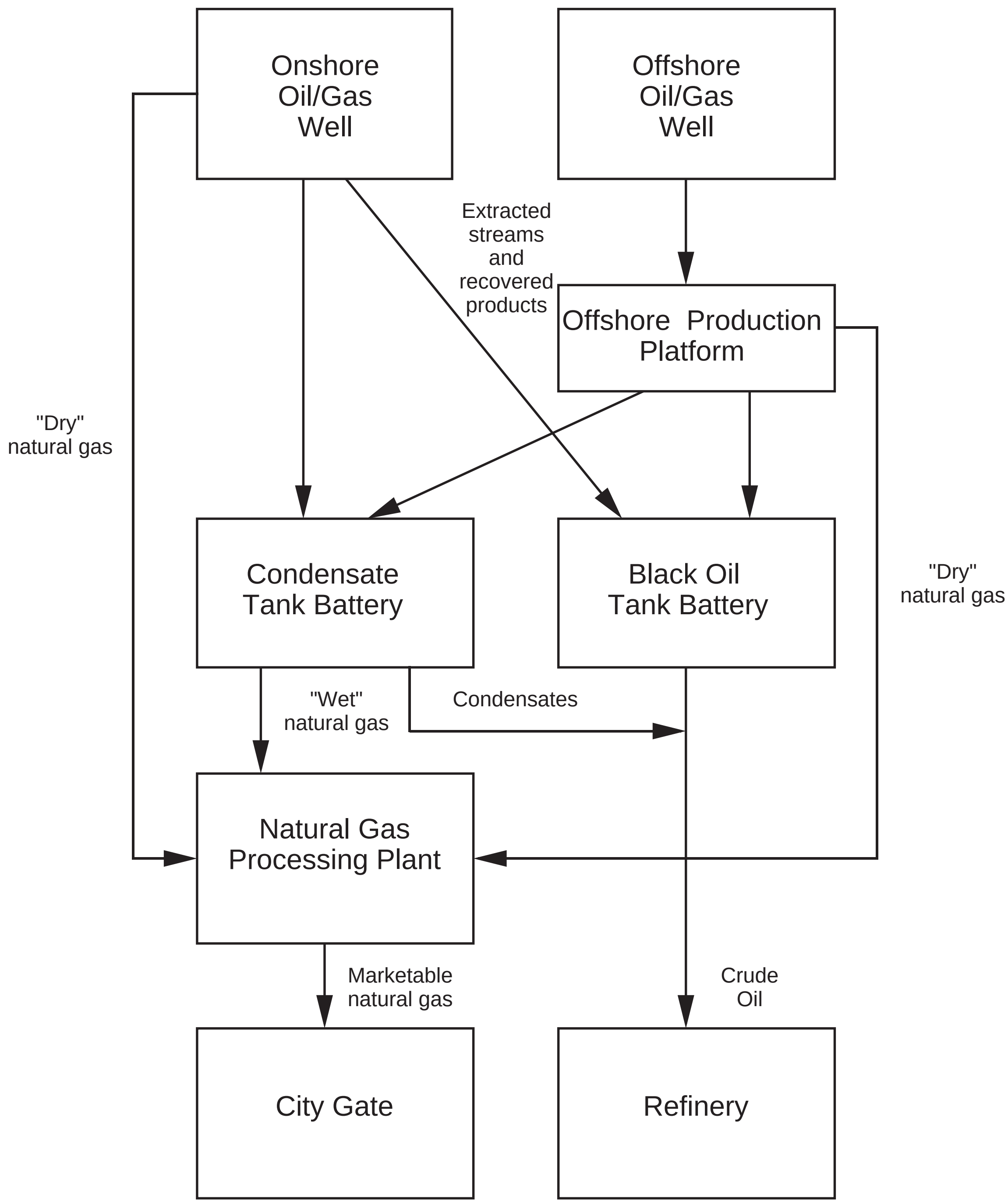


Figure 2-1. Crude oil and natural gas production flow diagram.

is drilled and the composition of the well stream. The recovered natural resources are naturally or artificially brought to the surface where the products (crude oil, condensate, and natural gas) are separated from produced water and other impurities. Offshore production platforms are used to extract, treat, and separate recovered products in offshore areas. Processes and operations at offshore production platforms are similar to those located at onshore facilities except that offshore platforms generally have little or no storage capacity because of the limited available space.[1]

Each producing well has its own unique properties in that the composition of the well stream (i.e., crude oil and the attendant gas) is different from that of any other well. As a result, most wells produce a combination of oil and gas; however, some wells can produce primarily crude oil and condensate with little natural gas, while others may produce only natural gas. The primary extracted streams and recovered products associated with the oil and natural gas industry include crude oil, natural gas, condensate, and produced water. These are briefly described below.

Crude oil can be broadly classified as paraffinic, naphthenic, or intermediate. Paraffinic (or heavy) crude is used as an input to the manufacture of lube oils and kerosene. Naphthenic (or light) crude is used as an input to the manufacture of gasolines and asphalt. Intermediate crudes are those that do not fit into either category. The classification of crude oil is determined by a gravity measure developed by the American Petroleum Institute (API). API gravity is a weight per unit volume measure of a hydrocarbon liquid as determined by a method recommended by the API. A heavy or paraffinic crude is one with an API gravity of 20° or less, and a light or naphthenic crude, which flows freely at atmospheric temperatures, usually has an API gravity in the range of the high 30s to the low 40s.[2]

Natural gas is a mixture of hydrocarbons and varying quantities of nonhydrocarbons that exist either in gaseous phase or in solution with crude oil from underground reservoirs. Natural gas may be classified as wet or dry gas. Wet gas is unprocessed or partially processed natural gas produced from a reservoir that contains condensable hydrocarbons. Dry gas is natural gas whose water content has been reduced through dehydration, or natural gas that contains little or no commercially recoverable liquid hydrocarbons.

Condensates are hydrocarbons that are in a gaseous state under reservoir conditions (prior to production), but which become liquid during the production process. Condensates have an API gravity in the 50° to 120° range.[3] According to historical data, condensates account for approximately 4.5 to 5 percent of total crude oil production.

Produced water is recovered from a production well or is separated from the extracted hydrocarbon streams. More than 90 percent of produced water is reinjected into the well for disposal and to enhance production by providing increased pressure during extraction. An additional 7 percent of produced water is released into surface water under provisions of the Clean Water Act. The remaining 3 percent of produced water extracted from production wells is disposed of as waste.

In addition to the products discussed above, other various hydrocarbons may be recovered through the processing of the extracted streams. These hydrocarbons include mixed natural gas liquids, natural gasoline, propane, butane, and liquefied petroleum gas.

2.1.2 Dehydration Units

Once the natural gas has been separated from the crude oil or condensate and water, residual water is removed from the natural gas by dehydration to meet sales contract specifications or to improve heating values for fuel consumption. Liquid desiccant dehydration is the most widespread technology used for natural gas with the most common process being a basic glycol system. Glycol dehydration is an absorption process in which a liquid absorbent, a glycol, directly contacts the natural gas stream and absorbs the water vapor that is later boiled off. Glycol units in operation today may use ethylene glycol (EG), diethylene glycol (DEG), triethylene glycol (TEG), and tetraethylene glycol (TREG).[4]

Dehydration units are used at several processing points in the process to remove water vapor from the gas once it has been separated from the crude oil or condensate and water. Locations where dehydration may occur include the production well site, the condensate tank battery, the natural gas processing plant, aboveground and underground storage facilities upon removal, and the city gate.

2.1.3 Tank Batteries

A tank battery refers to the collection of process equipment used to separate, treat, store, and transfer crude oil, condensate, natural gas, and produced water. As shown in Figure 2-2, the extracted products enter the tank battery through the production header, which may collect the product from many production wells. Process equipment at a tank battery may include separators that separate the product from basic sediment and water; dehydration units; heater treaters, free water knockouts, and gunbarrel separation tanks that basically remove water and gas from crude oil; and storage tanks that temporarily store produced water and crude oil.[5]

Tank batteries are classified as black oil tank batteries if the extracted stream from the production wells primarily

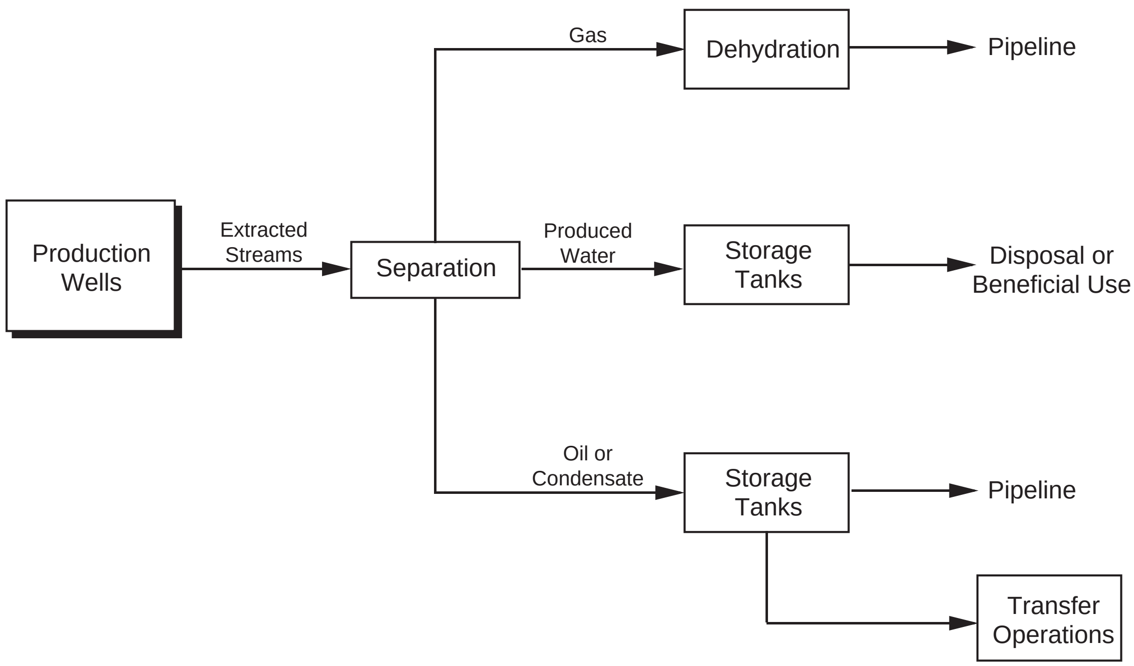


Figure 2-2. Summary of processes at a tank battery.

consists of crude oil that has little, if any, associated gas. In general, any associated gas recovered at a black oil tank battery is flared. Condensate tank batteries are those that process extracted streams from production wells consisting of condensate and natural gas. Dehydration units are part of the process equipment at condensate tank batteries but not at black oil tank batteries.

2.1.4 Natural Gas Processing Plants

Natural gas that is separated from other products of the extracted stream at the tank battery is then transferred via pipeline to a natural gas processing plant. As shown in Figure 2-3 the main functions of a natural gas processing plant include conditioning the gas by separation of natural gas liquids (NGL) from the gas and fractionation of NGLs into separate components, or desired products that include ethane, propane, butane, liquid petroleum gas, and natural gasoline. Generally, gas is dehydrated prior to other processes at a plant. Another function of these facilities is to control the quality of the processed natural gas stream. If the natural gas contains hydrogen sulfide and carbon dioxide, then

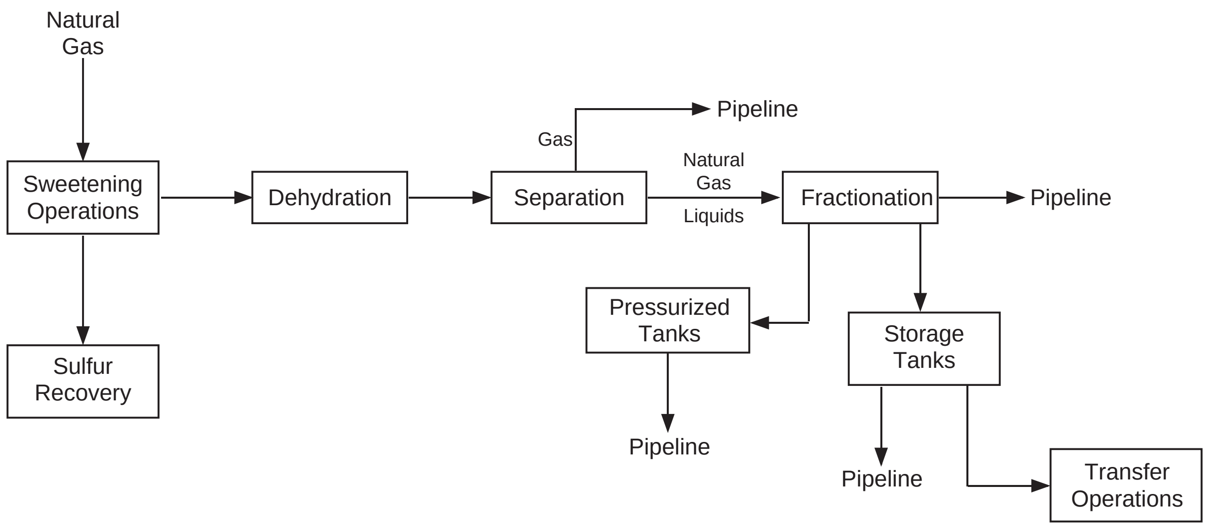


Figure 2-3. Summary of processes at natural gas processing plant.

sweetening operations are employed to remove these contaminants from the natural gas stream immediately after separation and dehydration.

2.1.5 Natural Gas Transmission and Storage Facilities

After processing, natural gas enters a network of pipelines and storage systems. The natural gas transmission and storage source category consists of gathering lines, compressor stations, high-pressure transmission pipeline, and underground storage sites.

Compressor stations are any facility which supplies energy to move natural gas at increased pressure in transmission pipelines or into underground storage. Typically, compressor stations are located at intervals along a transmission pipeline to maintain desired pressure for natural gas transport. These stations will use either large internal combustion engines or gas turbines as prime movers to provide the necessary horsepower to maintain system pressure.

Underground storage facilities are subsurface facilities utilized for storing natural gas which has been transferred from its original location for the primary purpose of load balancing, which is the process of equalizing the receipt and delivery of natural gas. Processes and operations that may be located at underground storage facilities include compression and dehydration.

2.2 PRODUCTS AND MARKETS

Crude oil and natural gas have historically served two separate and distinct markets. Oil is an international commodity, transported and consumed throughout the world. Natural gas, on the other hand, is typically consumed close to where it is produced. Final products of crude oil are used primarily as engine fuel for automobiles, airplanes, and other types of vehicles. Natural gas, on the other hand, is used primarily as boiler fuel for industrial, commercial, and residential applications.

2.2.1 Crude Oil

The following subsections provide historical data on the U.S. reserves, production, consumption, and foreign trade of crude oil.

2.2.1.1 Reserves. The Department of Energy defines oil reserves as "oil reserves that data demonstrate are capable of being recovered in the future given existing economic and operating conditions."[6] Table 2-1 provides total U.S. crude oil reserves for 1976 through 1993.[7] Crude oil reserves continued their decline for the sixth consecutive year in 1993, dropping by 788 million barrels (3.3 percent) to 2.3 billion barrels. Low oil prices and decreased drilling activity are the major factors for these recent declines.

Table 2-2 presents the U.S. proved reserves of crude oil as of December 31, 1993, by State or producing area.[8] As this table indicates, five areas currently account for 80 percent of the U.S. total proved reserves of crude oil with Texas leading all other areas, followed closely by Alaska, California, the Gulf of Mexico, and New Mexico. Texas, Alaska, and California accounted for roughly 82 percent of the overall decline in crude oil reserves from 1992 to 1993. Meanwhile, the Gulf of Mexico Federal Offshore had an oil reserve increase of 237 million barrels.

2.2.1.2 Domestic Production. Because oil is an international commodity, the U.S. production of crude oil is affected by the world crude oil price, the price of

TABLE 2-1. TOTAL U.S. PROVED RESERVES OF CRUDE OIL, 1976 THROUGH 1993
(million barrels of 42 U.S. gallons)

Year	Total discoveries	Production	Proved reserves
1976			33,502[a]
1977	794	2,862	31,780
1978	827	3,008	31,355
1979	636	2,955	29,810
1980	862	2,975	29,805
1981	1,161	2,949	29,426
1982	1,031	2,950	27,858
1983	924	3,020	27,735
1984	1,144	3,037	28,446
1985	995	3,052	28,416
1986	534	2,973	26,889
1987	691	2,873	27,256
1988	553	2,811	26,825
1989	716	2,586	26,501
1990	689	2,505	26,254
1991	554	2,512	24,682
1992	484	2,446	23,745
1993	785	2,339	22,957

[a]Based on following year data only.

Source: U.S. Department of Energy. Energy Information Administration. U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves: 1993 Annual Report. October 1994.

alternative fuels, and existing regulations. Domestic oil production is currently in a state of decline that began in 1970. Table 2-3 shows U.S. production in 1992 at 7.2 MMbpd, which is the lowest level in 30 years.[9] Domestic production of crude oil has dropped by almost 2 MMbpd since 1985. This decline has been attributed to a transfer of U.S. investment from domestic sources to foreign production.*

*The investment in foreign ventures is spurred by low labor costs and less stringent regulatory environments abroad, as well as the increased likelihood of discovering larger fields in overseas activity.

TABLE 2-2. U.S. CRUDE OIL RESERVES BY STATE AND AREA, 1993
(million barrels)

State/area	Proved reserves 12/31/92	Total discoveries and adjustments	Production	Proved reserves 12/31/93
Alaska	6,022	332	579	5,775
Alabama	41	10	10	41
Arkansas	58	17	10	65
California	3,893	161	290	3,764
Colorado	304	10	30	284
Florida	36	10	6	40
Illinois	138	-7	15	116
Indiana	17	0	2	15
Kansas	310	9	48	271
Kentucky	34	-5	3	26
Louisiana	668	77	106	639
Michigan	102	0	12	90
Mississippi	165	-12	20	133
Montana	193	-6	16	171
Nebraska	26	-1	5	20
New Mexico	757	14	64	707
North Dakota	237	19	30	226
Ohio	58	4	8	54
Oklahoma	698	68	86	680
Pennsylvania	16	-1	1	14
Texas	6,441	309	579	6,171
Utah	217	31	20	228
West Virginia	27	-1	2	24
Wyoming	689	13	78	624
Federal offshore	2,569	492	316	2,745
Pacific (California)	734	-11	50	673
Gulf of Mexico (Louisiana)	1,643	489	252	1,880
Gulf of Mexico (Texas)	192	14	14	192
Miscellaneous	29	8	3	34
Total, lower 48 States	17,723	1,219	1,760	17,182
Total, U.S.	23,745	1,551	2,339	22,957

Source: U.S. Department of Energy. Energy Information Administration. U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves: 1993 Annual Report. October 1994.

TABLE 2-3. U.S. CRUDE OIL PRODUCTION, 1982-1992

Year	Crude oil production (MMbpd)
1982	8.65
1983	8.69
1984	8.88
1985	9.00
1986	8.68
1987	8.35
1988	8.14
1989	7.61
1990	7.36
1991	7.42
1992	7.17

Source: U.S. Department of Energy. Petroleum Supply Annual 1992. DOE/EIA-0340(92)-1. Vol. 1. May 1993.

2.2.1.3 Domestic Consumption. Crude oil is the primary input to the production of several petroleum products. Consequently, the demand for crude oil is derived from the demand of these final products. Final petroleum products include motor gasoline, diesel fuel, jet fuel, and fuels for the industrial, residential, and commercial sectors as well as for electric utilities. Historical crude oil consumption trends for 1980 through 1992 are shown in Table 2-4.[10,11] As shown in this table, a slight upturn in demand occurred in 1988, and consumption then remained fairly constant through 1992.

2.2.1.4 Foreign Trade. The world oil market is unique in that it is dominated by the Organization of Petroleum Exporting Countries (OPEC), which applies the following

TABLE 2-4. TOTAL U.S. CRUDE OIL CONSUMPTION AND PRICE LEVELS, 1980-1992

Year	Domestic consumption (MMbpd)	Crude oil domestic wellhead price ($/barrel)	
		Current dollars	Constant 1990 dollars
1980	17.06	21.6	34.2
1981	16.06	31.8	45.7
1982	15.30	28.5	38.6
1983	15.23	26.2	34.4
1984	15.73	25.9	32.6
1985	15.73	24.1	29.3
1986	16.28	12.5	14.9
1987	16.67	15.4	17.7
1988	17.28	12.6	13.9
1989	17.33	15.9	16.8
1990	16.99	20.0	20.0
1991	16.70	16.5	15.8
1992	17.00	16.0	14.7

Sources: U.S. Department of Energy. Petroleum Supply Annual 1992. DOE/EIA-0340(92)-1. Vol. 1. May 1993.
U.S. Department of Energy. Natural Gas Annual 1991. DOE/EIA-0131(91). Washington, DC. October 1992.

economic principle: if supply is restricted, prices will rise. OPEC accounts for 38 percent of the world oil supply, while the U.S. accounts for 12 percent. Supplies from the OPEC exert a significant influence on domestic crude oil foreign trade levels. In February 1992, OPEC reimposed quotas on individual country output. The new quota signified a reduction in production intended to alter world oil prices. Any future additions to OPEC supply could reduce world crude oil prices. Additionally, if supplies to the world oil supply from the Commonwealth of Independent States (CIS) continue to decline, excess OPEC supplies can be absorbed without a significant crude oil price reduction.

As Table 2-5 demonstrates, U.S. imports of crude oil have increased steadily since 1983 at an average annual growth rate of 9.6 percent, while U.S. exports have steadily declined at an average of 4 percent annually.[12] This has resulted in a net import level in 1992 of 6 MMbpd. Oil imports are projected to exceed 8.2 MMbpd in 1993. This annual growth rate of 4.7 percent is measurably higher than the 2.9 percent rate registered in 1992.[13] Total oil imports are predicted to reach 10.1 MMbpd by the year 2000. This predicted rise in imports of crude oil corresponds to an average annual increase of 3.4 percent. The import dependency ratio is forecast to rise to 55 percent in 2000, compared to 48 percent in 1993.[14] As a result of the historical decline in domestic production and increases in demand levels, net imports of crude oil are expected to continue to increase.

TABLE 2-5. SUMMARY OF U.S. FOREIGN TRADE OF CRUDE OIL, 1983-1992

Year	Imports (MMbpd)	Domestic crude oil consumption (MMbpd)	Import percentage of domestic consumption	Exports (MMbpd)	Domestic crude oil output (MMbpd)	Export percentage of domestic output
1983	3.10	15.23	20.3	0.16	8.6	2.0
1984	3.23	15.73	20.5	0.18	8.9	2.0
1985	3.08	15.73	19.6	0.20	9.0	2.2
1986	4.13	16.28	25.4	0.15	8.7	1.7
1987	4.60	16.67	27.6	0.15	8.3	1.8
1988	5.06	17.28	29.3	0.15	8.1	1.9
1989	5.79	17.33	33.4	0.14	7.6	1.8
1990	5.87	16.99	34.5	0.11	7.4	1.5
1991	5.78	16.70	34.6	0.12	7.4	1.6
1992	6.07	17.00	35.7	0.09	7.2	1.3

Source: U.S. Department of Energy. Annual Energy Review 1991. DOE/EIA-0384(91). June 1992.

2.2.1.5 Future Trends. Table 2-6 presents the U.S. Department of Energy's annual projections of crude oil production, consumption, and world oil price from 1993 through 2010 based on two rates of economic growth and two possible oil price scenarios.[15] U.S. crude oil supply is predicted to continue to decline between 1993 and 2010, due to low levels of drilling activities in recent years. The range of projections for 2010 is from 6.2 to 3.6 MMbpd. According to the Independent Petroleum Association of America (IPAA), U.S. crude oil production is predicted to continue its decline from 7.0 MMbpd in 1993 to 6 MMbpd by 2000.[16] This will be the lowest oil output level since 1950.

TABLE 2-6. SUPPLY, DEMAND, AND PRICE PROJECTIONS FOR CRUDE OIL, 1993-2010

Item	Actual 1993	Alternative projections to 2010			
		High economic growth	Low economic growth	High oil price	Low oil price
Production (MMbpd)	6.85	5.57	5.23	6.20	3.58
Consumption[a] (MMbpd)	15.30	15.9	15.9	15.8	16.00
World oil price (1993 $/barrel)	16.12	24.99	23.29	28.99	14.65

[a]Consumption is measured by U.S. refinery capacity.

Source: U.S. Department of Energy. Annual Energy Outlook 1995. DOE/EIA-0383(95). January 1995.

2.2.2 Natural Gas

The following subsections provide historical data on the U.S. reserves, production, consumption, and foreign trade of natural gas.

2.2.2.1 Reserves. Proved reserves of natural gas are the estimated amount of gas that can be found and developed in future years from known reservoirs under current prices and technologies.[17] Table 2-7 provides total U.S. natural gas reserves for 1976 through 1993.[18] Although natural gas discoveries were up considerably in 1993, increased production along with lower revisions and adjustments (resulting from new information about known gas reservoirs) led to a decline in overall natural gas reserves of 2.6 Tcf to total 162.4 Tcf. This decline reflects a 1.6 percent change in reserves from the 1992 level.

TABLE 2-7. U.S. PROVED RESERVES OF DRY NATURAL GAS, 1976 THROUGH 1993
(billion cubic feet [Bcf] at 14.73 psia and 60° F)

Year	Total discoveries	Production	Proved reserves
1976			213,278[a]
1977	14,603	18,843	207,413
1978	18,021	18,805	208,033
1979	14,704	19,257	200,997
1980	14,473	18,699	199,021
1981	17,220	18,737	201,730
1982	14,455	17,506	201,512
1983	11,448	15,788	200,247
1984	13,521	17,193	197,463
1985	11,128	15,985	193,369
1986	8,935	15,610	191,586
1987	7,175	16,114	187,211
1988	10,350	16,670	168,024
1989	10,032	16,983	167,116
1990	12,368	17,233	169,346
1991	7,542	17,202	167,062
1992	7,048	17,423	165,015
1993	8,868	17,789	162,415

[a]Based on following year data only.

Source: U.S. Department of Energy. Energy Information Administration. U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves: 1993 Annual Report. October 1994.

Table 2-8 presents the U.S. proved reserves of natural gas as of December 31, 1993, by State or producing area.[19,20] As indicated by this table, the five leading gas producing areas of Texas, the Gulf of Mexico, Oklahoma, Louisiana, and New Mexico all had declines in proved reserves from 1992 to 1993 totaling 2.6 Tcf. These declines were partially offset by substantial increases in Virginia and Colorado, where gas reserves increased by 942 Bcf over 1992.

2.2.2.2 Domestic Production. Natural gas production trends are distinct from those of crude oil. As shown in Table 2-9, production has been increasing since 1986.[21,22] This trend can be partially attributed to open access to pipeline transportation, which has resulted in more marketing opportunities for producers and greater competition, leading to higher production. Traditionally, most natural gas sold at the wellhead was sold under long-term, price-regulated contracts and purchased by pipeline companies. These pipeline companies in turn resold it to local distribution companies (from the "wellhead" to the "city gate"). Therefore, the pipelines transported natural gas as part of a larger package of "bundled" services that include acquisition and transportation. Local distribution companies then distribute gas to residential, commercial, and industrial customers and electric utilities (from the "city gate" to the "burner tip"). The end-user price thus reflected the cost of acquisition plus the cost of transport and other services along with the regulator-specified fair rate of return on investment.

The Natural Gas Policy Act (NGPA) of 1978 and subsequent Federal Energy Regulatory Commission (FERC) orders throughout the 1980s promoting open access transportation have dramatically altered the industry organization of the U.S.

TABLE 2-8. U.S. NATURAL GAS RESERVES BY STATE AND AREA, 1993 (Bcf)

State/area	Proved reserves 12/30/92	Total discoveries and adjustments	Production	Proved reserves 12/30/93
Alaska	9,725	657	396	9,986
Alabama	5,870	-371	287	5,212
Arkansas	1,752	-9	188	1,555
California	2,892	169	262	2,799
Colorado	6,463	922	406	6,979
Florida	55	12	8	59
Kansas	10,302	264	694	9,872
Kentucky	1,126	-22	68	1,036
Louisiana	10,227	830	1,516	9,541
Michigan	1,290	75	147	1,218
Mississippi	873	38	111	800
Montana	875	-141	50	684
New Mexico	20,339	1,019	1,419	19,939
New York	329	-43	22	264
North Dakota	567	75	57	585
Ohio	1,161	66	121	1,106
Oklahoma	14,732	1,246	1,879	14,099
Pennsylvania	1,533	328	139	1,722
Texas	38,141	4,736	5,030	37,847
Utah	2,018	358	178	2,198
Virginia	904	454	36	1,322
West Virginia	2,491	286	179	2,598
Wyoming	11,305	824	742	11,387
Federal offshore	28,186	4,096	4,696	27,586
Pacific (California)	1,136	32	45	1,123
Gulf of Mexico (Louisiana)	20,006	3,128	3,383	19,751
Gulf of Mexico (Texas)	7,044	936	1,268	6,712
Other states	93	13	10	96
Total, lower 48 States	163,584	15,165	18,245	160,504
Total, U.S.	173,309	15,822	18,641	170,490

Sources: U.S. Department of Energy, Petroleum Supply Annual 1992. DOE/EIA-0340(92)-1. Vol. 1. May 1993.
U.S. Department of Energy. Natural Gas Annual 1991. DOE/EIA-0131(91). Washington, DC. October 1992.

TABLE 2-9. U.S. NATURAL GAS PRODUCTION AND WELLHEAD PRICE LEVELS, 1980-1992

Year	Domestic production (Tcf)	Average annual wellhead price ($/Mcf) Current dollars	Average annual wellhead price ($/Mcf) Constant 1990 dollars
1980	20.18	1.6	2.5
1981	19.96	2.0	2.9
1982	17.82	2.5	3.4
1983	16.09	2.6	3.4
1984	17.47	2.7	3.3
1985	16.45	2.5	3.0
1986	16.06	1.9	2.3
1987	16.62	1.7	2.0
1988	17.10	1.7	1.9
1989	17.31	1.7	1.8
1990	17.81	1.7	1.7
1991	17.87	1.6	1.5
1992	18.47	1.8	1.7

Sources: U.S. Department of Energy. Petroleum Supply Annual 1992. DOE/EIA-0340(92)-1. Vol. 1. May 1993.
U.S. Department of Energy. Natural Gas Annual 1991. DOE/EIA-0131(91). Washington, DC. October 1992.

market for natural gas by separating the marketing and transport functions of interstate pipeline companies.* With the separation of transportation from production in the industry, much of the natural gas is purchased directly from producers, and the pipeline companies principally provide transportation services for their customers. Independent

*These Federal Energy Regulatory Commission orders include FERC Order No. 380, which effectively eliminated the requirement that customers of interstate pipelines purchase any minimum quantity of natural gas, and FERC Order No. 636, which mandates that pipelines must separate gas sales from transportation, thereby allowing open access to pipeline transportation for gas producers and customers.

brokers and other marketers service these transactions and bypass the traditional marketing structure.[*,23]

Also contributing to the increase in production shown in Table 2-9 are significant improvements in drilling productivity as well as more intensive utilization of existing fields since 1989. Because of lower prices in 1990 and 1991, however, producers have curtailed drilling programs and have sought ways to cut production costs, for example, by more intensive development of profitable onshore fields.

2.2.2.3 Domestic Consumption. Table 2-10 displays natural gas consumption by end user from 1980 to 1992, while Table 2-11 presents end-user prices for natural gas for the same time period.[24,25] Natural gas users include residential and commercial customers, as well as industrial firms and electric utilities. Since 1986, natural gas consumption has shown relatively steady growth, which is projected to continue through the year 2010. Because some consumers can substitute certain petroleum products for natural gas, prices of oil and gas often move in the same direction. Low crude oil prices after the 1986 price collapse, for example, effectively pushed competing gas prices lower.

2.2.2.4 Foreign Trade. On the international market, the U.S. and Canada are the world's leading producers of natural gas, accounting for more than 59 percent of the worldwide gas processing capacity (the U.S. accounts for nearly 42 percent alone) and more than 57 percent of world natural gas production. Table 2-12 displays the level of imports and exports of natural gas as well as the import share

[*]Based on USDOE/EIA information for 1991, 84 percent of natural gas was transported to the market for marketers, local distribution companies (LDCs), and end users (45 percent for independent brokers and other marketers, 32 percent for local distribution companies, and 7 percent directly to end users) as compared with only 3 percent in 1982. The remaining 16 percent in 1991 was purchased at the wellhead by interstate pipeline companies for distribution.

TABLE 2-10. U.S. NATURAL GAS CONSUMPTION BY END-USE SECTOR, 1980-1992

	End-user consumption (Tcf)					
Year	Residential	Commercial	Industrial	Electric utilities	Other[a]	Total
1980	4.75	2.61	7.17	3.68	1.66	19.88
1981	4.55	2.52	7.13	3.64	1.57	19.40
1982	4.63	2.60	5.83	3.23	1.71	18.00
1983	4.38	2.43	5.64	2.91	1.47	16.84
1984	4.56	2.52	6.15	3.11	1.61	17.95
1985	4.43	2.43	5.90	3.04	1.47	17.28
1986	4.31	2.32	5.58	2.60	1.41	16.22
1987	4.31	2.43	5.95	2.84	1.67	17.21
1988	4.63	2.67	6.38	2.64	1.71	18.03
1989	4.78	2.71	6.82	2.79	1.70	18.80
1990	4.39	2.62	7.02	2.79	1.90	18.72
1991	4.56	2.73	7.23	2.79	1.75	19.05
1992	4.70	2.77	7.64	2.77	1.85	19.75

[a]Includes natural gas consumed as lease, plant, and pipeline fuel.

Source: Energy Statistics Sourcebook, 8th ed. PennWell Publishing Co. September 1993.

of U.S. domestic consumption and the export share of U.S. marketed production for the years 1973 through 1993. North American gas trade is a major factor in the competitive U.S. natural gas market. Natural gas imports no longer serve as a marginal source of supply but are actively competing for market share. As shown in Table 2-12, imports increased by 6 percent to 2.3 Tcf from 1992 to 1993 providing 11 percent of U.S. domestic consumption.[26] Canadian suppliers account for most of the natural gas imports to the United States. Although no significant changes in gas trade with Mexico are expected in the near future, the North American Free Trade Agreement (NAFTA) will assist in developing and integrating the Mexican gas industry.[27]

TABLE 2-11. U.S. NATURAL GAS PRICE BY END-USE SECTOR, 1980-1992

	End-use sector ($/Mcf)				
Year	Residential	Commercial	Industrial	Electric utilities	Average
1980	$3.68	$3.39	$2.56	$2.27	$2.91
1981	$4.29	$4.00	$3.14	$2.89	$3.51
1982	$5.17	$4.82	$3.87	$3.48	$4.32
1983	$6.06	$5.59	$4.18	$3.58	$4.82
1984	$6.12	$5.55	$4.22	$3.70	$4.85
1985	$6.12	$5.50	$3.95	$3.55	$4.72
1986	$5.83	$5.00	$3.23	$2.43	$4.13
1987	$5.54	$4.77	$2.94	$2.32	$4.05
1988	$5.47	$4.63	$2.95	$2.33	$4.09
1989	$5.64	$4.74	$2.96	$2.43	$4.22
1990	$5.80	$4.83	$2.93	$2.39	$4.20
1991	$5.82	$4.81	$2.69	$2.18	NA
1992	$5.86	$4.87	$2.81	$2.37	NA

Source: Energy Statistics Sourcebook, 8th ed. Penn Well Publishing Co. September 1993.

Historically, imports of natural gas have increased at an average annual growth rate of 10.5 percent. Increases in natural gas imports have been driven by increased U.S. demand and additions to interstate pipeline capacity in 1991 and 1992. Exports have doubled since 1983 although yearly fluctuations have occurred. Net import levels have steadily increased over this time period to 1.79 Tcf in 1992. According to the IPAA, total gas imports, mainly from Canada, are expected to rise to 3.1 Tcf by 2000, up from 2.2 Tcf in 1992. This is an average increase of nearly 6 percent each year.

2.2.2.5 Future Trends. Currently, the domestic natural gas production industry is in transition from a period

TABLE 2-12. HISTORICAL SUMMARY OF U.S. NATURAL GAS FOREIGN TRADE, 1973-1993
(Bcf)

Year	Total imports	Total exports	Net imports	Total consumption	Net imports as a percentage of total consumption	Marketed production	Exports as a percentage of marketed production
1973	1,032.9	77.2	955.7	22,049.4	4.3	22,647.6	0.3
1974	959.2	76.8	882.5	21,223.1	4.2	21,600.5	0.4
1975	953.0	72.7	880.3	19,537.6	4.5	20,108.7	0.4
1976	963.8	64.7	899.1	19,946.5	4.5	19,952.4	0.3
1977	1,011.0	55.6	955.4	19,520.6	4.9	20,025.5	0.3
1978	965.5	52.5	913.0	19,627.5	4.7	19,974.0	0.3
1979	1,253.4	55.7	1,197.7	20,240.8	5.9	20,471.3	0.3
1980	984.8	48.7	936.0	19,877.3	4.7	20,379.7	0.2
1981	903.9	59.4	844.6	19,403.9	4.4	20,177.0	0.3
1982	933.3	51.7	881.6	18,001.1	4.9	18,519.7	0.3
1983	918.4	54.6	863.8	16,834.9	5.1	16,822.1	0.3
1984	843.0	54.8	788.3	17,950.5	4.4	18,229.6	0.3
1985	949.7	55.3	894.4	17,280.9	5.2	17,197.9	0.3
1986	750.5	61.3	689.2	16,221.3	4.2	16,858.7	0.4
1987	992.5	54.0	938.5	17,210.8	5.5	17,432.9	0.3
1988	1,293.8	73.6	1,220.2	18,029.6	6.8	17,918.5	0.4
1989	1,381.5	106.9	1,274.6	18,800.8	6.8	18,095.1	0.6
1990	1,532.3	85.6	1,446.7	18,716.3	7.7	18,593.8	0.5
1991	1,773.3	129.2	1,644.1	19,129.4	8.6	18,585.8	0.7
1992	2,137.5	216.3	1,921.2	19,726.2	9.7	18,616.9	1.2
1993	2,350.1	140.2	2,209.9	20,219.0[a]	10.9	19,251.0	0.7

[a]Preliminary data.

Notes: Totals may not equal sum of components due to independent rounding. Geographic coverage is the continental United States including Alaska.

Source: U.S. Department of Energy. Energy Information Administration. Natural Gas Monthly U.S. Natural Gas Imports and Exports--1993. August 1994.

of overcapacity to one near full capacity utilization. Since 1985, demand has grown in response to low prices while drilling activity remained depressed, lowering the gap that existed between demand and supply levels. While the U.S. has a relatively large potential gas reserve base available for development, current low market prices must increase to stimulate new drilling activity and meet projected demand growth. Natural gas supplies are expected to continue to increase through the 1990s, slowing near 2000 as deliverability through existing pipelines constrains the development of some gas markets.[28]

Table 2-13 presents the U.S. Department of Energy's annual projections of natural gas production, consumption, and wellhead prices from 1993 to 2010 based on three rates of economic growth. U.S. natural gas production and consumption are projected to increase steadily over the projection period.[29] The range of projections for 2010 is from 19.89 to 21.91 Tcf. According to the IPAA, natural gas production is expected to increase through the year 2000 at an average annual rate of 1.1 percent, reaching nearly 20 Tcf by the year 2000, up from an expected level of 18.3 Tcf in 1993.[30]

TABLE 2-13. SUPPLY, DEMAND, AND PRICE PROJECTIONS FOR NATURAL GAS, 1993-2010

		Alternative projections to 2010		
	Actual 1993	Base case economic growth	High economic growth	Low economic growth
Production (Tcf)	18.35	20.88	21.91	14.89
Consumption (Tcf)	20.21	24.59	25.85	23.18
Wellhead price (1993 $/Mcf)	2.02	3.39	3.74	3.01

Source: U.S. Department of Energy. Annual Energy Outlook 1995. DOE/EIA-0383(95). January 1995.

2.3 PRODUCTION FACILITIES

The following subsections provide details on the operating facilities of the oil and natural gas production industry including production wells, dehydration units, tank batteries, and natural gas processing plants.

2.3.1 Production Wells

Table 2-14 displays the number of crude oil and natural gas wells in operation from 1983 to 1992.[31] In 1992, an estimated 594,200 crude oil wells operated in the United States, and 280,900 natural gas production wells. For offshore production, an estimated 3,841 oil and gas production platforms operated in 1991 and were associated with a total of 33,000 wells. Natural gas production wells have increased in number steadily since 1983, while crude oil wells show more volatility.

TABLE 2-14. NUMBER OF CRUDE OIL AND NATURAL GAS WELLS, 1983-1992

Year	Natural gas producing wells	Crude oil producing wells
1983	170,300	603,300
1984	193,900	620,800
1985	214,100	646,600
1986	219,100	628,700
1987	214,600	621,200
1988	217,800	623,600
1989	232,100	606,900
1990	241,100	602,400
1991	265,100	610,200
1992	280,900	594,200

Source: U.S. Department of Energy. Natural Gas 1992: Issues and Trends. DOE/EIA-0560(92). Washington, DC. March 1993.

Table 2-15 details the distribution of oil and gas well capacity by production of barrels per month.[32] Small production wells dominate the industry. Stripper wells are defined as those production wells that produce less than 10 bpd or 60 Mcf per day. In 1989, over 80 percent of the oil wells produced less than 10 bpd or 0 to 300 barrels per month, and over 78 percent of the gas wells produced within the same range. The remaining production wells produce over a wide range, from levels of 301 barrels per month to over 5,000 barrels per month.

TABLE 2-15. U.S. ONSHORE OIL AND GAS WELL CAPACITY BY SIZE RANGE, 1989

Size range (barrels/ month)	Number of oil wells	Percentage of total	Number of gas wells	Percentage of total
0-60	306,032	49.5	135,231	51.8
61-100	67,150	10.9	24,049	9.2
101-200	76,926	12.4	28,144	10.8
201-300	47,263	7.6	17,765	6.8
301-400	20,631	3.3	10,859	4.2
401-500	21,433	3.5	6,957	2.7
501-600	13,044	2.1	5,442	2.0
601-1000	29,992	4.9	12,400	4.7
1001-2000	22,134	3.6	10,042	4.0
2001-5000	9,735	1.6	6,365	2.4
5001-Over	3,555	0.6	3,806	1.4
Total	617,895	100.0	261,060	100.0

Source: Gruy Engineering Corporation. Estimates of RCRA Reauthorization Economic Impacts on the Petroleum Extraction Industry. Prepared for the American Petroleum Institute. July 20, 1991.

Table 2-16 presents the distribution of U.S. natural gas producing wells by state at the end of 1993.[33] According to World Oil, for 1993, a total of 286,168 natural gas producing wells operated at onshore and offshore locations in the

TABLE 2-16. DISTRIBUTION OF U.S. GAS WELLS BY STATE, 1993

State	1993 gas wells	Percentage of total (%)
Alabama	3,395	1.19
Alaska	157	0.05
Arkansas	2,914	1.02
California	1,072	0.37
Colorado	6,372	2.23
Federal OCS	3,532	1.23
Illinois	384	0.13
Indiana	1,327	0.46
Kansas	14,200	4.96
Kentucky	12,836	4.49
Louisiana	13,214	4.62
Michigan	3,174	1.11
Mississippi	552	0.19
Montana	2,900	1.01
Nebraska	60	0.02
New Mexico	27,832	9.73
New York	5,951	2.08
North Dakota	104	0.04
Ohio	34,581	12.08
Oklahoma	28,902	10.10
Pennsylvania	31,100	10.87
South Dakota	38	0.01
Tennessee	620	0.22
Texas	47,245	16.51
Utah	1,164	0.41
Virginia	1,340	0.47
West Virginia	38,280	13.38
Wyoming	2,880	1.01
Others	42	0.01
Total U.S.	286,168	100.00

Source: Producing Gas Well Numbers are up Once Again. World Oil. February 1993. Vol. 214, No.2.

continental U.S. and Alaska. As shown, Texas accounts for approximately 16.5 percent of U.S. natural gas wells with 47,245. A continued increase in U.S. natural gas wells is expected for 1994 based on increases in gas prices.

2.3.1.1 Gruy Engineering Corporation Database. Based on lease data, the Gruy Engineering Corporation developed "wellgroups" for both oil and gas wells in each of 37 different geographic areas across the United States.[34] For each geographic area, wellgroups are defined by well depth and then by production rate in each depth range. Four depth ranges were employed for oil wells: 0 to 2,000 feet; 2,001 to 6,000 feet; 6,001 to 10,000 feet; and deeper than 10,000 feet. Three depth ranges were developed for gas wells: 0 to 4,000 feet; 4,001 to 10,000 feet; and deeper than 10,000 feet. Furthermore, 11 production ranges were used for both oil and gas wells, expressed in barrels of oil equivalent (BOE), where one barrel of oil equals one BOE that equals 10 Mcf. The production rate ranges in BOE per month are 0 to 60; 61 to 100; 101 to 200; 201 to 300; 301 to 400; 401 to 500; 501 to 600; 601 to 1,000; 1,001 to 2,000; 2,001 to 5,000; and greater than 5,000. Therefore, each of the 37 geographic areas was divided into a possible 44 oil wellgroups and 33 gas wellgroups. The result of Gruy's analysis provides 1,004 oil wellgroups and 643 gas wellgroups (some regions had no wells of certain types). Appendix A provides data on the oil wellgroups developed by Gruy Engineering for each geographic area, and Appendix B provides data on the natural gas wellgroups.

2.3.2 Dehydration Units

The Gas Research Institute (GRI) estimates that the U.S. may have 40,000 or more glycol dehydration units. TEG and EG dehydration units account for approximately 95 percent of this total, with solid desiccant dehydration units accounting for the remaining 5 percent.[35] The primary application of solid desiccant dehydration units is to dehydrate natural gas streams at cryogenic natural gas processing plants.

For TEG dehydration units, stand-alone units dehydrate natural gas from an individual well or several wells, and units are collocated at condensate tank batteries and natural gas processing plants. Available information indicates that, on average, there is one TEG dehydration unit per condensate tank battery and two or four dehydration units (TEG, EG, or solid desiccant) per natural gas processing plant, depending on throughput capacity.[36,37]

2.3.3 Tank Batteries

According to the BID, approximately 94,000 tank batteries operated in the U.S. as of 1989.[38] Furthermore, over 85 percent of tank batteries, or an estimated 81,000 facilities, are classified as black oil tank batteries. The remaining 13,000 tank batteries are classified as condensate tank batteries.

2.3.4 Natural Gas Processing Plants

Table 2-17 shows the number of natural gas processing facilities in operation from 1987 to 1993 in the United States.[39] Over this time period the number of natural gas processing plants has declined by over 10 percent, or a total of 82 plants over 7 years. Table 2-18 provides the number of natural gas processing facilities as of January 1, 1994, the total processing capacity, and 1993 throughput level by State.[40] The States with the largest number of natural gas processing plants are Texas, Oklahoma, Louisiana, Colorado, and Wyoming, while the top states in terms of natural gas processing capacity are Texas, Louisiana, Alaska, Kansas, and Oklahoma.

TABLE 2-17. U.S. NATURAL GAS PROCESSING FACILITIES, 1987-1993

Year	Number of facilities
1987	810
1988	760
1989	745
1990	751
1991	748
1992	735
1993	728

Source: Gas Processing Report. Oil and Gas Journal. 92(24). June 1994.

2.3.5 Natural Gas Transmission and Storage Facilities

There are an estimated 300,000 miles of high-pressure transmission pipelines and approximately 1990 compressor stations in the U.S. In addition, the natural gas industry operates over 300 underground storage sites.

2.4 FIRM CHARACTERISTICS

A regulatory action to reduce pollutant discharges from facilities producing crude oil and natural gas will potentially affect the business entities that own the regulated facilities. In the oil and natural gas production industry, facilities comprise those sites where plant and equipment extract and process extracted streams and recovered products to produce the raw materials crude oil and natural gas. Companies that own these facilities are legal business entities that have the capacity to conduct business transactions and make business decisions that affect the facility.

TABLE 2-18. U.S. NATURAL GAS PROCESSING PLANTS, CAPACITY, AND THROUGHPUT AS OF JANUARY 1, 1994, BY STATE

		Natural gas (MMcfd)	
State	Number of plants	Capacity	1993 throughput
Alabama	9	785.0	700.7
Alaska	3	7,775.0	6,502.0
Arkansas	3	878.0	520.5
California	29	1,044.0	658.5
Colorado	50	1,596.5	1,128.6
Florida	2	890.0	622.0
Kansas	22	5,122.0	3,778.4
Kentucky	3	141.0	117.9
Louisiana	72	18,334.4	11,869.4
Michigan	28	4,731.9	858.6
Mississippi	6	884.2	209.5
Montana	6	19.5	6.8
New Mexico	34	2,889.0	2,122.2
North Dakota	6	122.9	83.2
Ohio	1	20.0	8.8
Oklahoma	94	4,656.8	2,857.5
Pennsylvania	2	14.0	8.3
Texas	293	17,259.5	12,002.5
Utah	14	624.9	416.2
West Virginia	7	398.9	337.9
Wyoming	41	3,783.7	2,973.6
Total U.S.	725	71,971.2	47,783.1

Source: "Worldwide Gas Processing Report." Oil & Gas Journal. 92(24):49110. June 13, 1994.

2.4.1 Ownership

The oil and natural gas industry may be divided into different segments that include producers, transporters, and distributors. The producer segment may be further divided between major and independent producers. Major producers include large oil and gas companies that are involved in each of the five industry activities: (1) exploration, (2) production, (3) transportation, (4) refining, and (5) marketing. Independent producers include smaller firms that are involved in some but not all of the five activities. Transporters are comprised of the pipeline companies, while distributors are comprised of the local distribution companies.

During 1992, almost 7,700 companies owned the 9,391 establishments operating within SIC code 1311 (Crude Oil and Natural Gas).[41] For SIC 1311, the top 8 firms in 1992 accounted for 43.2 percent of the value of shipments, while the top 16 firms accounted for almost 60 percent. Furthermore, the top 8 firms accounted for 64 percent of industry crude oil production and 37 percent of industry natural gas production, while the top 16 firms accounted for 77.7 percent of industry crude oil production and 58.3 percent of industry natural gas production.[42]

Through the mid-1980s, natural gas was a secondary fuel for many producers. However, now it is of primary importance to many producers. The Independent Petroleum Association of America reports that 70 percent of its members' income comes from natural gas production.[43] In 1993, gas production revenues exceeded oil production revenues for the first time, accounting for 56 percent ($38 billion) of total oil and gas industry production revenues. Higher wellhead prices for natural gas, increased efficiency, and lower production costs have all contributed to increased natural gas production and improvements in producer revenues.[44]

2.4.2 Size Distribution

The Small Business Administration (SBA) defines criteria for defining small businesses (firms) in each SIC. Table 2-19 lists the primary SICs to be affected by the proposed

TABLE 2-19. NUMBER AND PROPORTION OF FIRMS IN SMALL BUSINESS CATEGORY (BY SIC CODE)

SIC Code	SIC Description	SBA size standard in number of employees or annual sales	Number of firms	Number of firms meeting SBA standard	Percentage of firms meeting SBA standard
1311	Crude petroleum and natural gas	500	429	372	87%
1381	Drilling oil and gas wells	500	132	100	76%
1382	Oil and gas exploration services	$5 million	176	77	44%
2911	Petroleum refining	1,500	141	98	70%
4922	Natural gas transmission	$5 million	79	11	14%
4923	Gas transmission and distribution	$5 million	74	6	8%
4924	Natural gas distribution	500	121	71	59%

Source: Ward's Business Directory. Volume 2. Washington, DC. 1993.

regulations and their corresponding small business criteria. SICs 1311 and 1381 have the highest percentage of small businesses--87 percent and 76 percent respectively--and SICs 4922 and 4123 have the lowest percentage--8 percent and 14 percent respectively.[45]

2.4.3 Horizontal and Vertical Integration

Because of the existence of major oil companies, the industry possesses a wide dispersion of vertical and horizontal integration. The vertical aspects of a firm's size reflect the extent to which goods and services that can be bought from outside are produced in house, while the horizontal aspect of a firm's size refers to the scale of production in a single-product firm or its scope in a multiproduct one.

Vertical integration is a potentially important dimension in analyzing firm-level impacts because the regulation could affect a vertically integrated firm on more than one level. The regulation may affect companies for whom oil and natural gas production is only one of several processes in which the firm is involved. For example, a company owning oil and natural gas production facilities may ultimately produce final petroleum products, such as motor gasoline, jet fuel, or kerosine. This firm would be considered vertically integrated because it is involved in more than one level of requiring crude oil and natural gas and finished petroleum products. A regulation that increases the cost of oil and natural gas production will ultimately affect the cost of producing final petroleum products.

Horizontal integration is also a potentially important dimension in firm-level analyses for any of the following reasons:

- A horizontally integrated firm may own many facilities of which only some are directly affected by the regulation.
- A horizontally integrated firm may own facilities in unaffected industries. This type of diversification would help mitigate the financial impacts of the regulation.
- A horizontally integrated firm could be indirectly as well as directly affected by the regulation. For example, if a firm is diversified in manufacturing pollution control equipment (an unlikely scenario), the regulation could indirectly and favorably affect it.

In addition to the vertical and horizontal integration that exists among the large firms in the industry, many major producers often diversify within the energy industry and produce a wide array of products unrelated to oil and gas production. As a result, some of the effects of control of oil and gas production can be mitigated if demand for other energy sources moves inversely compared to petroleum product demand.

In the natural gas sector of the industry, vertical integration is limited. Production, transmission, and local distribution of natural gas usually occur at individual firms. It is more likely that natural gas producers will sell their output either to a firm that will subject it to additional purification processes or directly to a pipeline for transport to an end user. Several natural gas firms operate multiple facilities. However, natural gas wells are not exclusive to natural gas firms only. Typically wells produce both oil and gas and can be owned by a natural gas firm or an oil company.

Of the independents' total revenues, 72 percent is derived from natural gas output, and the remaining 28 percent is from crude oil production. Unlike the large integrated firms that have several profit centers such as refining, marketing, and transportation, most independents have to rely only on profits generated at the wellhead from the sale of oil and natural gas. Overall, the independent producers sell their output to refineries or natural gas pipeline companies. They are typically not vertically integrated but may own one or two facilities, indicating limited horizontal integration.

2.4.4 Performance and Financial Status

In a special addition of the Oil and Gas Journal (OGJ), financial and operating results for the top 300 oil and natural gas companies are reported.[46] Table 2-20 lists selected statistics for the top 20 companies in 1993.[47] The results presented in the table reflect lower crude oil and petroleum prices in 1993, which suppressed revenues. However,

TABLE 2-20. TOP 20 OIL AND NATURAL GAS COMPANIES, 1993

Rank	Company	Total assets ($\$10^3$)	Total revenue ($\$10^3$)	Net income ($\$10^3$)	Worldwide liquids production (Mil bbl)	Worldwide natural gas production (Bcf)	U.S. liquids production (Mil bbl)	U.S. natural gas production (Mil bbl)
1	Exxon Corp.	84,145,000	111,211,000	5,280,000	568.0	1,583.0	202.0	697.0
2	Mobil Corp.	40,585,000	63,975,000	2,084,000	285.0	1,665.0	111.0	558.0
3	Chevron Corp.	34,736,000	37,082,000	1,265,000	295.0	902.0	144.0	751.0
4	Amoco Corp.	28,486,000	28,617,000	1,820,000	236.0	1,487.0	100.0	867.0
5	Shell Oil Co.	26,851,000	21,092,000	781,000	170.0	553.0	147.0	539.0
6	Texaco Inc.	26,626,000	34,071,000	1,068,000	228.0	748.0	155.0	652.0
7	ARCO (Atlantic Richfield Corp.)	23,894,000	19,183,000	269,000	250.0	449.0	221.0	332.0
8	Occidental Petroleum Corp.	17,123,000	8,544,000	283,000	79.0	238.0	21.0	219.0
9	BP (USA)	14,864,000	15,714,000	1,461,000	--	--	228.9	33.6
10	Conoco Inc.	11,938,000	15,771,000	812,000	135.0	481.0	40.0	305.0
11	Enron Corp.	11,504,315	8,003,939	332,522	3.5	262.2	2.5	240.0
12	Phillips Petroleum Co.	10,868,000	12,545,000	243,000	89.0	509.0	47.0	345.0
13	USX-Marathon Group	10,806,000	11,962,000	-29,000	57.0	317.0	41.0	193.0
14	Coastal Corp.	10,277,100	10,136,100	115,800	4.9	122.0	4.9	122.0
15	Unocal Corp.	9,254,000	8,344,000	213,000	84.0	623.0	48.0	365.0
16	Amerada Hess Corp.	8,641,546	5,872,741	-268,203	79.0	323.0	26.0	183.0
17	Columbia Gas System	6,957,900	3,398,500	152,200	3.6	71.5	3.6	71.5
18	Ashland Oil Inc.	5,551,817	10,283,325	142,234	8.3	36.2	0.4	36.2
19	Consolidated Natural Gas Co.	5,409,586	3,194,616	205,916	3.9	124.0	3.9	124.0
20	Pennzoil Co.	4,886,203	2,782,397	141,856	24.0	223.0	24.0	220.0

Note: All values are in 1993 U.S. dollars.

Source: "Total Earnings Rose, Revenues Fell in 1993 for OGJ300 Companies." Oil and Gas Journal. 92(36):49-75. September 5, 1994.

higher natural gas prices, consumption, and production, as well as increased consumption of petroleum production, offset these trends. Total assets for the top 300 companies fell in 1993 for the third consecutive year, a reflection of continued industry restructuring and consolidation with mergers, acquisitions, and liquidations. As a result, the number of publicly held companies was slashed. The top 300 companies, however, represent a large portion of the U.S. oil and gas industry and indicate changes and trends in industry activity and operating performance.

Net income for OGJ's top 300 companies jumped 75.5 percent in 1993 to $18.3 billion, while total revenues fell 3.9 percent to $475.1 billion. Other measures of financial performance for the group showed improvement in 1993. Capital and exploration spending totaled $50.3 billion, up 1.8 percent from 1992. In addition, the number of U.S. net wells drilled rose 24.4 percent to 8,656. Table 2-21 provides 1993 performance highlights for the OGJ's group of 22 large U.S. oil companies.[48] Earnings for the group jumped sharply in 1993, increasing by 78.6 percent from 1992. Performance in 1993 restored group profits to the 1991 level even though total revenues for the group fell 3.8 percent to $436.3 billion in 1993. Lower crude oil and petroleum product prices were the main factors in the observed decline in revenues.

A more recent issue of OGJ reported on the economic status of all 110 major and nonmajor* natural gas pipeline companies in 1994.[49] Table 2-22 reports the sales volume, operating revenues, and net income for the top 10 U.S. natural gas pipeline companies in 1994. Operating revenues of the top

*Major pipeline companies are those whose combined gas sold for resale and gas transported for a fee exceeded 50 bcf at 14.37 psi (60 degrees F) in each of the three previous calendar years. Nonmajors are natural gas pipeline companies not classified as majors and whose total gas sales of volume transactions exceeded 200 MMcf at 14.73 psi (60 degrees F) in each of the three previous calendar years.

TABLE 2-21. PERFORMANCE MEASURES FOR OGJ GROUP, 1993

Performance measure	1993 highlights
Total assets	$385.4 billion, down 1 percent
Net profits	$16.2 billion, up 78.6 percent
Return on equity	10.1 percent, up 4.8 points
Return on total assets	3.9 percent, up 1.9 points
Capital/exploration spending	$38.8 billion, down 5.8 percent
Net liquids production	8.4 million bpd, down 2 percent
Net natural gas production	30 bcfd, up 0.7 percent
Crude runs to stills	15.6 million bpd, up 1.2 percent
Liquid reserves	32 billion bbl, up 1.7 percent
Natural gas reserves	140.2 tcf, up 0.6 percent

Source: "Profits for OGJ Group Show Big Gain in 1993; Revenues Dip." Oil and Gas Journal. 92(24):25-30. June 13, 1994.

TABLE 2-22. PERFORMANCE OF TOP 10[a] GAS PIPELINE COMPANIES, 1994

Company	Net Income ($000)	Operating Revenues ($000)
Tennessee Gas Pipeline Co.	489,984	1,065,285
Natural Gas Pipeline of America	158,165	1,046,660
ANR Pipeline Co.	152,057	152,057
Texas Eastern Transmission Corp.	148,887	832,405
Panhandle Eastern Pipe Line Co.	112,910	384,771
Transcontinental Gas Pipe Line Corp.	110,726	1,590,962
Northern Natural Gas Co.	97,570	702,567
El Paso Natural Gas Co.	92,978	669,439
CNG Transmission Corp.	88,055	488,754
Florida Gas Transmission Co.	78,166	175,731
Total 1994	1,529,498	7,108,631
Total All Companies 1994	2,373,245	16,547,531
Total All Companies 1993	1,113,303	21,746,475

[a]Based on net income.

Source: "U.S. Interstate Pipelines Ran More Efficiently in 1994". Oil and Gas Journal, p. 39-58. November 27, 1995.

10 companies equaled $7,108,631 and represented 43 percent of the total operating revenues for major and nonmajor companies, which had declined by 24 percent from the previous year. Net income for the top 10 was over $1.5 billion and represented almost 65 percent of the total net income for all major and nonmajor companies. Despite the overall decline in operating revenues, the total net income for the 100 companies rose by 37 percent from 1993 to 1994.

References:

1. U.S. Environmental Protection Agency. Natural Emission Standards for Hazardous Air Pollutants for Source Categories: Oil and Natural Gas Production and Natural Gas Transmission and Storage—-Background Information for Proposed Standards. Office of Air Quality Planning and Standards. Research Triangle Park, NC. July 1996.

2. Ref. 1, p. 2-6.

3. Ref. 1, p. 2-6.

4. Wright Killen & Co. Natural Gas Dehydration: Status and Trends. January 1994. Prepared for Gas Research Institute. Chicago, IL.

5. Ref. 1, p. 2-13 through 2-15.

6. U.S. Department of Energy. Energy Information Administration. U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves: 1993 Annual Report. October 1994.

7. Ref. 6.

8. Ref. 6.

9. U.S. Department of Energy. Petroleum Supply Annual 1992. DOE/EIA-0340(92)-1. Vol. 1. May 1993.

10. Ref. 9.

11. U.S. Department of Energy. Natural Gas Annual 1991. DOE/EIA-0131(91). Washington, DC. October 1992.

12. U.S. Department of Energy. Annual Energy Review 1991. DOE/EIA-0384(91). June 1992.

13. Independent Petroleum Association of America. Fact Sheet. "IPAA Supply and Demand Committee Short Run Forecast for 1993."

14. Independent Petroleum Association of America. Fact Sheet. "IPAA Supply and Demand Committee Long Run Forecast for 1993-2000." May 6, 1993.

15. Ref. 6.

16. Ref. 14.

17. Ref. 6.

18. Ref. 6.

19. Ref. 9.

20. Ref. 11.

21. Ref. 9.

22. Ref. 11.

23. Doane, Michael J., and Spulber, Daniel F. "Open Access and the Evolution of the U.S. Spot Market for Natural Gas." Journal of Law and Economics. 37:477-517. October 1994.

24. Energy Statistics Sourcebook, 8th ed. PennWell Publishing Co. September 1993.

25. Ref. 24.

26. U.S. Department of Energy. Energy Information Administration. Natural Gas Monthly U.S. Natural Gas Imports and Exports--1993. August 1994.

27. U.S. Department of Energy. Natural Gas 1994: Issues and Trends. DOE/EIA-0560(94). Energy Information Administration. Washington, DC. July 1994.

28. Haun, Rick R. U.S. Gas Processing Prospects to Improve After Mid-90s. Oil and Gas Journal. 91(23).

29. Ref. 6.

30. Ref. 14.

31. U.S. Department of Energy. Natural Gas 1992: Issues and Trends. DOE/EIA-0560(92). Washington, DC. March 1993.

32. Gruy Engineering Corporation. Estimates of RCRA Reauthorization Economic Impacts on the Petroleum Extraction Industry. Prepared for the American Petroleum Institute. July 20, 1991.

33. "Producing Gas Well Numbers Still Climbing," World Oil. 215(2):77, February 1994.

34. Ref. 32.

35. Ref. 4, Table B-1.

36. Memorandum from Akin, Tom, EC/R Incorporated to Smith, Martha E., EPA/CPB. July 30, 1993. Revised preliminary estimate of the number and size ranges of tank batteries on a national basis.

37. Memorandum from Viconovic, George, EC/R Incorporated, to Smith, Martha E., EPA/CPB. April 8, 1993. Summary of meeting with the Gas Research Institute.

38. Ref. 1, p. 2-3.

39. "Worldwide Gas Processing Report." Oil and Gas Journal. 92(24):49-110. June 13, 1994.

40. Ref. 39.

41. U.S. Department of Commerce. Census of Mineral Industries-Industry Series. Bureau of the Census, Washington, DC. 1995. Table 1.

42. Ref. 41, Table 10.

43. Ref. 27.

44. Ref. 27.

45. Ward's Business Directory. Volume 2. Washington, DC. 1993.

46. "Total Earnings Rose, Revenues Fell in 1993 for OGJ300 Companies." Oil and Gas Journal. 92(36):49-75. September 5, 1994.

47. Ref. 27.

48. "Profits for OGJ Group Show Big Gain in 1993; Revenues Dip." Oil and Gas Journal. 92(24):25-30. June 13, 1994.

49. "U.S. Interstate Pipelines Ran More Efficiently in 1994." Oil and Gas Journal. November 27, 1995. p. 39-58.

SECTION 3
REGULATORY CONTROL OPTIONS AND COSTS OF COMPLIANCE

The BID details the available technologies on which this NESHAP is based. Model plants were developed to evaluate the effects of various control options on the oil and natural gas production and natural gas transmission and storage source categories. Control options were selected based on the application of presently available control equipment and technologies and varying levels of capture consistent with different levels of overall control. Section 3.1 presents a brief description of the model plants. Section 3.2 provides an overview of the control options, and Section 3.3 summarizes the compliance costs associated with the regulatory control options.

3.1 MODEL PLANTS

The large number of production, processing, and storage facilities in the oil and natural gas industry necessitates using model plants to simulate the effects of applying the regulatory control options to this industry. A model plant does not represent any single actual facility; rather it represents a range of facilities with similar characteristics that may be affected by the regulation. Each model plant is characterized by facility type, size, and other parameters that influence the estimates of emissions and control costs. Model plants developed for the oil and natural gas production and natural gas transmission and storage source categories are

- TEG dehydration units,

- tank batteries that handle condensate (CTB),
- natural gas processing plants (NGPP), and
- offshore production platforms (OPP).

The following subsections identify these model plants and provide the estimated capacity, throughput, and population for each unit.*

3.1.1 TEG Dehydration Units

As shown in Table 3-1, the engineering analysis establishes five model TEG dehydration units based on natural gas throughput capacity.[1] These model units are defined in the following manner:

- TEG unit A: $\leq$5 MMcfd,
- TEG unit B: >5 MMcfd and $\leq$20 MMcfd,
- TEG unit C: >20 MMcfd and $\leq$50 MMcfd,
- TEG unit D: >50 to 500 Mmcfd, and
- TEG unit E: >500 Mmcfd.

The total estimated number of TEG dehydration units is just below 30,000 units. In addition, Table 3-1 includes the number of TEG dehydration units by application (i.e., stand-alone, condensate tank battery, natural gas processing plant, offshore production platform, and natural gas transmission and storage facilities). The estimated number of TEG dehydration units by application is assumed to be one TEG dehydration unit per condensate tank battery and offshore production platform used in the separation of the well stream and two to four dehydration units (TEG, EG, or solid desiccant) per natural gas processing plant, depending on throughput capacity and type of processing configuration, to dry the gas to required specifications. In addition, model TEG units were distributed within the natural gas transmission and storage source

---

*No model plants are developed for natural gas transmission and storage facilities because the only HAP emission point of concern for these facilities is a process vent at an associated TEG dehydration unit.

category consistent with their natural gas design and throughput capacities.

TABLE 3-1. MODEL TEG DEHYDRATION UNITS

	Model plant					
	A	B	C	D	E	Total
Capacity (MMcfd)	<5	5 to 20	20 to 50	>50 to 500	>500	
Throughput (MMcfd)	0.3	10	35	100	500	
Estimated population						
Stand-alone	24,000	200	25	20		24,245
@ Condensate tank battery	12,000	500	100	70		12,670
@ Natural gas processing plant		66	110	54		230
@ Offshore production platform		260	40			300
@ Natural gas transmission and underground storage	200	125	35	10	10	370
TOTAL	36,200	1,151	300	154	10	37,815

Source: National Emission Standards for Hazardous Air Pollutants for Source Categories: Oil and Natural Gas Production and Natural Gas Transmission and Storage —-Background Information Document. U.S. Environmental Protection Agency. Research Triangle Park, NC. April 1997.

Note: MMcfd = million cubic feet per day.

3.1.2 Condensate Tank Batteries

As shown in Table 3-2, the engineering analysis establishes four model condensate tank batteries based on natural gas throughput capacity. These model units are defined as follows:

- CTB E: ≤5 MMcfd,
- CTB F: >5 MMcfd and ≤20 MMcfd,
- CTB G: >20 MMcfd and ≤50 MMcfd, and
- CTB H: >50 MMcfd.

TABLE 3-2. MODEL CONDENSATE TANK BATTERIES

	Model plant				Total
	E	F	G	H	
Capacity (MMcfd)	≤5	5 to 20	20 to 50	>50	
Throughput (MMcfd)	1	10	35	100	
Estimated population	12,000	500	100	70	12,670

Source: National Emission Standards for Hazardous Air Pollutants for Source Categories: Oil and Natural Gas Production and Natural Gas Transmission and Storage —-Background Information Document. U.S. Environmental Protection Agency. Research Triangle Park, NC. April 1997.

Note: Mmcfd = million cubic feet per day.

Condensate tank batteries generally have a TEG dehydration unit as a process unit within the overall system design of the tank battery. The estimated number of condensate tank batteries operating in the U.S. is close to 13,000, or 15 percent of all tank batteries.[2]

3.1.3 Natural Gas Processing Plants

As shown in Table 3-3, the engineering analysis establishes three model natural gas processing plants based on natural gas throughput capacity. These model units are defined as follows:

- NGPP A: ≤20 MMcfd,
- NGPP B: >20 MMcfd and ≤100 MMcfd,
- NGPP C: >100 MMcfd.

Although the population of TEGs and tank batteries must be estimated, the OGJ provides detailed information on U.S. natural gas processing plants. As of January 1, 1994, the U.S. had approximately 700 natural gas processing plants. The OGJ's annual survey of natural gas processing plants

TABLE 3-3. MODEL NATURAL GAS PROCESSING PLANTS

	Model plant			
	A	B	C	Total
Capacity (MMcfd)	≤20	20 to 100	>100	
Throughput (Mmcfd)	10	70	200	
Estimated population	260	300	140	700

Source: U.S. Environmental Protection Agency. National Emission Standards for Hazardous Air Pollutants for Source Categories: Oil and Natural Gas Production and Natural Gas Transmission and Storage—-Background Information Document. Office of Air Quality Planning and Standards. Research Triangle Park, NC. April 1997.

Note: MMcfd = million cubic feet per day.

identifies each plant by State, design capacities, and estimated 1993 throughput.[3] The estimates of the number of natural gas processing plants corresponding to each size range shown in Table 3-3 are based on this annual survey.

3.1.4 Offshore Production Platforms

As shown in Table 3-4, the engineering analysis establishes two model offshore production platforms based on crude oil productive capacity of those located in state water areas. These model units are defined in the following manner:

- OPP A: State water areas with 1,000 bpd capacity, and
- OPP B: State water areas with 5,000 bpd capacity.

As discussed in the BID, approximately 300 offshore production platforms are located in State water and therefore subject to EPA's jurisdiction for air emissions regulations. The model characterization of these platforms is based on data from the Minerals Management Service (MMS) of the U.S. Department of Interior.[4]

TABLE 3-4. MODEL OFFSHORE PRODUCTION PLATFORMS

	Model plant		
	Small	Medium	Total
Location	State waters	State waters	
Capacity (BOPD)	1,000	5,000	
Throughput (BOPD)	200	2,000	
Estimated population	260	40	300

Source: National Emission Standards for Hazardous Air Pollutants for Source Categories: Oil and Natural Gas Production and Natural Gas Transmission and Storage —-Background Information Document. U.S. Environmental Protection Agency. Research Triangle Park, NC. April 1997.

Note: BOPD = barrels of oil per day.

3.2 CONTROL OPTIONS

Sources of HAP emissions in oil and natural gas production include the glycol dehydration unit process vents, storage vessels, and equipment leaks. Table 3-5 summarizes the control options under evaluation for HAP emission points within the model units in the oil and natural gas production and natural gas transmission and storage source categories.[5] The control options include the use of certain equipment (e.g., installation of a cover or fixed roof for tanks) and work standards (e.g., leak detection and repair [LDAR] programs for fugitive emission sources). Control options that are applicable to each potential HAP emission point at model plants are fully detailed in the BID.

Major sources of HAP emissions are controlled based on the MACT floor, as defined by the control options in Table 3-6. The Agency has determined that a glycol dehydration unit must be collocated at a facility for the facility to be designated as a major source. Therefore, the MACT floor may apply to stand-alone TEG units, condensate tank

TABLE 3-5. SUMMARY OF CONTROL OPTIONS BY MODEL PLANT AND HAP EMISSION POINT

Model plant/unit	HAP emission point	Control option	Control efficiency (%)
TEG dehydration unit	Reboiler vent	Condenser with flash tank in design	95
		Condenser without flash tank	50
		Combustion	98
		System optimization	Variable
Tank battery	Open-top storage tank	Cover and vent to 95% control device or redirect	99
	Fixed roof storage tank	Vent to 95% control device or redirect	95
	Equipment leaks	LDAR[a]	70
Natural gas processing plant	Fixed roof storage tank	Vapor collection and redirect	95
	Equipment leaks	LDAR	70
Offshore production platforms	Equipment leaks	LDAR	70

[a] Leak detection and repair program based on one of the following:

- Control Techniques Guideline (CTG) document applicable to natural gas/gasoline processing plants,
- New Source Performance Standard (NSPS) applicable to onshore natural gas processing plants constructed or modified after 1/20/84, or
- Hazardous Organic NESHAP (HON) regulatory negotiation applicable to synthetic organic chemical manufacturing facilities.

Source: National Emission Standards for Hazardous Air Pollutants for Source Categories: Oil and Natural Gas Production and Natural Gas Transmission and Storage —-Background Information Document. U.S. Environmental Protection Agency. Research Triangle Park, NC. April 1997.

batteries, natural gas processing plants, and storage facilities. Black oil tank batteries and offshore production platforms are not considered since TEG units are not typical of the operations at black oil tank batteries and are completely controlled at offshore production platforms.

The engineering analysis contained in the BID document projects the number of major sources of HAP emissions by model plant. Tables 3-6, 3-7, and 3-8 provide the percentage and number of affected units by model type--TEG dehydration unit, condensate tank battery, and natural gas processing plant.

TABLE 3-6. TOTAL AND AFFECTED POPULATION OF TEG UNITS BY MODEL TYPE

	Model TEG Unit					
Item	A	B	C	D	E	Total
Total population	36,200	1,151	300	154	10	37,615
Percent affected	0.0%	22.7%	50.3%	18.2%	50.0%	445
Affected units						
Stand-alone	0	138	25	20	0	183
@ Condensate TB	0	109	100	5	0	214
@ NGPP	0	14	26	3	0	43
@ transmission and storage facility	0	0	0	4	3	5
Total	0	261	151	32	3	445

3.3 COSTS OF CONTROLS

The BID describes in detail the cost estimates for control options that are applicable to each potential HAP emission point at model plants. Cost estimates are expressed

TABLE 3-7. TOTAL AND AFFECTED POPULATION OF CONDENSATE TANK BATTERIES BY MODEL TYPE

	Model condensate tank battery				
Item	E	F	G	H	Total
Total population	12,000	500	100	70	12,670
Percent affected	0%	21.8%	10.0%	7.1%	1.0%
Affected units	0	109	10	5	124

TABLE 3-8. TOTAL AND AFFECTED POPULATION OF NATURAL GAS PROCESSING PLANTS BY MODEL TYPE

	Model NGPP			
Item	A	B	C	Total
Total population	260	300	140	700
Percent affected	2.7%	1.3%	0.7%	1.7%
Affected units	7	4	1	12

in July 1993 dollars. Table 3-9 summarizes the total and annualized capital costs; operating expenses; monitoring, inspection, recordkeeping, and reporting costs (maintenance costs); and total annual cost for each control option by model plant. The annualized capital cost is calculated using a capital recovery factor of 0.1098 based on an equipment life

TABLE 3-9. REGULATORY CONTROL COSTS PER UNIT FOR THE OIL AND NATURAL GAS PRODUCTION INDUSTRY BY MODEL PLANT

Control option/model plant[a]	Number of Affected Units	Total capital cost	Annualized capital cost	Operating and maintenance cost[b]	Total annual cost	Product recovery credit
Condenser control systems[c]						
TEG-B	157	$13,620	$1,495	$11,626	$13,121	$2,825
TEG-B′	104	$11,400	$1,252	$11,538	$12,790	$2,825
TEG-C	67	$13,620	$1,495	$11,626	$13,121	$9,789
TEG-C′	84	$11,400	$1,252	$11,538	$12,790	$9,789
TEG-D	28	$11,400	$1,252	$11,538	$12,790	$23,783
TEG-E	5	$11,400	$1,252	$11,538	$12,790	$3,580
Storage tank controls/recycle						
CTB-F	50	$3,590	$394	$2,511	$2,905	$71
CTB-G	4	$3,590	$394	$2,511	$2,905	$93
CTB-H	2	$3,590	$394	$2,511	$2,905	$115
NGPP-A	3	$3,590	$394	$2,511	$2,905	$115
NGPP-B	2	$3,590	$394	$2,511	$2,905	$115
NGPP-C	0	$3,590	$394	$2,511	$2,905	$115
Storage tank controls/fuel substitute						
CTB-F	50	$3,590	$394	$2,511	$2,905	$46
CTB-G	4	$3,590	$394	$2,511	$2,905	$60
CTB-H	2	$3,590	$394	$2,511	$2,905	$75
NGPP-A	3	$3,590	$394	$2,511	$2,905	$75
NGPP-B	2	$3,590	$394	$2,511	$2,905	$75
NGPP-C	1	$3,590	$394	$2,511	$2,905	$75

(continued)

TABLE 3-9. REGULATORY CONTROL COSTS PER UNIT FOR THE OIL AND NATURAL GAS PRODUCTION INDUSTRY BY MODEL PLANT (CONTINUED)

Control option/model plant[a]	Number of Affected Units	Total capital cost	Annualized capital cost	Operating and maintenance cost[b]	Total annual cost	Product recovery credit
Storage tank controls/flare						
TB-F	9	$37,080	$4,071	$44,490	$48,561	$0
TB-G	2	$37,080	$4,071	$44,490	$48,561	$0
TB-H	1	$45,260	$4,970	$44,817	$49,787	$0
NGPP-A	1	$37,080	$4,071	$44,490	$48,561	$0
NGPP-B	0	$37,080	$4,071	$44,490	$48,561	$0
NGPP-C	0	$45,260	$4,970	$44,817	$49,787	$0
Leak detection and repair						
NGPP-A	7	$1,378	$6,564	$10,543	$11,921	$135
NGPP-B	4	$1,378	$6,564	$19,479	$20,857	$340
NGPP-C	1	$1,378	$6,564	$40,331	$41,709	$815

[a] Abbreviations are TEG for triethylene glycol dehydration units, CTB for condensate tank batteries, and NGPP for natural gas processing plants. The letter following the hyphen designates the model plant.

[b] Included in this cost category are operating and maintenance costs, other annual costs (i.e., administrative, taxes, insurance, etc.), and monitoring, inspection, recordkeeping, and reporting costs.

[c] Model condensate tank battery E is not listed since it does not incur control costs. Also the presence of a flash tank at glycol dehydration units affects the compliance costs. Thus, model TEG-B represents a glycol dehydration unit without a flash tank, white model TEG-B' has a flash tank.

of 15 years and a 7 percent discount rate.[6] The total annual cost is calculated as the sum of the annualized capital cost; operating expenses; and the monitoring, inspection, recordkeeping, and reporting costs.

In addition, product recovery is presented in Table 3-9 as an annual cost credit where applicable. Product recovery credits were calculated by multiplying the mass of product recovered by the product value. Recovered liquid, condensate, and crude oil were assigned a value of $18 per barrel, while recovered gas product was assigned different dollar amounts depending on its use. Recycled product for further processing and sale was valued at $2 per Mcf, recovered gas hydrocarbons for use as a fuel supplement were valued at $1.30 per Mcf, and gas hydrocarbons directed to an incinerator or flare were assigned no value.[7]

Table 3-10 summarizes the annual control costs for major sources expressed per model plant. The annual costs for model condensate tank batteries and natural gas processing plants are appropriately weighted given the percentage of affected units subject to the various control options and include the costs of TEG dehydration units present at each model type. One TEG unit is assigned to each model CTB based on throughput capacity so that a TEG unit A is assigned to each CTB E, a TEG unit B is assigned to each CTB F, a TEG unit C is assigned to each CTB G, and a TEG unit D is assigned to each CTB H. The allocation of TEG units to model NGPPs is such that a model NGPP A is assigned two TEG B units, a model NGPP B is assigned three model TEG C units, and a model NGPP C is assigned three model TEG D units.

TABLE 3-10. SUMMARY OF ANNUAL CONTROL COSTS BY MODEL PLANT

Model Plant	Cost per model unit
TEG dehydration units	
TEG-A	—
TEG-B	$12,989
TEG-C	$12,937
TEG-D	$12,790
TEG-E	$12,790
Condensate tank batteries	
CTB-E	—
CTB-F	$19,660
CTB-G	$24,973
CTB-H	$25,071
Natural gas processing plants	
NGPP-A	$46,747
NGPP-B	$61,823
NGPP-C	$81,083
Natural gas transmission and storage	
TEG-A	-
TEG-B	-
TEG-C	-
TEG-D	$49,787*
TEG-E	$49,787

* Three of the four affected TEGs of this size are assumed to have control costs of $49,787, while the fourth TEG is assumed to have control costs of $4,315.

References:

1. Ref. 1, Chapter 4.

2. Ref. 1, p. 2-4.

3. Ref. 39.

4. U.S. Department of the Interior/Minerals Management Service. Federal Offshore Statistics: 1993 (OCS Report MMS 94-0060). Herndon, VA. 1994.

5. Ref. 1, Table 3-1.

6. Ref. 1.

7. Ref. 1.

SECTION 4
ECONOMIC IMPACT ANALYSIS

Implementing the controls will directly affect the costs of production in the oil and natural gas production industry. However, these initial effects will be felt throughout the economy--downstream by consumers of refined petroleum products and natural gas and upstream by suppliers of inputs to the industry. As demonstrated in Section 3, facilities in this industry will be affected by the regulation differently, depending on the products (crude oil, condensates, natural gas) they process, the processing equipment they currently employ, and the level of throughput. Facility-level production responses to the additional regulatory costs will determine the market-level impacts of the regulation. Specifically, the cost of the air pollution controls may force the premature closing of some facilities or may cause facilities to alter current production levels.

Section 3 indicates that black oil tank batteries will not incur control costs as a result of the regulation. Thus, only condensates processed at condensate tank batteries will be directly affected by the regulation, which represents less than 5 percent of total U.S. crude oil production.[1] Crude oil is an international commodity, transported and consumed throughout the world. Most economic models of world crude oil markets consider the OPEC as a price-setting residual supplier, facing a net demand for crude oil that is the difference between the world demand and the non-OPEC supply of crude oil.[2,3] Accordingly, the U.S. may be seen as a price taker on the world oil market with no power to influence the world price in any significant way. This analysis does not include a model to assess the regulatory effects on the world crude oil market because not only will less than 5 percent of U.S. crude oil production be affected but changes in the U.S. supply are not likely to influence world prices. Therefore, this analysis focuses on the regulatory effects on the U.S. natural gas market.

As discussed in Section 2, the natural gas industry has undergone fundamental changes in recent years including a restructuring of the interstate pipeline industry and a diminishing of excess productive capacity. These changes have resulted in increased competition within the natural gas industry. Accordingly, producers of natural gas can respond to changes in demand and price levels fairly easily because their product is often sold directly to the end user.

Open access to pipeline transportation created regional spot markets for natural gas through local and regional competition between pipelines for gas supplies and between producers for gas sales. Doane and Spulber find that open access, or the "unbundling" of pipeline services, has integrated regional wellhead markets into a national market for natural gas.[4] The regional wellhead markets are linked by the action of buyers, who are interested in the delivered price of natural gas (i.e., the sum of the wellhead price and the transportation and transaction costs of obtaining gas). Buyers have the opportunity to evaluate costs of purchasing gas from different regions and transporting it along different pipeline systems. To the extent that natural gas producers compete across regions to supply the same customers, the regional wellhead markets combine to form a national market.[5] Based on this research, the U.S. market for natural gas was modeled as a national, perfectly competitive market for a homogeneous commodity.

Sections 4.1 through 4.3.2.2 assesses the market-,and industry-level impact of the regulation on the natural gas production industry. These sections provide a conceptual overview of the production relationships involving the natural gas industry, the details of an operational market model to assess the regulation, and the results of the economic analysis. Section 4.3.2.2 presents a screening analysis of impacts on the natural gas transmission and storage industry. Section 4.4 provides conclusions for the impacts on society from these regulations.

4.1 MODELING MARKET ADJUSTMENTS

Standard concepts in microeconomics are employed to model the supply of natural gas and the impacts of the regulation on production costs and output decisions. The following subsections examine the impact of the regulations that affect operating costs for producing wells in the U.S. natural gas industry. Together they provide an overview of the basic economic theory of the effect that regulations have on production decisions and of the concomitant effect on natural gas prices. The three main elements are the regulatory effects on the production well or "facility," market response, and facility-market interactions.

4.1.1 Facility-Level Effects

At any point in time, the costs that a firm faces can be classified as either unavoidable (sunk) or avoidable. In the former category, we include costs to which the firm is committed and that must be paid regardless of any future actions of the firm.* The second category, avoidable costs, describes any costs that would be foregone by ceasing production. Avoidable costs can also be viewed as the full opportunity costs of operating the facility. These costs can

*For instance, debt incurred to construct a production well or processing facility must be repaid regardless of the production plan and even if the well or facility ceases operation prior to full repayment.

be further refined to distinguish between costs that vary with the level of production and those that are independent of the production level.* The determination of both the avoidability and the variability of firms' costs is essential to analyzing economic responses to the regulation.

Figure 4-1 illustrates the classical U-shaped structure of production costs with respect to natural gas production. Let ATAC be the average total (avoidable) cost curve and MC the marginal cost of producing natural gas, which intersects ATAC at its minimum point. All these curves are drawn conditional on input prices and the technology in place at the production well. Thus, all firms have some flexibility via their decision to operate, at a given output rate, or to close the well. But they do not have the full flexibility to vary the size and composition of their existing capital stock at the production well or processing facility (i.e., to change technology beyond that needed to comply with the regulatory alternative).

The well's supply function for natural gas is that section of the marginal cost curve bounded by the quantities Q_{min} and Q_{max}. Q_{max} is the largest feasible production rate that can be sustained at the facility given the technology and other fixed factors in place, regardless of the output price. Q_{min} is the minimum economically feasible production rate, which is determined by the minimum of the ATAC curve, which coincides with the price P_{min}. Suppose the market price of

*For example, production factors such as labor, materials, and capital (except in the short run) vary with the level of output, whereas expenditures for facility security and administration may be independent of production levels but avoidable if the well or processing facility closes down.

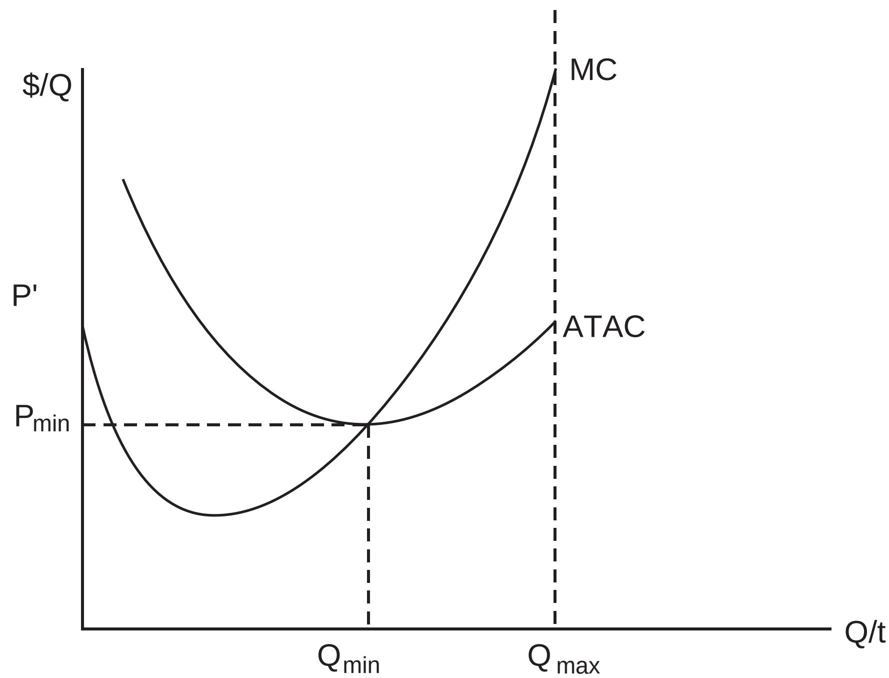


Figure 4-1. Facility unit cost functions.

natural gas is less than P_{min}. In this case, the firm’s best response is to close the well and not produce natural gas because P < ATAC implies that total revenue would be less than total avoidable costs if the well operated at the associated output levels below Q_{min}.*

Now consider the effect of the regulatory control costs. These costs are all avoidable because a firm can choose to cease operation of the facility and thus avoid incurring the costs of compliance. These costs of compliance include the variable component consisting of the operating and maintenance costs and the nonvariable component consisting of the compliance capital equipment acquired for the regulatory option. Incorporating the regulatory control costs will

*This characterization of the economics regarding the operating decision agrees with that described in Reference 6.

involve shifting upward the ATAC and MC curves as shown in Figure 4-2 by the per-unit compliance cost (operating and

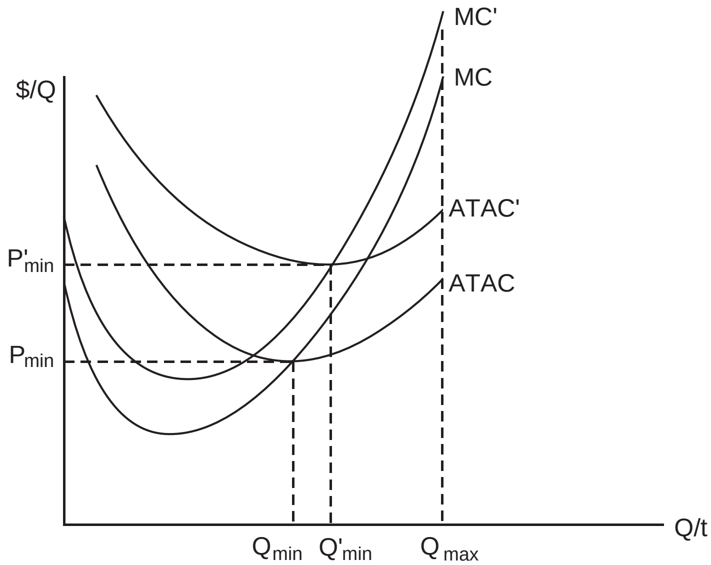


Figure 4-2. Effect of compliance costs on facility cost functions.

maintenance plus annualized capital). Therefore, the supply curve for each production well shifts upward with marginal costs, and a new (higher) minimum operating level (Q'_{min}) is determined by a new (higher) P'_{min}.

4.1.2 Market-Level Effects

The competitive structure of the market is an important determinant of the regulation's effect on market price and quantity. As discussed above, it was assumed that natural gas prices are determined in perfectly competitive markets. As illustrated in Figure 4-3, without the regulation, the market quantity and price of natural gas (Q_0, P_0) are determined by the intersection of the market demand curve (D) and the market supply curve (S). The market supply curve is determined by the horizontal summation of the individual facility supply curves. Imposing the regulation increases the costs of producing natural gas for individual suppliers and, thus, shifts the market supply function upward to S' (see Figure 4-3). The supply shifts for natural gas cause the

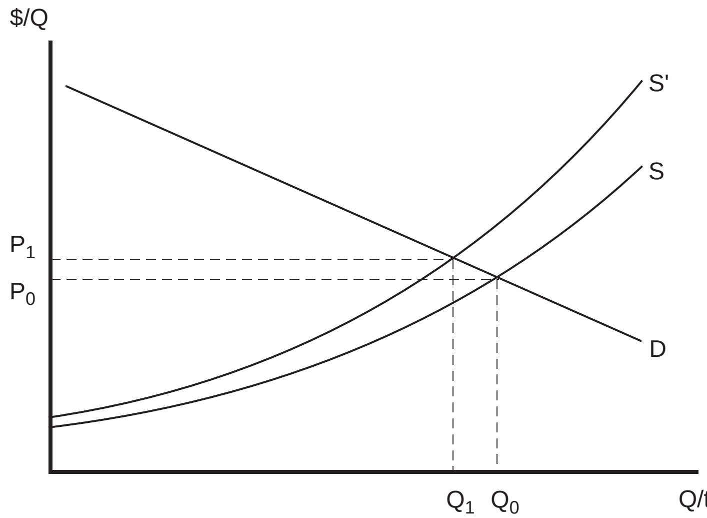


Figure 4-3. Natural gas market equilibria with and without compliance costs.

market price to rise and market quantity to fall at the new with-regulation equilibrium.

4.1.3 Facility-Level Response to Control Costs and New Market Prices

In evaluating the market effects for natural gas, the analysis must distinguish between the initial effect of the regulation and the net effect after the market has adjusted. Initially, the cost curves at all affected wells producing natural gas shift upward by the amount of the appropriate unit costs of the regulation. However, the combined effect across these producers causes an upward shift in the market supply curve for natural gas, which pushes up the price. Determining which shift dominates for a particular production well depends on the relative magnitude of the well-specific unit control costs of the regulation and the change in market price.

Given changes in market prices and costs, operators of production wells will elect to either

- continue to operate, adjusting production and input use based on new prices and costs, or
- close the production well if revenues do not exceed operating costs.

The standard closure evaluation is based on the comparison of revenues to the opportunity costs of production. If operators of production wells anticipate that these costs with the controls will exceed revenues, they will close the well.

Production well closures directly translate into quantity reductions. However, these quantity reductions will not be the only source of output change in response to the regulation. The output of production wells that continue operating with regulation will also change as will the quantity supplied from foreign sources. Affected facilities that continue to produce may increase or decrease their output levels depending on the relative magnitude of their unit control costs and the changes in market prices. Unaffected U.S. producers will not face an increase in compliance costs, so their response to higher product prices is to increase production. Foreign producers, who do not incur higher production costs because of the regulation, will respond in the same manner as the unaffected U.S. facilities.

The approach described above provides a realistic and comprehensive view of the regulation’s effect on responses at the facility-level as well as the corresponding effect on market prices and quantities for natural gas. The next section describes the specifics of the operational market model.[6]

4.2 OPERATIONAL MARKET MODEL

To estimate the economic impacts of the regulation, the competitive market paradigm outlined above was operationalized. The purpose of the model is to provide a structure for analyzing the market adjustments associated with regulations to control air pollution from the oil and natural gas production industry. The model is a multi-dimensional Lotus spreadsheet incorporating various data sources to provide an empirical characterization of the U.S. natural gas industry for a base year of 1993--the latest year for which supporting technical and economic data were available at proposal. The analysis for the final rule maintains this same base year for consistency.

To implement this model, the production wells and natural gas production facilities to be included in the analysis were identified and characterized, the supply and demand sides of the U.S. natural gas market were specified, supply and demand specifications were incorporated into a market model framework, and market adjustments due to imposing regulatory compliance costs were estimated.

4.2.1 Network of Natural Gas Production Wells and Facilities

Because of the large number of producing wells, operating units, and processing plants in the oil and natural gas production industry, it is not possible to simulate the effects of imposing the regulatory control costs at each and every facility in the industry. The following section describes the methods employed in linking the EPA engineering model plants (as described in Section 2) with the wellgroups developed by Gruy Engineering Corporation (as discussed in Section 2.3.1.1 and provided in Appendixes A and B) to construct the model units of analysis that constitute the "facilities" for use in the economic model of the U.S. natural gas industry.

To apply the Gruy Engineering Corporation data to the economic analysis, it was necessary to make appropriate adjustments to those databases. First, to ensure consistent units of measure between Gruy and supporting data sources, all units of natural gas production were converted to thousands of cubic feet per day (Mcfd). Next, because the Gruy report reflects 1989 data, it was necessary to adjust the number of gas wells to reflect 1993 data, the base year of this analysis. The 1993 gas wells, as shown in Table 2-16, were allocated across the Gruy well cohorts in each state in the same proportion as their distribution in the Gruy database. Gas well production rates (Mcfd/well) were calculated based on the Gruy data. These rates were not altered for the analysis because no evidence suggested that production rates have changed since 1989. Natural gas production was recalculated by multiplying the production rates per well by the 1993 number of producing wells in each cohort. These adjustments are reflected in Appendix B.

To facilitate the analysis, the producing field was determined to be the relevant unit of production. Thus, the individual Gruy gas wells were integrated into producing fields of homogeneous well types rather than employing units of production at the individual well level. The number of wells in each wellgroup, or cohort, was distributed as evenly as possible to each of the fields. Rather than allocate parts of a well, the number of wells was distributed as integer values so that some like fields have an additional well. The oil wells, however, were included in the analysis at the wellgroup level as a single cohort, thereby representing one or more fields.

4.2.1.1 <u>Allocation of Production Fields to Natural Gas Processing Plants.</u> Once the production fields for each state were established, each field needed to be assigned to one of the 720 U.S. natural gas processing plants listed in the OGJ.[7] Oil and gas production fields were randomly allocated to the natural gas processing plants within a State given the plant-level natural gas processing throughput for 1993 as provided in the OGJ survey. However, in many cases, natural gas that is extracted in one State is processed in another State. Table 4-1 shows which states produce more gas than they process (excess suppliers), process more than they produce (excess demanders), or process exactly what they produce. Because of this interstate flow of natural gas, it was necessary to allocate the production fields of States with excess supply to the processing plants within that State first and then assign the unallocated fields to States with excess demand. The step-by-step allocation process was as follows:

1) Assign uniform random numbers between 0 and 1 to each production field using the @RAND function in Lotus 1-2-3.

2) Sort the production fields by their random number.

3) Allocate production fields to a processing plant until the 1993 processing level at that plant is matched (exactly or as close as possible).

4) Continue to the next processing plant within that state repeating Step 3 until the 1993 processing levels at all processing plants within the State are satisfied.

Those states with excess supply were assumed to only process gas extracted from fields within that State. Production fields that were not allocated to a processing plant within their State are then assigned to the next closest State with excess demand based on the location of existing pipelines. The steps outlined above were repeated for the excess demand states until all production fields had been allocated to processing plants.

After allocating the production fields to the processing plants, like field types that were assigned to the same processing plant were combined by summing the number of wells across these fields. This further aggregation is justified since baseline and with-regulation costs per unit are the same within wellgroups, natural gas processing plants, and their combination. After this adjustment was completed, just over

TABLE 4-1. LIST OF STATES BY EXCHANGE STATUS OF NATURAL GAS, 1993

Export	Import	No exchange
Alabama	Arkansas	Alaska
Arizona	Colorado	
California	Florida	
Illinois	Kansas	
Indiana	Louisiana	
Kentucky	Wyoming	
Michigan		
Mississippi		
Montana		
Nebraska		
New Mexico		
New York		
North Dakota		
Oklahoma		
Ohio		
Oregon		
Pennsylvania		
South Dakota		
Tennessee		
Texas--North		
Texas--Gulf Coast		
Texas--West		
Utah		
Virginia		
West Virginia		

Note: Exporting States produced more natural gas in 1993 than that processed within the State, importing States processed more natural gas in 1993 than that produced within the State, while States with no exchange processed and produced an equal amount of natural gas in 1993.

8,000 production field groupings supplied the 691 processing plants.[*]

4.2.1.2 Assignment of Model Units. Once production fields had been assigned to natural gas processing plants, it became necessary to assign natural gas processing equipment to the production fields and natural gas processing plants. Processing equipment includes TEG dehydration units and condensate tank batteries (CTB). TEG units may be stand-alone units or they may exist at condensate tank batteries or natural gas processing plants. The following sections discuss the model units defined in the engineering analysis and the methods employed in allocating these units to the production fields and natural gas processing plants for the economic analysis.

Stand-alone TEG units. For this analysis, a stand-alone TEG unit was assigned to gas production fields that are deeper than 4,000 feet. This assignment was based on the assumption that wells that are less than 4,000 feet deep produce "dry gas" and do not need a stand-alone TEG unit. Data supporting this assumption are found in the U.S. Department of Energy report entitled, "Costs and Indices for Domestic Oil and Gas Field Equipment and Production Operations: 1990-1993." This report provides cost information for natural gas lease equipment by type of well, and dehydrators and their corresponding cost estimates are only listed for well types greater than 4,000 feet deep.[8]

For gas production fields with well depth greater than 4,000 feet, stand-alone TEG units were assigned based on the throughput of each field (i.e., a production field producing 25 MMcfd is assigned a model TEG unit C). To approximate the

---

[*]Total does not sum to the 720 as reported in the industry profile (section 2)because plants in OGJ processing survey that indicated no throughput for 1993 were excluded from the analysis.

engineering estimates of the number of model units, it was necessary to convert some model C and D units initially assigned to production fields into multiple model A and B units. Thus, randomly selected model C and D units were converted to model A and B units according to the ratio of average throughput per unit (as expressed in MMcfd) (i.e., one model C unit is equivalent to 125 model A units, one model D is equivalent to 350 model A units, and one model D unit is equivalent to 10 model B units).[9]

Condensate tank batteries and associated TEG units. Model condensate tank batteries were assigned to production fields based on the throughput of each field (i.e., if a field produces 2 MMcfd of natural gas, it was assigned a model CTB E). One TEG unit was assigned to each condensate tank battery based on throughput capacity so that a TEG unit A was assigned to each CTB E, a TEG unit B was assigned to each CTB F, a TEG unit C was assigned to each CTB G, and a TEG unit D was assigned to each CTB H. To approximate the engineering estimates of the number of model units, it was necessary to convert some model CTB F, G, and H units initially assigned to production fields into multiple model E units. Thus, randomly selected model F, G, and H units were converted to model E units according to the ratio of average throughput per unit (as expressed in MMcfd) (i.e., one model F unit is equivalent to 10 model E units, one model G is equivalent to 35 model E units, and one model H unit is equivalent to 100 model E units).[10]

TEG units at natural gas processing plants. TEG dehydration units are also employed at NGPPs. For this analysis, the allocation of model TEG units to model NGPPs was based on the engineering analysis so that a model NGPP A is assigned two model TEG B units, a model NGPP B was assigned three model TEG C units, and a model NGPP C was assigned three model TEG D units.

After completing the assignment of model units, every "facility" began with a model production well and ended with a model natural gas processing plant (e.g., model production well 1 → TEG dehydration unit A at CTB E → Natural gas processing plant A). As a result, the level of domestic production is equal to the level of natural gas processed at natural gas processing plants during 1993 as provided by the OGJ processing survey. Table 4-2 provides a summary of the network of production wells and production facilities by State for 1993. Because of the uncertainty related to the actual combinations of production well and processing plants, the production well-processing facility combinations developed for this analysis to reflect the base year data of 1993 will not be unique--there are likely other possible combinations of production wells and processing facilities that are consistent with the base year data.

4.2.2 Supply of Natural Gas

Producers of natural gas have the ability to vary output in the face of production cost changes. Production well-specific upward sloping supply curves for natural gas are developed to allow domestic producers to vary output in the face of regulatory control costs. The following sections provide a description of the production technology characterizing production at U.S. natural gas fields and the corresponding supply functions, as well as the foreign component of U.S. natural gas supply (i.e., imports).

4.2.2.1 Domestic Supply. For this analysis, the generalized Leontief technology was assumed to characterize natural gas production at all producing fields. This formulation allows for projection of supply curves for natural gas at the field level. In general, the supply function of a

TABLE 4-2. SUMMARY OF ALLOCATION OF PRODUCTION WELLS, PROCESSING PLANTS, AND MODEL UNITS FOR 1993 BY STATE

	Wells providing natural gas to plants within that State				Stand-alone TEG				
State	Oil wells	Gas wells	Total	Natural gas processed (Mmcfd)	A	B	C	D	Total
Alaska	1,541	157	1,698	6,499.2	286	1	1	1	289
Alabama	0	2,274	2,274	701.9	339	2	1	1	343
Arkansas	12,726	2,974	15,700	520.3	206	3	1	2	212
California	40,482	1,018	41,500	659.4	577	2	0	0	579
Colorado	8,306	7,157	15,463	1,129.6	781	4	0	4	789
Florida	2,779	1,395	4,174	621.3	369	2	1	0	372
Kansas	33,967	26,850	60,817	3,776.5	2,747	13	3	4	2,767
Kentucky	0	7,842	7,842	118.0	0	0	0	0	0
Louisiana	71,049	131,256	202,305	11,865.5	5,973	62	4	5	6,044
Michigan	2,099	2,196	4,295	859.0	69	1	0	0	70
Mississippi	1,811	278	2,089	209.6	92	1	0	1	94
Montana	0	83	83	7.1	1	0	0	0	1
North Dakota	2,101	80	2,181	83.2	9	0	0	0	9
New Mexico	5,606	17,596	23,202	2,122.2	1,205	10	1	0	1,216
Oklahoma	59,564	12,472	72,036	2,863.4	1,834	21	2	0	1,857
Pennsylvania	0	258	258	8.2	0	0	0	0	0
Ohio	0	609	609	8.8	0	0	0	0	0
West Virginia	0	24,154	24,154	337.8	0	0	0	0	0
Texas-Gulf Coast	56,558	17,647	74,205	7,037.9	5,119	47	4	2	5,172
Texas-North	50,502	14,521	65,023	1,679.7	882	7	1	0	890
Texas-West	61,913	7,750	69,663	3,284.0	1,778	6	3	0	1,787

TABLE 4-2. SUMMARY OF ALLOCATION OF PRODUCTION WELLS, PROCESSING PLANTS, AND MODEL UNITS FOR 1993 BY STATE (CONTINUED)

	Condensate tank batteries					Natural gas processing plants			
State	E	F	G	H	Total	A	B	C	Total[a]
Alaska	27	2	3	4	36	0	0	3	3
Alabama	79	4	1	2	86	2	4	3	9
Arkansas	60	3	3	2	68	1	1	1	3
California	281	6	3	0	290	15	11	2	28
Colorado	326	6	0	4	336	27	14	4	45
Florida	84	4	2	2	92	0	1	1	2
Kansas	555	32	15	6	608	6	4	11	21
Kentucky	0	0	0	0	0	0	3	0	3
Louisiana	2,765	162	32	25	2,984	14	22	32	68
Michigan	86	4	1	0	91	7	9	11	27
Mississippi	54	3	0	1	58	3	2	1	6
Montana	1	0	0	0	1	6	0	0	6
North Dakota	27	1	1	0	29	5	1	0	6
New Mexico	571	40	7	0	618	6	20	7	33
Oklahoma	1,175	53	1	4	1,233	34	48	10	92
Pennsylvania	0	0	0	0	0	1	0	0	1
Ohio	0	0	0	0	0	0	1	0	1
West Virginia	0	0	0	0	0	3	2	2	7
Texas-Gulf Coast	2,220	99	11	15	2,345	22	69	21	112
Texas-North	665	32	4	0	701	42	27	7	76
Texas-West	1,418	15	10	1	1,444	34	44	10	88
Utah	137	8	1	2	148	7	5	2	14
Wyoming	918	26	5	2	951	15	16	9	40

natural gas producing field resulting from the generalized Leontief technology is:

$$q_j = \gamma_j + \frac{\beta}{2}\left[\frac{1}{r}\right]^{1/2} \tag{4.1}$$

where

q_j = annual production of natural gas (Mcf) for field $j = 1$ to n,

r = national wellhead price of natural gas,

β = negative supply parameter (i.e., $\beta < 0$), and

γ_j = productive capacity of field j.

Figure 4-4 illustrates the theoretical supply function of Equation (4.1). As shown, the upward-sloping supply curve is specified over a productive range with a lower bound of zero that corresponds with a shutdown price equal to $\frac{\beta^2}{4\gamma_j^2}$ and an upper bound given by the productive capacity of q_j^M that is approximated by the supply parameter γ_j. The curvature of the supply function is determined by the β parameter (see Appendix C for a discussion of the derivation and interpretation of this parameter).

To specify the supply function of Eq. (4-1) for this analysis, the β parameter is computed by substituting the market supply elasticity for natural gas (ξ), the wellhead price of natural gas (r), and the production-weighted average annual production level of natural gas per well (q) into the following equation:

$$\beta = -\xi 4q\left[\frac{1}{r}\right]^{-1/2}. \tag{4.2}$$

The market-level supply elasticity for natural gas is assumed to be 0.2624, which reflects the production-weighted average

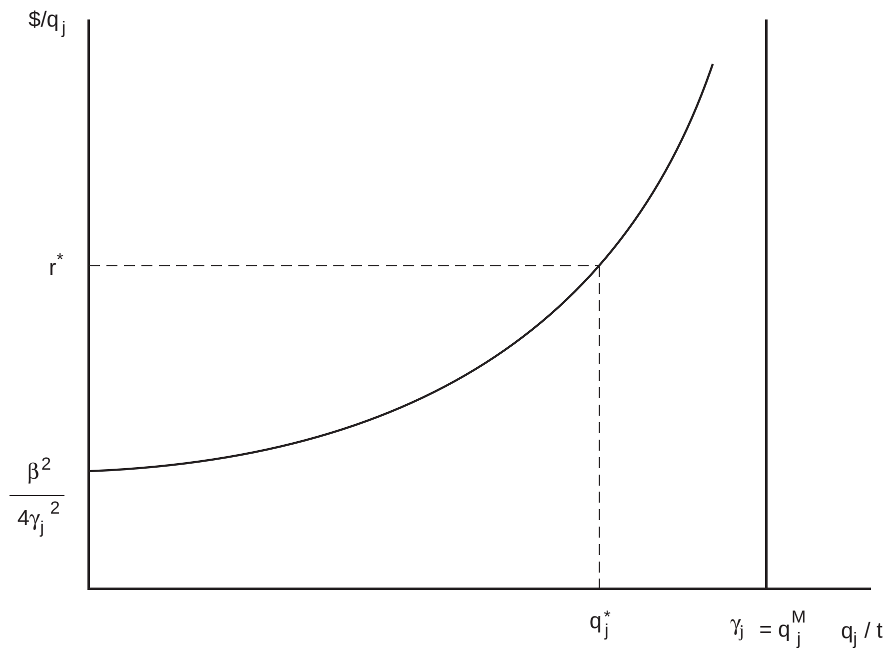


Figure 4-4. Theoretical supply function of natural gas producing well.

supply elasticity estimated across EPA regions as shown in Table 4-3.[11] The 1993 wellhead price of natural gas is $2.01 per Mcf and the production-weighted average annual level of natural gas production per well based on the Gruy database is 131,496 Mcf. The β parameter is calculated by incorporating these values into Equation (4.2) resulting in an estimate of the β parameter equal to -195,674.

Unlike the product-specific β, the individual supplier-level elasticity of supply is not constant, but varies across each producing field with the level of production, q_j. For high production fields, the elasticity of supply will be low reflecting the low responsiveness to price changes of large wells due to high overhead expenses and low extraction costs as described in the literature. For low production fields, the elasticity of supply will be high reflecting the high responsiveness to price changes of "stripper" wells. Since stripper wells produce a small product volume and have low

TABLE 4-3. SHORT-RUN SUPPLY ELASTICITY ESTIMATES FOR NATURAL GAS BY EPA REGION

EPA Region	Estimates of short-run elasticities
1	0.852
2	0.263
3	0.207
4	0.122
5	0.118
6	0.463
Weighted average	0.2624

Source: U.S. Department of Energy. Documentation of the Oil and Gas Supply Module. DOE/EIA-M063. Energy Information Administration, Oil and Gas Analysis Branch. Washington, DC. March 1994.

overhead expenses, producers usually respond to fluctuations in price of oil or gas by ceasing production when revenues fall below operating costs, and possibly resuming production when it is profitable.[12] As a result, domestic capacity utilization fluctuates mainly as stripper wells are changed from idle to production status.

The intercept of the supply function, γ_j, approximates productive capacity and varies across producing fields. This parameter does not influence the field's production responsiveness to price changes as does the β parameter. Thus, the parameter γ_j is used to calibrate the model so that each field's supply equation is exact using the Gruy data.

4.2.2.2 Foreign. The importance of including foreign imports in the economic model is highlighted by the significant level of U.S. importation of natural gas that currently reflects over 10 percent of U.S. domestic consumption. Thus, the model specifies a general formula for the foreign supply for natural gas that is:

$$q^I = A^I [r]^{\xi^I} \tag{4.3}$$

where

q_I = foreign supply of natural gas (Mcf),

A^I = positive constant, and

ξ^I = foreign supply elasticity for natural gas.

Difficulty in estimating foreign trade elasticities has long been recognized and precludes inclusion of econometric estimates (new or existing). International trade theory suggests that foreign trade elasticities are larger than domestic elasticities. In fact, at the limit, the foreign trade elasticities are infinite, reflecting the textbook case of price-taking in world markets by small open economy producers and consumers. For this analysis, a value of 0.852 is assumed for the import supply elasticity, which is the highest domestic supply elasticity estimate from Table 4-3. The multiplicative foreign supply parameter, A^I, is determined by backsolving given estimates of the import supply elasticities, 1993 wellhead price, and the quantities of U.S. imports 1993.

4.2.2.3 Market Supply. The market supply of natural gas (Q^S) is the sum of supply from all natural gas producers, i.e.,

$$Q^S = q^I + \sum_j q_j^s \tag{4.4}$$

where q^I is foreign supply of natural gas and $\sum_j q_j^s$ is the domestic supply of natural gas, which is the sum of natural gas production across all U.S. producing fields (j).

4.2.3 Demand for Natural Gas

Natural gas end users include residential and commercial customers, as well as industrial firms and electric utilities. These customer groups have very different energy requirements and thus quite different service needs. Therefore, the model specifies a general formula for the demand of natural gas by end-use sector (q_i^d), that is,

$$q_i^d = B_i^d \, [p_i]^{\eta_i^d} \tag{4.5}$$

where

p_i = the end-user price for sector I,

η_i^d = the demand elasticity for end-use sector I,

B_i^d = a positive constant

The multiplicative demand parameter, B_i^d, calibrates the demand equation so that each end-use sector replicates its observed 1993 level of consumption given data on price and the demand elasticity.

Table 4-4 provides the estimates of the demand elasticity by end-use sector that are employed in the model.[13] In a survey of price elasticities of demand for natural gas, Al-Sahlawi found that short-run elasticities of demand range from -0.035 to -0.686 in the residential sector and -0.161 to -0.366 in the commercial sector.[14] As shown in Table 4-4, this analysis employs the mid-point of the range for each of these end-use sectors. Industrial demand for natural gas is a derived demand resulting from producers optimizing the relative use of fuels that comprise the energy input to the production function. Based on time-series data across 9 U.S. states, Beierlin, Dunn, and McConnor used a combination of error components and seemingly unrelated regression to

TABLE 4-4. SHORT-RUN DEMAND ELASTICITY ESTIMATES FOR NATURAL GAS BY END-USER SECTOR

End-use sector	Estimate of the short-run demand elasticity
Residential	-0.3605
Commercial	-0.2635
Industrial	-0.6100
Electric utility[a]	-1.0000

[a] Value is assumed due to lack of literature estimates of this parameter for electric utilities. Higher absolute value than other sectors because of greater fuel-switching capabilities.

Source: Al-Sahlawi, Mohammed A. "The Demand for Natural Gas: A Survey of Price and Income Elasticities," Energy Journal Vol. 10, No. 1, January 1989.

estimate a short-run elasticity of -0.61 for natural gas.[15] To the best of our knowledge there exist no studies that estimate short-run demand elasticities for electric utilities. Because electric utilities have greater fuel switching capabilities than other end-users, we assume a more responsive short-run elasticity of -1 for this group in the model.

The total market demand for natural gas (Q^D) is the sum across all consuming end-use sectors, i.e.,

$$Q^D = \sum_i q_i^d \quad . \tag{4.6}$$

An additional component of natural gas consumption is that used as lease, plant, and pipeline fuel. This consumption is fairly constant over time varying only with fluctuations of natural gas production. For the purposes of this analysis, this component is treated as an additional end-use sector consuming at a constant amount without and with the regulation.

4.2.4 Incorporating Regulatory Control Costs

The starting point for assessing the market impact of the regulations is to incorporate the regulatory control costs into the natural gas production decision. The regulatory control costs for each model unit are presented in Table 3-9 of Section 3. An additional aspect of the regulation is the product recovery credit received by natural gas producers as a result of adding the controls. These credits do not directly affect the production decisions as do the costs of adding the pollution controls. Rather these credits are added revenues that each producer gains after complying with the regulation.

The focus of incorporating regulatory control costs into the model structure is to appropriately assign the costs to the natural gas flows directly affected by the imposition of HAP emission controls. This assignment includes the identification of affected entities and determination of their control costs and the inclusion of these costs in the production decision of each affected entity.

4.2.4.1 Affected Entities. For this analysis, affected units were randomly selected given the percentages provided in Tables 3-7 through 3-9 of Section 3 and then assigned the appropriate compliance costs. Specifically, the following steps were undertaken:

- Each production field was assigned a uniform random value between 0 and 1 using the @RAND function in Lotus 1-2-3.
- Affected units were determined to be those with a random value below the percentage affected as given in Tables 3-7 through 3-9 for each model type.
- Total annual compliance costs, as shown in Table 3-9, were assigned to affected units and aggregated across model units for each "facility," or production field-processing plant combination.

The total annual compliance costs are expressed at the model unit level and must be converted to a per Mcf basis for inclusion in the model, i.e., application to affected product flows. To avoid double counting, compliance costs assigned to natural gas processing plants are further allocated to the multiple production fields providing natural gas according to their share of total natural gas processed at the plant. The total annual compliance costs per Mcf (c_j) for each affected production field j are computed as the sum of total annual compliance costs for affected TEG unit(s), condensate tank battery, and natural gas processing plant divided by the annual production level of the field.

4.2.4.2 Natural Gas Supply Decisions. The production decisions at the individual producing fields are affected by the total annual compliance costs, c_j, which reflect the shift in marginal cost and are expressed per Mcf of natural gas. If the producing field serves an affected stand-alone TEG unit, condensate tank battery, or natural gas processing plant, then its supply equation will be directly affected by the regulatory control costs, which enter as a net price change, i.e., r_j - c_j. Thus, the supply function for producing fields, assuming the generalized Leontief production technology becomes:

$$q_j = \gamma_j + \frac{\beta}{2}\left[\frac{1}{r_j - c_j}\right]^{1/2} \tag{4.7}$$

The discussion above assumes that producing natural gas is profitable. However, in confronting the decision to comply with the regulation, a producer's optimal choice could be to produce zero output (i.e., close the production field). As shown in Figure 4-4, if the net wellhead price (r_j -c_j) falls below the shutdown price of $\frac{\beta^2}{4\gamma_j^2}$, then the producing field's production response for the supply equation given the regulatory control costs will be less than or equal to zero (i.e., $q_j \leq 0$).

4.2.5 Model Baseline Values and Data Sources

Table 4-5 provides the 1993 baseline equilibrium values for wellhead and end-user prices, domestic and foreign production, and consumption by end-use sector.[16] The level of domestic production is equivalent to the level of natural gas processed at natural gas processing plants during 1993 as obtained from the OGJ processing survey.[17] The consumption level for lease, plant, and pipeline fuel was adjusted to ensure that national production and consumption levels were exact for the model's 1993 characterization of the U.S. natural gas market.

4.2.6 Computing Market Equilibria

This section provides a summary of the model structure and a description of the equilibria computations of the model. A complete list of exogenous and endogenous variables, as well as the model equations, is given in Appendix D.

Producers' responses and market adjustments can be conceptualized as an interactive feedback process. Producers

TABLE 4-5. BASELINE EQUILIBRIUM VALUES FOR ECONOMIC MODEL: 1993

Item	Price[a] ($/Mcf)	Quantity (MMcf)
Producers		
Domestic	$2.01	17,440,586
Foreign	$2.01	2,350,115
Total	$2.01	19,790,701
Consumers		
Residential	$6.15	4,956,000
Commercial	$5.16	2,906,000
Industrial	$3.07	7,936,000
Electric utility	$2.61	2,682,000
Other	N/A	1,310,701
Average/total	$4.16	19,790,701

[a] For producers, price reflects the national wellhead price. For consumers, price reflects the appropriate national end-user price.

[b] For producers, quantity reflects the total production level. For consumers, quantity reflects the appropriate level of consumption.

Source: Department of Energy. Natural Gas Monthly. Energy Information Administration, Washington, DC. October 1994.

face increased production costs due to compliance, which causes individual production responses; the cumulative effect, which leads to a change in the wellhead price that all producers (affected and unaffected) face; and the end-user price that all consumers face, which leads to further responses by producers (affected and unaffected) as well as consumers and thus new market prices, and so on.* The new equilibria after imposition of these regulatory control costs is the result of a series of iterations between producer and consumer responses and market adjustments until a stable

*End-user prices are determined by adding the new wellhead price to the absolute markup for each end-user.

market price arises where total market supply equals total market demand, i.e.,

$$Q^S = Q^D \quad .$$

This process is simulated given the producer and consumer response functions and market adjustment mechanisms to arrive at the post-compliance equilibria.

The process for determining equilibrium prices (and outputs) with the increased production cost is modeled as a Walrasian auctioneer. The auctioneer calls out a wellhead price for natural gas (indirectly yielding end-user prices) and evaluates the reactions by all participants (producers and consumers, both foreign and domestic) comparing quantities supplied and demanded to determine the next price that will guide the market closer to equilibrium, i.e., market supply equal to market demand. An algorithm is developed to simulate the auctioneer process and find a new equilibrium price and quantity for natural gas. Decision rules are established to ensure that the process will converge to an equilibrium, in addition to specifying the conditions for equilibrium. The result of this approach is a combination of wellhead price and end-user prices with the regulation that equilibrates supply and demand for the U.S. natural gas market.

The algorithm for deriving the with-regulation equilibrium can be generalized to five recursive steps:

1) Impose the control cost on the production wells, thereby affecting their supply decisions.

2) Recalculate the market supply of natural gas.

3) Determine the new wellhead price via the price revision rule and add appropriate markups to arrive at end-user prices.

4) Recalculate the supply function of producing fields and foreign suppliers with the new wellhead price, resulting in a new market supply of natural gas. Evaluate end-use consumption levels at the new end-

user prices, resulting in a new market demand for natural gas.

5) Return to Step 3, and repeat steps until equilibrium conditions are satisfied (i.e., the ratio of market supply to market demand is equal to 1).

4.3 REGULATORY IMPACT ESTIMATES

The model results can be summarized as market- and industry- and societal-level impacts due to the regulation.

4.3.1 Market-Level Results

Market-level impacts include the market adjustments in price (wellhead and end-user) and quantity for natural gas, including the changes in international trade flows. Table 4-6 provides the market adjustments for each regulatory scenario. As shown, the changes in wellhead and end-use prices for each regulatory scenario are all nearly zero (less than 0.0005 percent change). The market adjustments associated with the regulation are also negligible in comparison to the observed trends in the U.S. natural gas market. For example, between 1992 and 1993, the average annual wellhead price increased by 14 percent, while domestic production of natural gas rose by 3 percent.[18] The increase in foreign imports of natural gas is also inconsequential (totaling less than 0.0004 percent) for each regulatory scenario.

4.3.2 Industry-Level Results

Industry-level impacts include an evaluation of the changes in revenue, costs, and profits; the post-regulatory compliance cost; production well and natural gas processing plant closures; and the change in employment attributable to

TABLE 4-6. SUMMARY OF NATURAL GAS MARKET ADJUSTMENTS FOR MAJOR SOURCES

Item	Major sources			
	Price ($/Mcf)	Percent change (%)	Quantity (MMcf)	Percent change (%)
Producers				
Domestic	$2.01	0.00044%	17,440,551	-0.00020%
Foreign	$2.01	0.00044%	2,350,123	0.00035%
Total			19,790,674	-0.00014%
Consumers				
Residential	$6.15	0.00014%	4,955,997	-0.00005%
Commercial	$5.16	0.00017%	2,905,999	-0.00005%
Industrial	$3.07	0.00029%	7,935,986	-0.00018%
Electric utility	$2.61	0.00034%	2,681,991	-0.00034%
Other	N/A	N/A	1,310,701	0.00000%
Total	$4.16	0.00021%	19,790,674	-0.00014%

(continued)

the change in industry output. Workers' dislocation costs associated with industry-wide job losses are also computed. Table 4-7 summarizes these industry-level impacts by regulatory scenario.

TABLE 4-7. INDUSTRY-LEVEL IMPACTS

Oil and Natural Gas Production Category	
Change in revenues ($\$10^6$)	\$3.1
Market adjustments	\$0.2
Product recovery	\$2.9
Change in costs ($\$10^6$)	\$7.4
Post-regulatory control costs	\$7.5
Costs of production adjustment	-\$0.1
Change in profits ($\$10^6$)	-\$4.3
Closures	
Production wells	0
Natural gas processing plants	0
Employment loss	0
Natural Gas Transmission and Storage Category	
Compliance Costs ($\$10^6$)	\$0.3

4.3.2.1 Post-Regulatory Compliance Cost. The post-regulatory compliance cost at each facility can be calculated as the product of the total annual compliance cost per unit (c_j) and the new output rate ($q^{*\prime}$). At the industry-level, the post-regulatory compliance cost for major sources is roughly \$7.5 million for production facilities and reflects the sum of the total annual compliance cost across all facilities continuing to operate in the post-compliance equilibrium. Thus, the post-compliance cost is not necessarily equal to the estimated compliance costs before accounting for market adjustments. They differ because producing wells output rates may change at affected producing wells.

4.3.2.2 Revenue, Production Cost, and Profit Impacts. The economic model generates information on the change in individual and market quantities and market price in the oil and natural gas production industry. This allows computation of the change in total revenue and total cost at the industry level. For major sources, the total increase in revenue is $3 million and includes the change in product revenue associated with market adjustments ($0.2 million), which is the difference between baseline product revenue and post-compliance product revenue, and the added revenue associated with the product recovery credits ($2.9 million). The total increase in production cost is $7.4 million and reflects the post-compliance costs of production minus the baseline costs of production, which will account for the increase in costs due to the regulation ($7.5 million) and the decrease in costs due to the lower output rate ($0.1 million). These costs amount to just 0.004 percent of the total revenues in 1993 of the 300 largest publicly traded oil and natural gas producing companies in the U.S.[19,20] The changes in total revenue and total cost are used to measure the profitability impact of the regulations which indicates a loss of $4.3 million at the industry level due to regulation.

The economic model also uses changes in industry revenues and costs to project closures of producing wells and natural gas processing plants and to assess employment impacts in the industry. No closure or employment effects are estimated to occur.

4.3.2.3 Screening Analysis for Natural Gas Transmission and Storage

The cost estimates for the 7 major sources in the natural gas transmission and storage category were not included in the market model reported above. Between proposal and promulgation of this rule, data was collected through surveys and site visits for 81 facilities, however, only one facility in EPA’s database, KN Interstate Gas Transmission Company, is known to be affected by the standard. We do not have information on the other six facilities estimated to be affected by the rule. Below is a screening analysis of impacts on the natural gas transmission and storage industry, the calculated impact for KN Interstate Gas Transmission Company, and an approach to characterize potential impacts for other affected facilities.

First, to screen the potential impacts on the market for natural gas transmission and storage, we calculate the ratio of total compliance costs with industry revenues. This calculation can give some insight into potential price increases and the level of potential impacts on the transmission and storage market. Information on pipeline economics from the OGJ[21] indicates total 1997 revenues of $16.1 billion for all pipeline firms listed. A total regulatory cost of $300,000 would represent 0.02% of market revenues. This level of impact is unlikely to be enough of a shock to production costs throughout the market to cause the supply curve to shift upward, so market price would not be expected to increase as a result of the regulation. This impact is also overstated to the extent that the table of firms from the OGJ does not list all of the firms in the industry. The table includes all "major" and "non-major" firms (as defined by the FERC), which are required to report pipeline company statistics. The overstatement of impacts will be minimal if the firms reported in the OGJ table constitute a large majority of the industry.

To screen for impacts of the rule on individual firms, we calculate the ratio of firm compliance cost to firm revenues[*]. If the ratio is greater that one percent for a substantial number of firms this screening would indicate a need for

[*] It should be noted that while the estimated regulatory impact of $300,000 is based on seven facilities, this analysis is based on firm-level impacts. A firm may own one facility or several facilities - a portion of which might be affected by the final rule.

further evaluation, especially for small businesses in accordance with requirements of the Regulatory Flexibility Act and the Small Business Regulatory Enforcement and Fairness Act. Using the information provided by the OGJ, we selected data for 42 pipeline companies that transferred greater than 100 Mmscf of natural gas per year corresponding to the throughput of EPA’s model TEG-D units and larger. It is assumed that companies listed in this table with less than 100 Mmscf would not be affected by the rule because they may not be a major source (as defined by the Clean Air Act), or they may be major but excluded from this regulation due to the 85 Mmscf cut-off for control requirements. From the information given in the table, we obtained the total volume of gas sold and transferred, and operating revenues to calculate the cost-to-revenues ratios for each company. The firms were then divided into two categories: (1) those with throughput of 100 but less than 500 Mmscf (i.e., model TEG-D size category), and (2) those with throughput greater than or equal to 500 Mmscf (i.e. model TEG-E facilities). Table 4-8 below displays the firm information for the two TEG size categories. We then calculate the cost-to-revenue ratios assuming one TEG transfers all of the throughput indicated for the firm (i.e. a TEG-D can transfer as little as 100 Mmscf , or as much as 499 Mmscf). The cost associated with controlling a single TEG is $49,787, which is used in the numerator of the ratio.

As Table 4-8 demonstrates, this rule will have a minimal impact on affected firms. All but one of the 42 companies in the analysis had a cost-to-revenue ratio well below 1%, including KN Interstate Gas with a ratio of 0.06%. The range of ratios for the listed firms is from 0.003% to 1.32%. The average firm ratio is 0.09%, which indicates that the impacts are typically well below 1/10th of one percent.

It is also possible for a firm to transfer it’s volume through multiple TEGs of various sizes. As is previously mentioned, TEGs with throughputs below 85 Mmscf do not have control requirements resulting from this rule. Therefore, firms that utilize multiple TEG units will have a portion of those controlled by the rule. Again, we do not have information on the number of affected TEG units operated at the listed firms. Alternatively, we calculate the number of TEGs it would take to equate to 1% of a firm’s revenues. Table 4-8 shows that on average, it would require 57 TEGs to be controlled for compliance costs to reach 1% of firm revenues.

In summary, the screening of compliance costs on market and firm revenues shows minimal impacts on the natural gas transmission and storage industry. Nearly all of the firms have impacts below 1%, and it would require the control of 57 TEGs on average for greater impacts to be realized. With this information, it is not likely that small businesses will be significantly impacted and the further evaluation of the industry is not warranted.

TABLE 4-8. IMPACTS FOR SELECTED* NATURAL GAS TRANSMISSION AND STORAGE FIRMS						
Company Name by TEG Size	Volumes (MMcf)			Operating Revenues (1993 dollars)**	Cost/Revenue Ratio	No. TEGs Needed for 1% Impact
	Transferred	Sold	Total			
TEG-D Firms:						
U-T Offshore	122,892	0	122,892	3,526,863	1.412	1
Sabine Pipeline Co	273,669	0	273,669	14,941,413	0.333	3
Midwestern Gas Tran	157,738	0	157,738	16,521,746	0.301	3
Viking Gas	166,588	0	166,588	18,458,026	0.270	4
Stingray Pipeline	267,782	0	267,782	19,449,461	0.256	4
Sea Robin Pipeline	283,661	0	283,661	23,226,979	0.214	5
Michigan Gas Storage	444,942	0	444,942	23,233,501	0.214	5
Trailblazer Pipeline	200,382	0	200,382	32,741,588	0.152	7
High Island Offshore	302,330	0	302,330	42,188,177	0.118	8
Mojave Pipeline	109,543	0	109,543	44,554,017	0.112	9
E. Tennessee N. Gas	117,688	0	117,688	48,705,186	0.102	10
Miss. River Trans	352,591	0	352,591	60,086,191	0.083	12
KN Interstate Gas	159,195	0	159,195	74,267,255	0.067	15
Questar Pipeline	264,321	0	264,321	100,031,525	0.050	20
Algonquin Gas	341,090	900	341,990	141,675,531	0.035	28
Iroquois Gas Trans	333,479	0	333,479	143,172,934	0.035	29
Williams Gas	336,685	0	336,685	168,867,319	0.029	34
Kern River Gas Trans	285,656	0	285,656	176,080,382	0.028	35
Wyoming Interstate	210,885	0	210,885	256,558,085	0.019	52
Florida Gas Co	490,000	0	490,000	288,381,850	0.017	58
TEG-E Firms:						
Columbia Gulf Trans	888,395	0	888,395	126,245,855	0.039	25
Transwestern	520,369	1,245	521,614	146,570,276	0.034	29
Trunkline Gas	619,255	0	619,255	156,438,038	0.032	31

TABLE 4-8. IMPACTS FOR SELECTED*
NATURAL GAS TRANSMISSION AND STORAGE FIRMS

Company Name by TEG Size	Volumes (MMcf) Transferred	Sold	Total	Operating Revenues (1993 dollars)**	Cost/Revenue Ratio	No. TEGs Needed for 1% Impact
Nat'l Fuel Gas Supply	903,613	0	903,613	162,186,313	0.031	33
Koch Gateway Pipln	731,008	0	731,008	164,690,991	0.030	33
Northern Border Pipln	845,297	0	845,297	166,470,729	0.030	33
NorAm Gas Trans	586,777	266	587,043	209,625,182	0.024	42
PG&E Gas Trans	989,257	0	989,257	217,208,171	0.023	44
Gr. Lakes Gas Trans	921,438	0	921,438	251,856,222	0.020	51
Northwest Pipeline	721,547	0	721,547	256,553,426	0.019	52
Colorado Interstate	515,674	37,616	553,290	256,558,085	0.019	52
Texas Gas	773,611	9,556	783,167	296,581,690	0.017	60
Panhandle Eastern	659,201	0	659,201	324,162,038	0.015	65
El Paso N. Gas	1,275,208	3,609	1,278,817	458,897,523	0.011	92
Northern N. Gas Co	1,593,445	1,300	1,594,745	473,018,020	0.011	95
CNG Transmission	754,985	14,211	769,196	489,268,612	0.010	98
ANR Pipeline Co	1,798,601	0	1,798,601	614,855,684	0.008	123
Columbia Gas Trans	1,295,810	0	1,295,810	630,544,401	0.008	127
Tennesee Gas	1,942,217	26,124	1,968,341	721,611,079	0.007	145
Texas Eastern	1,300,276	2,022	1,302,298	864,640,515	0.006	174
N. Gas Pipeline of Am	1,664,131	43,276	1,707,407	879,490,612	0.006	177
Transcontinental	2,606,297	215,166	2,821,463	1,346,416,523	0.004	270

* We selected 42 firms from the OGJ that may have size D and E TEGs. Only 7 firms are estimated to be affected by the regulation, however, all 42 firms in the OGJ are evaluated here due to the unkown specification of affected firms.

** OGJ reports 1997 revenues, which are converted in this table to 1993 dollars using the Bureau of Labor Statistics Producer Price Index.

4.4 Economic Welfare Impacts

The value of a regulatory policy is traditionally measured by the change in economic welfare that it generates. Welfare impacts resulting from the regulatory controls on the oil and natural gas production industry will extend to the many consumers and producers of natural gas. Consumers of natural gas will experience welfare impacts due to the adjustments in price and output of natural gas caused by the imposition of the regulations. Producer welfare impacts result from the changes in product revenues to all producers associated with the additional costs of production and the corresponding market adjustments. The theoretical approach used in applied welfare economics to evaluate policies is presented in Appendix E and indicates our approach to estimation of the changes in economic welfare.

The market adjustments in price and quantity in the oil and natural gas production industry were used to calculate the changes in aggregate economic welfare using applied welfare economics principles. Table 4-9 shows the estimated economic welfare change. These estimates represent the social cost of the regulation. For major sources, the social cost of the regulation is $4.9 million with producers of natural gas incurring over 95 percent of the total burden. An alternative measure of the social cost is the total annual compliance cost as estimated by the engineering analysis. However, that measure fails to account for market adjustments and the fact that units may close and not incur the regulatory costs. Thus, the difference between the engineering estimate of social cost and that derived through economic welfare analysis is the deadweight loss to society of the reallocation of resources.

TABLE 4-9. ECONOMIC WELFARE IMPACTS ($\$10^6$)

Change in consumer surplus	-\$0.32
Change in producer surplus	-\$4.33
Domestic	-\$4.36
Foreign	\$0.04
Change in surplus for transmission and storage	-\$0.30
Change in economic welfare	-\$4.94

References:

1. U.S. Environmental Protection Agency. Oil and Natural Gas Production: An Industry Profile. Office of Air Quality Planning and Standards, Research Triangle Park, NC. October 1994. p. 4.

2. Farzin, Yeganeh Hossein. Competition in the Market for an Exhaustible Resource. Jai Press, 1986.

3. Crimer, Jacques. Models of the Oil Market. Harwood Academic Publishers, 1991.

4. Ref. 23, p. 477-517.

5. Ref. 23.

6. Bradley, M.E., and Wood, A.R.O. "Forecasting Oilfield Economic Performance," JPT. November 1994. p. 965-971.

7. Ref. 39, p. 63-109.

8. U.S. Department of Energy. Costs and Indices for Domestic Oil and Gas Field Equipment and Production Operations: 1990-1993. Energy Information Administration, Washington, DC. July 1994. Appendices H through M.

9. Ref. 1, Table 4-1.

10. Ref. 1, Table 4-1.

11. U.S. Department of Energy. Documentation of the Oil and Gas Supply Module (OGSM) DOE/EIA-M063. Energy Information Administration, Oil and Gas Analysis Branch, Washington, DC. March 1994.

12. Science Application International Corporation. The Oil and Gas Exploration and Production Industry: Trends 1985-2000. Draft report prepared for the U.S. Environmental Protection Agency, Office of Solid Waste. April 1993.

13. Al-Sahlawi, Mohammed A. "The Demand for Natural Gas: A Survey of Price and Income Elasticities," Energy Journal 10(1) January 1989.

14. Ref. 69.

15. Ref. 69.

16. U.S. Department of Energy. Natural Gas Monthly. Energy Information Administration, Washington, DC. Tables 18, 19, 20, and 21. October 1994.

17. Ref. 39, p. 63.

18. Ref. 72, Table 4.

19. Ref. 46.

20. Dun's Analytical Services. Industry Norms and Key Business Ratios. Dun and Bradstreet, Inc. 1994.

21. "Weather, Construction Inflation Could Sqeeze North American Pipelines." Oil and Gas Journal Special. August 31, 1998.

SECTION 5
FIRM-LEVEL ANALYSIS

A regulatory action to reduce air emissions from the oil and natural gas production industry will potentially affect owners of the regulated entities. Firms or individuals that own the production wells and processing facilities are legal business entities that have the capacity to conduct business transactions and make business decisions that affect the facility. The legal and financial responsibility for compliance with a regulatory action ultimately rests with these owners who must bear the financial consequences of their decisions. Thus, an analysis of the firm-level impacts of the EPA regulation involves identifying and characterizing affected entities, assessing their response options by modeling or characterizing the decision-making process, projecting how different parties will respond to a regulation, and analyzing the consequences of those decisions. Analyzing firm-level impacts is important for two reasons:

- Even though a production well or processing facility is projected to be profitable with the regulation in place, financial constraints affecting the firm owning the facility may mean that the plant changes ownership.
- The Regulatory Flexibility Act (RFA) requires that the impact of regulations on all small entities, including small companies, be assessed.

Environmental regulations such as the NESHAP for the oil and natural gas production industry affect all businesses, large and small, but small businesses may have special problems in complying with such regulations. The RFA of 1980 requires that special consideration be given to small entities affected by Federal regulation. Under the 1992 revised EPA guidelines for implementing the RFA, an initial regulatory flexibility analysis (IRFA) and a final regulatory flexibility analysis (FRFA) will be performed for every rule subject to the Act that will have any economic impact, however small, on any small entities that are subject to the rule, however few, even though EPA may not be legally required to do so. In 1996, the Small Business Regulatory Enforcement Fairness Act (SBREFA) was passed, which further amended the RFA by expanding judicial review of agencies' compliance with the RFA and by expanding small business review of EPA rulemaking.

Although small business impacts are expected to be minimal due to the size cutoffs for TEG dehydration units,[1] this firm-level analysis addresses the RFA requirements by measuring the impacts on small entities in the oil and natural gas production source category. In addition, the screening analysis presented in section 4.3.2.3 provides an indication that small transmission and storage firms are also not likely to experience significant impacts.

Small entities include small businesses, small organizations, and small governmental jurisdictions and may be defined using the criteria prescribed in the RFA or other criteria identified by EPA. Small businesses are typically defined using Small Business Association (SBA) general size standard definitions for Standard Industrial Classification (SIC) codes. Firms involved in the oil and natural gas production industry include producers (majors and independents), transporters (pipeline companies), and

[1]TEG dehydration units that process less than 3 MMcfd are not expected to be affected by the regulation. It follows that the smaller owners would likely own only units of this type.

distributors (local distribution companies) that are covered by various SIC codes. The relevant industries include SICs 1311 (Crude Petroleum and Natural Gas), 1381 (Drilling Oil and Gas Wells), 1382 (Oil and Gas Exploration Services), 2911 (Petroleum Refining), 4922 (Natural Gas Transmission), 4923 (Gas Transmission and Distribution) and 4924 (Natural Gas Distribution). The SBA size standards for these industries are shown in Table 5-1.

TABLE 5-1. SBA SIZE STANDARDS BY SIC CODE FOR THE OIL AND NATURAL GAS PRODUCTION INDUSTRY

SIC code	Description	SBA size standard in number of employees/annual sales
1311	Crude Petroleum and Natural Gas	500
1381	Drilling Oil and Gas Wells	500
1382	Oil and Gas Exploration Services	$5 million
2911	Petroleum Refining	1,500
4922	Natural Gas Transmission	$5 million
4923	Natural Gas Transmission and Distribution	$5 million
4924	Natural Gas Distribution	500

The general steps involved in analyzing company-level impacts include identifying and analyzing the possible options facing owners of affected facilities and analyzing the impacts of the regulation including impacts on small companies and comparing them to impacts on other companies.

5.1 ANALYZE OWNERS' RESPONSE OPTIONS

In reality, owners' response options to the impending regulation potentially include the following:

- installing and operating pollution control equipment,

- closing or selling the facility, and
- complying with the regulation via process and/or input substitution (versus control equipment installation).

This analysis assumes that the owners of an affected facility will pursue a course of action that maximizes the value of the company, subject to uncertainties about actual costs of compliance and the behavior of other companies.

The market model presented in Section 4 models the facility- and market-level impacts for natural gas producing wells and processing facilities under the owners' first two options listed above. Evaluating facility and market impacts under the third option listed above requires detailed data on production costs and input prices; costs and revenues associated with alternative services/products; and other owner motivations, such as legal and financial liability concerns, and is beyond the scope of this analysis. Consequently, this analysis is based on the assumption that owners of oil and natural gas production facilities respond to the regulation by installing and operating pollution control equipment or discontinuing operations at production wells or process facilities that they own. The facility- and market-level impacts, presented in Section 4, were used to assess the financial impacts to the ultimate corporate owners of oil and natural gas production facilities.

As a result of the regulations, companies will potentially experience changes in the costs of oil and natural gas production as well as changes in the revenues generated by providing these products. Both cost and revenue impacts may be either positive or negative. The cost and revenue changes projected to result from regulating each source category occur at the facility level as a result of market adjustments. Net changes in company profitability are derived by summing facility cost and revenue changes across all facilities owned by each affected company. The net impact on a company's profitability may be negative (cost increases exceed revenue increases) or positive (revenue increases exceed cost increases).

Figure 5-1 characterizes owners' potential responses to regulatory actions. The shaded areas represent decisions made at the facility level that are used as inputs to the company-level analysis. For this analysis, companies are projected to implement the cost-minimizing compliance option and continue to operate their facilities. As long as the company continues to meet its debt obligations, operations will continue. Realistically, if the company cannot meet its interest payments or is in violation of its debt covenants, the company's creditors may take control of the exit decision and forced exit may occur. If the market value of debt (DM) under continued operations is greater than the liquidation value of debt (DL), creditors would probably allow the facility to continue to operate. Under these conditions, creditors may renegotiate the terms of debt. If, however, the DM under continued operations is less than DL, involuntary exit will result and the facility will discontinue operations. Exit will likely take the form of liquidation of assets or distressed sale of the facility. These decisions are modeled in terms of their financial impact to parent companies. The decision to continue to operate may be accompanied by a change in the financial viability of the company.

5.2 FINANCIAL IMPACTS OF THE REGULATION

This analysis evaluates the change in financial status by computing the with-regulation financial ratios of potentially affected firms and comparing them to the corresponding baseline ratios. These financial ratios may include indicators of liquidity, asset management, debt management, and profitability. Although a variety of possible financial ratios provide individual indicators of a firm's health, they may not all give the same signals. Therefore, this analysis focuses on changes in key measures of profitability (return on sales, the return on assets, and the return on equity).

Contains Data for

Postscript Only.

Figure 5-1. Characterization of owner responses to regulatory action.

To assess the financial impacts on the oil and natural gas production source category, this analysis characterizes the financial status of a sample of 80 public firms potentially affected by the regulation. Based on SBA size standards from Table 5-1, a total of 39 firms in this sample are defined as small, or 48.8 percent. Baseline financial statements are developed based on financial information reported in the OGJ and industry-level financial ratios from Dun and Bradstreet (D&B). To compute the with-regulation financial ratios, pro-forma income statements and balance sheets reflecting the with-regulation condition of potentially affected firms were developed based on projected with-regulation costs (including compliance costs) and revenues (including product recovery credits and the with-regulation price and quantity changes projected using a market model).

The financial impacts on the natural gas transmission source category are not assessed because no small entities are expected to be affected. Only operations with throughput of 500 MMcfd or more will be affected by the rule.[2] Information reported in OGJ for the 110 largest gas pipeline companies indicates that none of the companies with volumes in the 500 MMcfd range would have qualified as small businesses (less than $5 million in revenues) in 1994.[1] For the 34 companies that did transmit volumes in that range in 1994, even if all 5 of the TEG units expected to be affected by the rule were operated by the firm with the smallest revenues, the annual compliance costs would only represent 0.34 percent of its revenues.

5.2.1 Baseline Financial Statements

[2]Based on model TEG units in Class E.

Pro-forma income statements and balance sheets reflecting the 1993 baseline condition of 80 potentially affected firms were developed based on financial information reported in the OGJ and industry-level financial ratios from D&B.[2,3] This analysis includes 49 firms that listed 1311 as their primary SIC code, 8 firms under SIC 1382, 14 firms under SIC 2911, 8 firms under SIC 4922, and 1 firm under SIC 4924. Each of these firms is publicly traded and listed in the OGJ300, which includes estimates of total revenue, net income, total assets, and shareholder equity. The remaining financial variables needed to complete each firm's income statement and balance sheet were computed using financial ratios computed from the OGJ data and from the D&B benchmark financial ratios shown in Table 5-2. Appendix F provides more detailed firm-by-firm financial data for the 80 sample firms.

This analysis employed probability distributions of the D&B benchmark ratios rather than point estimates to compute the remaining financial variables. The probability distributions for each financial ratio listed in Table 5-2 were generated using @RISK, a risk analysis software add-on for Lotus 1-2-3. In projecting the baseline financial statements, the D&B benchmark ratios were modeled as a triangular distribution with the median value reflecting the most likely value of the distribution and the lower and upper quartile values reflecting the 25th and 75th percentile values of the distribution. @RISK randomly selected a value from the probability distribution of each financial ratio and combined these values with the OGJ data to project the baseline income statement and balance sheet for each firm.

5.2.2 With-Regulation Financial Statements

Before adjusting the baseline financial statements, the regulatory control costs must be mapped from processing facilities to the firms that own them. Mapping the regulatory costs to firms requires knowledge of the number of processing facilities owned by each firm and the extent that they are

TABLE 5-2. DUN AND BRADSTREET'S BENCHMARK FINANCIAL RATIOS BY SIC CODE FOR THE OIL AND NATURAL GAS PRODUCTION INDUSTRY

SIC code/financial ratio	Lower quartile	Median	Upper quartile
1311-Crude Petroleum and Natural Gas			
Quick ratio (times)	0.6	1.1	2.3
Current ratio (times)	0.8	1.5	3.5
Current liab. to net worth (%)	84.0	30.9	9.7
Fixed assets to net worth (%)	133.5	64.0	22.2
1381-Drilling Oil and Gas Wells			
Quick ratio (times)	0.8	1.3	2.7
Current ratio (times)	1.0	1.7	4.2
Current liab. to net worth (%)	92.8	37.1	11.2
Fixed assets to net worth (%)	123.5	74.6	27.5
1382-Oil and Gas Exploration Services			
Quick ratio (times)	0.5	1.0	1.9
Current ratio (times)	0.8	1.3	3.4
Current liab. to net worth (%)	77.3	33.4	10.0
Fixed assets to net worth (%)	129.9	70.0	22.3
2911-Petroleum Refining			
Quick ratio (times)	0.5	0.7	0.9
Current ratio (times)	1.1	1.3	1.9
Current liab. to net worth (%)	97.9	68.3	37.7
Fixed assets to net worth (%)	220.1	169.9	103.8
4922-Natural Gas Transmission			
Quick ratio (times)	0.3	0.7	1.0
Current ratio (times)	0.8	1.0	1.5
Current liab. to net worth (%)	105.9	50.7	29.4
Fixed assets to net worth (%)	264.7	175.7	111.4

(continued)

TABLE 5-2. DUN AND BRADSTREET'S BENCHMARK FINANCIAL RATIOS BY SIC CODE FOR THE OIL AND NATURAL GAS PRODUCTION INDUSTRY (CONTINUED)

SIC code/financial ratio	Lower quartile	Median	Upper quartile
4923-Gas Transmission and Distribution			
Quick ratio (times)	0.3	0.7	1.1
Current ratio (times)	0.7	1.0	1.4
Current liab. to net worth (%)	127.6	65.6	30.4
Fixed assets to net worth (%)	229.3	144.3	104.8
4924-Natural Gas Distribution			
Quick ratio (times)	0.4	0.7	1.1
Current ratio (times)	0.8	1.0	1.4
Current liab. to net worth (%)	99.2	57.9	35.4
Fixed assets to net worth (%)	225.0	176.9	86.8

Source: Dun's Analytical Services. Industry Norms and Key Business Ratios. Dun and Bradstreet, Inc. 1994.

affected by the regulation. The market model did not explicitly link firms to their respective processing facilities. Thus, this analysis relies on firm responses to EPA's Air Emissions Survey Questionnaires to determine ownership of TEG dehydration units and condensate tank batteries and the OGJ's Special Report, "Worldwide Gas Processing," to determine ownership of natural gas processing plants operating in the U.S. as of January 1994.[4]

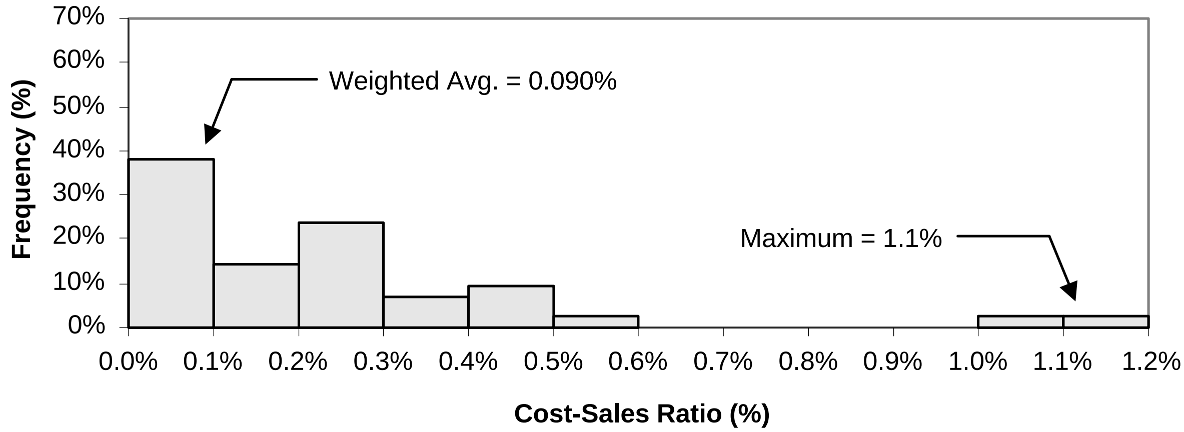
Table 5-3 provides the ratio of model TEG units to total assets as computed from the EPA survey data. These ratios reflect the average of firms within the natural gas production groups as defined in the table. To estimate the number of model TEG units for each firm, the total assets of the firm were multiplied by the appropriate ratios. The number of model CTBs for each firm was estimated according to the ratio of CTBs to TEG units by model type. In addition, the number

TABLE 5-3. DISTRIBUTION OF MODEL TEG UNITS BY FIRM'S LEVEL OF NATURAL GAS PRODUCTION

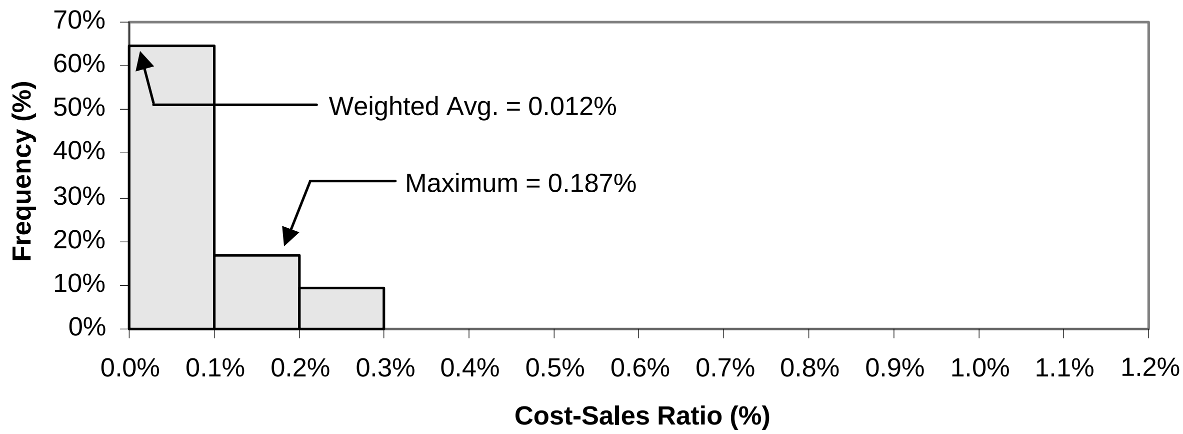
Natural gas production	Model TEG units per ($$10^6$) of assets			
	A	B	C	D
>500 Bcf	0.30259	0.05663	0.00890	0.00405
175 to 500 Bcf	0.40071	0.07447	0.00355	0.00532
100 to 175 Bcf	0.36200	0.09000	0.00600	0.01800
10 to 100 Bcf	0.41223	0.02660	0.00000	0.00665
<10 Bcf	1.15830	0.00000	0.00000	0.00000

of model natural gas processing plants owned by each firm was estimated given the company name and 1993 throughput of natural gas as provided in the OGJ.

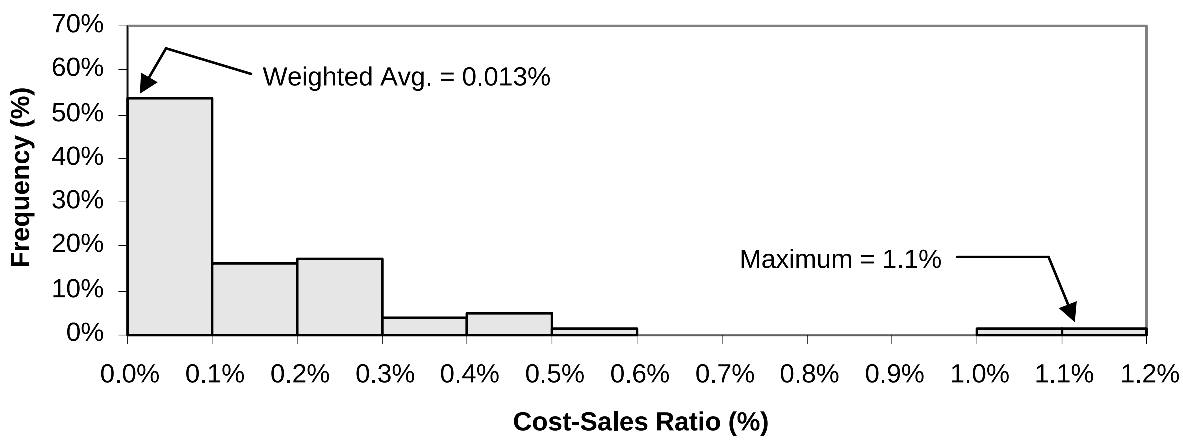
In the absence of information on the number of affected units owned by each firm, this analysis assumed that each TEG unit, CTB, and processing plant owned by each firm is expected to be affected by the regulation--the worst-case scenario for each firm. Affected firms typically incur three types of costs because of regulation: capital, operating, and administrative. The capital cost is an initial lump sum associated with purchasing and installing pollution control equipment. Operating costs are the annually recurring costs associated with operation and maintenance of control equipment, while administrative costs are annually recurring costs associated with emission monitoring, reporting, and recordkeeping. Figure 5-2 provides an indication of the burden of the regulatory costs on sample firms in the oil and natural gas production source category by size. This figure shows the distribution of total annual compliance cost (annualized capital plus the annual operating and administrative cost) as a percentage of baseline sales across sample firms by size. As shown, the mean level of regulatory burden for small firms in the sample if 0.09 percent of sales



(a) Small Companies



(b) Large Companies



(c) Total, All Companies

Figure 5-2. Distribution of total annual compliance cost to sales ratio for sample companies.

with a maximum level of 1.1 percent of sales. Alternatively, the mean level of regulatory burden for large firms in the sample is 0.01 percent of sales with a maximum level of 0.19 percent.

Several adjustments were made to the baseline financial statements of each firm to account for the regulation-induced changes at all facilities owned by the firm. Table 5-4 shows the adjustments made to the baseline financial statements to develop the with-regulation financial statements that form the basis of this analysis.

In the annual income statement, the baseline annual revenues are increased by the projected product recovery credits earned by each firm and by the expected change in operating revenues of less than 0.01 percent based on the regulation induced market adjustments. Furthermore, the baseline operating expenses are increased by the estimated change in operating and maintenance costs across TEG units and NGPPs owned by the firm, while the firms' other expenses also increase due to the interest charges and depreciation associated with the acquired pollution control equipment.

In the balance sheet, changes occur to only those firms that incur capital control costs and are determined by the manner in which firms acquire the pollution control equipment. These firms face three choices in funding the acquisition of capital equipment required to comply with the regulation. These choices are

- debt financing,
- equity financing, or
- a mixture of debt and equity financing.

Debt financing involves obtaining additional funds from lenders who are not owners of the firm: they include buyers of bonds, banks, or other lending institutions. Compliance

TABLE 5-4. CALCULATIONS REQUIRED TO SET UP WITH-REGULATION FINANCIAL STATEMENTS

Financial statement category	Calculations
Income statement	
Annual revenues	Baseline annual revenues + product recovery credits + projected revenue change due to market adjustments.
Cost of sales	Baseline cost of sales + operating and maintenance cost of regulation.
Gross profit	Annual revenues – cost of sales.
Expenses due to regulation	Interest: Projected share of capital costs financed through debt times the debt interest rate (7%). Depreciation: 7.5% times the annualized capital costs.
Other expenses and taxes	(Gross profit – estimated expense due to regulation) times the baseline ratio of other expenses and taxes to gross profit.
Net income	Gross profit – estimated expense due to regulation – other expenses and taxes.
Balance sheet	
Current assets	Baseline current assets – [(1 – debt ratio) times total capital cost].
Fixed assets	Baseline fixed assets + total capital cost.
Other noncurrent assets	No change from baseline.
Total assets	Current assets + fixed assets + other noncurrent assets.
Current liabilities	Baseline current liabilities + amortized compliance cost financed through debt – estimated interest expense.
Noncurrent liabilities	Baseline noncurrent liabilities + (debt ratio times total capital cost) – current portion of debt.
Total liabilities	Current liabilities + noncurrent liabilities.
Net worth	Total assets – total liabilities.

Note: Depreciation expense is based on the first year's allowable deduction for industrial equipment under the modified accelerated cost recovery system.

costs not financed through debt are financed using internal or external equity. Internal equity includes the current portion of the company's retained earnings that are not distributed in the form of dividends to the owners (shareholders) of the company, while external equity refers to newly issued equity shares. Each source differs in its exposure to risk, its taxation, and its costs. In general, debt financing is more risky for the firm than equity financing because of the legal obligation of repayment, while borrowing debt can allow a firm to reduce its weighted average cost of capital because of the deductibility of interest on debt for State and Federal income tax purposes. The outcome is that a tradeoff associated with debt financing for each firm exists and it depends on the firm’s tax rates, its asset structures, and their inherent riskiness.

Leverage indicates the degree to which a firm's assets have been supplied by, and hence are owned by, creditors versus owners. Leverage should be in an acceptable range, indicating that the firm is using enough debt financing to take advantage of the low cost of debt, but not so much that current or potential creditors are uneasy about the ability of the firm to repay its debt. The debt ratio (d) is a common measure of leverage that divides all debt, long and short term, by total assets. Empirical evidence shows that capital structure can vary widely from the theoretical optimum and yet have little impact on the value of the firm.[5] Consequently, it was assumed that the current capital structure, as measured by the debt ratio, reflects the optimal capital structure for each firm. Thus, for this analysis, each firm's debt ratio for 1993 determines the amount of capital expenditures on pollution control technology that will be debt financed. That portion not debt financed is assumed to be financed using internal equity.

Thus, on the assets side of the balance sheet of affected firms, current assets decline by (1-d) times the total capital cost (E^K), while the value of property, plant, and equipment (fixed assets) increases by the total capital cost (i.e., the value of the pollution control equipment). Thus, the overall increase in a firm's total assets is equal to that fraction of the total capital cost that is not paid out of current assets (i.e., $d*E^K$).

The liabilities side of the balance sheet is affected because firms enter new legal obligations to repay that fraction of the total capital cost that is assumed to be debt financed (i.e., $d*E^K$). Long-term debt, and thus total liabilities, of the firm is increased by this dollar amount less the interest expense paid during the year. Owner's equity, or net worth at these firms, is increased by only the amount of interest expense paid during the year due to the offsetting increases in both total assets and total liabilities regarding the acquisition of the pollution control equipment. Moreover, working capital at each affected firm, defined as current assets minus current liabilities, unambiguously falls because of the decline in current assets and the increase in current liabilities.

Comparison of the baseline and with-regulation financial statements of firms in the U.S. oil and natural gas production industry provides indicators of the potential disparity of economic impacts across small and large firms. These indicators include the key measures of profitability (return on sales, return on assets, and return on equity) and changes in the likelihood of financial failure or bankruptcy (as measured by Altman's Z-score).

5.2.3 Profitability Analysis

Financial ratios may be categorized as one of five fundamental types:

- liquidity or solvency
- asset management
- debt management
- profitability
- market value[6]

Profitability is the most comprehensive measure of the firm's performance because it measures the combined effects of liquidity, asset management, and debt management. Analyzing profitability is useful because it helps evaluate both the incentive and ability of firms in the oil and natural gas production industry to incur the capital and operating costs required for compliance. More profitable firms have more incentive than less profitable firms to comply because the annual returns to doing business are greater. In the extreme, a single-facility firm earning zero profit has no incentive to comply with a regulation imposing positive costs unless the entire burden of the regulation can be passed along to consumers. This same firm may also be less able to comply because its poor financial position makes it difficult to obtain funds through either debt or equity financing.

As shown in Table 5-5, three ratios are commonly used to measure profitability: return on sales, return on assets, and return on equity. For all these measures, higher values are unambiguously preferred over lower values. Negative values result if the firm experiences a loss.

TABLE 5-5. KEY MEASURES OF PROFITABILITY

Measure of profitability	Formula for calculation
Return on sales	$\frac{\text{Net income}}{\text{Sales}}$
Return on assets	$\frac{\text{Net income}}{\text{Total assets}}$
Return on equity	$\frac{\text{Net income}}{\text{Owner's equity}}$

Table 5-6 provides the summary statistics for each of the measures of profitability. The summary statistics include the mean, minimum, and maximum values for each measure in the baseline and with-regulation conditions across small, large, and all firms included in this analysis. A comparison of the values in baseline and after imposition of the regulation provides much detail on the distributional changes in these profitability measures across firms.

TABLE 5-6. SUMMARY STATISTICS FOR KEY MEASURES OF PROFITABILITY IN BASELINE AND WITH-REGULATION BY FIRM SIZE CATEGORY

Measure of profitability/summary statistics	Baseline			With regulation		
	Small firms	Large firms	All firms	Small firms	Large firms	All firms
Return on sales						
Mean	8.05	3.71	5.82	7.87	3.66	5.71
Minimum	-43.99	-17.29		-44.30	-17.33	
Maximum	70.15	29.47		69.82	29.30	
Return on assets						
Mean	5.83	2.72	4.24	5.76	2.70	4.19
Minimum	-10.34	-7.16		-10.42	-7.18	
Maximum	62.22	16.59		62.22	16.49	

Return on equity						
Mean	9.00	6.16	7.54	8.80	6.10	7.41
Minimum	-91.37	-33.40		-91.78	-33.64	
Maximum	90.35	26.43		89.85	26.26	

As Table 5-6 illustrates, the mean return on sales slightly declines for all firms after imposition of the regulation from 5.82 percent to 5.71 percent. This slight decline is shared across small and large firms. Further, the mean return on assets declines to some extent for all firms with regulation from 4.24 percent to 4.19 percent. This inconsiderable decline in the mean return on assets is found for small and large firms alike. As measured across all firms, the with-regulation mean return on equity declines slightly from 7.54 percent to 7.41 percent. As a group, the financial impacts associated with the regulation are negligible and show no overall disproportionate impact across small and large firms.

The screening analysis of the transmission and storage firms in section 4.3.2.2 shows that the cost-to-revenues ratios of the selected firms is 0.09% on average, which indicates that impacts are typically well below 1/10th of one percent for these firms.

Therefore, this information presented in this section of the EIA along with the screening analysis of the transmission and storage firms in section 4.3.2.2 clearly indicates that there will not be a significant impact on a substantial number of small entities in the natural gas production, and transmission and storage industries.

References:

1. Ref. 49.

2. Ref. 46.

3. Ref. 76.

4. Ref. 39.

5. Brigham, Eugene F., and Louis C. Gapenski. Financial Management: Theory and Practice. 6th Ed. Orlando, FL, The Dryden Press. 1991.

6. Ref. 82.