

2. Natural Gas and the Environment

Currently, natural gas represents 24 percent of the energy consumed in the United States. The Energy Information Administration (EIA) *Annual Energy Outlook 1999* projects that this figure will increase to about 28 percent by 2020 under the reference case as consumption of natural gas is projected to increase to 32.3 trillion cubic feet. In addition, a recent EIA Service Report, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity*, indicates that the use of natural gas could be even 6 to 10 percent higher in 2020 if the United States adopts the Kyoto Protocol's requirement to reduce carbon emissions by 7 percent from their 1990 levels by the 2008–2012 time period, without other changes in laws, regulations, and policies. These increases are expected because emissions of greenhouse gases are much lower with the consumption of natural gas relative to other fossil fuel consumption. For instance:

- Natural gas, when burned, emits lower quantities of greenhouse gases and criteria pollutants per unit of energy produced than do other fossil fuels. This occurs in part because natural gas is more easily fully combusted, and in part because natural gas contains fewer impurities than any other fossil fuel. For example, U.S. coal contains 1.6 percent sulfur (a consumption-weighted national average) by weight. The oil burned at electric utility power plants ranges from 0.5 to 1.4 percent sulfur. Diesel fuel has less than 0.05 percent, while the current national average for motor gasoline is 0.034 percent sulfur. Comparatively, natural gas at the burner tip has less than 0.0005 percent sulfur compounds.
- The amount of carbon dioxide produced for an equivalent amount of heat production varies substantially among the fossil fuels, with natural gas producing the least. On a carbon-equivalent basis, energy-related carbon dioxide emissions accounted for 83.8 percent of U.S. anthropogenic greenhouse gas emissions in 1997. For the major fossil fuels, the amounts of carbon dioxide produced for each billion Btu of heat energy extracted are: 208,000 pounds for coal, 164,000 pounds for petroleum products, and 117,000 pounds for natural gas.

Other aspects of the development and use of natural gas need to be considered as well in looking at the environmental consequences related to natural gas. For example:

- The major constituent of natural gas, methane, also directly contributes to the greenhouse effect through venting or leaking of natural gas into the atmosphere. This is because methane is 21 times as effective in trapping heat as is carbon dioxide. Although methane emissions amount to only 0.5 percent of U.S. emissions of carbon dioxide, they account for about 10 percent of the greenhouse effect of U.S. emissions.
- A major transportation-related environmental advantage of natural gas is that it is not a source of toxic spills. But, because there are about 300,000 miles of high-pressure transmission pipelines in the United States and its offshore areas, there are corollary impacts. For instance, the construction right-of-way on land commonly requires a width of 75 to 100 feet along the length of the pipeline; this is the area disturbed by trenching, soil storage, pipe storage, vehicle movement, etc. This area represents between 9.1 and 12.1 acres per mile of pipe which is, or has been, subject to intrusion.

Natural gas is seen by many as an important fuel in initiatives to address environmental concerns. Although natural gas is the most benign of the fossil fuels in terms of air pollution, it is less so than nonfossil-based energy sources such as renewables or nuclear power. However, because of its lower costs, greater resources, and existing infrastructure, natural gas is projected to increase its share of energy consumption relative to all other fuels, fossil and nonfossil, under current laws and regulations.

The vast majority of U.S. energy use comes from the combustion of fossil hydrocarbon fuels. This unavoidably results in a degree of air, land, and water pollution, and the production of greenhouse gases that might contribute to

global warming and certain public health risks. To address these health and environmental concerns, the United States has many laws and regulations in place that are designed to control and/or reduce pollution. In the United States,

natural gas use is projected to increase nearly 50 percent by 2020.¹ This is because North American natural gas resources are considered both plentiful and secure, are expected to be competitively priced, and their increased use can be effective in reducing the emission of pollutants.

While the use of natural gas does have environmental consequences, it is attractive because it is relatively clean-burning. This chapter discusses many environmental aspects related to the use of natural gas, including the environmental impact of natural gas relative to other fossil fuels and some of the potential applications for increased use of natural gas. On the other hand, the venting or leaking of natural gas into the atmosphere can have a significant effect with respect to greenhouse gases because methane, the principal component of natural gas, is much more effective in trapping these gases than carbon dioxide. The exploration, production, and transmission of natural gas, as well, can have adverse effects on the environment. This chapter addresses the level and extent of some of these impacts on the environment.

Air Pollutants and Greenhouse Gases

The Earth's atmosphere is a mixture primarily of the gases nitrogen and oxygen, totaling 99 percent; nearly 1 percent water; and very small amounts of other gases and substances, some of which are chemically reactive. With the exception of oxygen, nitrogen, water, and the inert gases, all constituents of air may be a source of concern owing either to their potential health effects on humans, animals, and plants, or to their influence on the climate.

As mandated by The Clean Air Act (CAA), which was last amended in 1990, the Environmental Protection Agency (EPA) regulates "criteria pollutants" that are considered harmful to the environment and public health:

- **Gases.** The gaseous criteria pollutants are carbon monoxide, nitrogen oxides, volatile organic compounds,² and sulfur dioxide (Figure 20). These are reactive gases that in the presence of sunlight contribute to the formation of ground level ozone, smog, and acid rain.

¹Energy Information Administration, *Annual Energy Outlook 1999*, DOE/EIA-0383(99) (Washington, DC, December 1998).

²Note that methane, the principal ingredient in natural gas, is not classed as a volatile organic compound because it is not as chemically reactive as the other hydrocarbons, although it is a greenhouse gas.

- **Particulates.** The nongaseous criteria pollutant particulate matter consists of metals and substances such as pollen, dust, yeast, mold, very tiny organisms such as mites and aerosolized liquids, and larger particles such as soot from wood fires or diesel fuel ignition.
- **Air Toxics.** The CAA identifies 188 substances as air toxics or hazardous air pollutants, with lead being the only one that is currently classified as a criteria pollutant and thus regulated. Air toxic pollutants are more acute biological hazards than most particulate or criteria pollutants but are much smaller in volume. Procedures are now underway to regulate other air toxics under the CAA.

The greenhouse gases are water vapor, carbon dioxide, methane, nitrous oxide, and a host of engineered chemicals, such as chlorofluorocarbons (Figure 21). These gases regulate the Earth's temperature. When the natural balance of the atmosphere is disturbed, particularly by an increase or decrease in the greenhouse gases, the Earth's climate could be affected.

The combustion of fossil fuels produces 84 percent of U.S. anthropogenic (created by humans) greenhouse emissions.³ When wood burning is included, these fuels produce 95 percent of the nitrogen oxides, 94 percent of the carbon monoxide, and 93 percent of the sulfur dioxide criteria pollutants (Figure 20). Most of these emissions are released into the atmosphere as a result of fossil fuel use in industrial boilers and power plants and in motor vehicles.

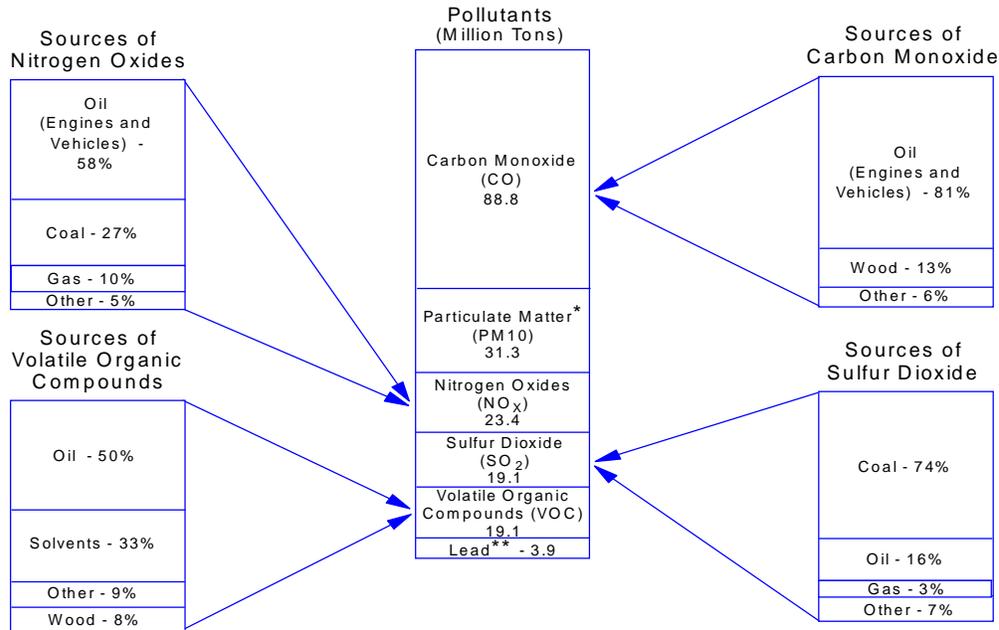
Emissions from Burning Natural Gas

Natural gas is less chemically complex than other fuels, has fewer impurities, and its combustion accordingly results in less pollution. Natural gas consists primarily of methane (see box, p. 52). In the simplest case, complete combustive reaction of a molecule of pure methane (which comprises one carbon atom and four hydrogen atoms) with two molecules of pure oxygen produces a molecule of carbon dioxide gas, two molecules of water in vapor form, and heat.⁴ In practice, however, the combustion process is never

³Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1997*, DOE/EIA-0573(97) (Washington, DC, October 1998).

⁴As described by $\text{CH}_4 + 2 \text{O}_2 \rightarrow \text{CO}_2 + 2 \text{H}_2\text{O} + \text{heat}$.

Figure 20. U.S. Criteria Pollutants and Their Major Sources, 1996

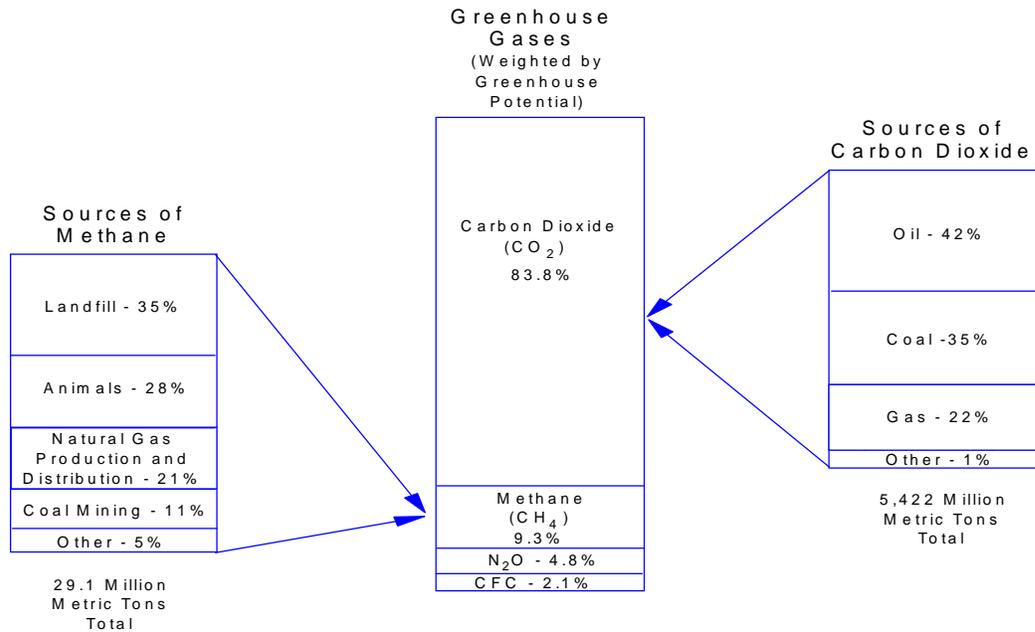


*Wood and other fuels account for only 9 percent of particulate matter.

**Oil accounts for 25 percent of lead and other fuels 2 percent.

Source: Energy Information Administration, Office of Oil and Gas, derived from: Environmental Protection Agency, *National Air Pollutant Emission Trends 1990-1996*, Appendix A (December 1997).

Figure 21. U.S. Anthropogenic Greenhouse Gases and Their Sources, 1997



N₂O = Nitrous oxide. CFC = Chlorofluorocarbon.

Source: Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1997* (October 1998).

Sources and Chemical Composition of Natural Gas

Natural gas is obtained principally from conventional crude oil and nonassociated gas reservoirs, and secondarily from coal beds, tight sandstones, and Devonian shales. Some is also produced from minor sources such as landfills. In the future, it may also be obtained from natural gas hydrate deposits located beneath the sea floor in deep water on the continental shelves or associated with thick subsurface permafrost zones in the Arctic.

Natural gas is a mixture of low molecular-weight aliphatic (straight chain) hydrocarbon compounds that are gases at surface pressure and temperature conditions. At the pressure and temperature conditions of the source reservoir, it may occur as free gas (bubbles) or be dissolved in either crude oil or brine. While the primary constituent of natural gas is methane (CH₄), it may contain smaller amounts of other hydrocarbons, such as ethane (C₂H₆) and various isomers of propane (C₃H₈), butane (C₄H₁₀), and the pentanes (C₅H₁₂), as well as trace amounts of heavier hydrocarbons. Nonhydrocarbon gases, such as carbon dioxide (CO₂), helium (He), hydrogen sulfide (H₂S), nitrogen (N₂), and water vapor (H₂O), may also be present in any proportion to the total hydrocarbon content.

Pipeline-quality natural gas contains at least 80 percent methane and has a minimum heat content of 870 Btu per standard cubic foot. Most pipeline natural gas significantly exceeds both minimum specifications. Since natural gas has by far the lowest energy density of the common hydrocarbon fuels, by volume (not weight) much more of it must be used to provide a given amount of energy. Natural gas is also much less physically dense, weighing about half as much (55 percent) as the same volume of dry air at the same pressure. It is consequently buoyant in air, in which it is also combustible at concentrations ranging from 5 percent to 15 percent by volume.

that perfect as it takes place in air rather than in pure oxygen, resulting in some pollutants.⁵

The reaction products include particulate carbon, carbon monoxide, and nitrogen oxides, in addition to carbon dioxide, water vapor, and heat. Carbon monoxide, the nitrogen oxides, and particulate carbon are criteria pollutants (regulated emissions). The proportions of the reaction products are determined by the efficiency of combustion. For instance, when the air supply to a gas burner is not adequate, the produced levels of carbon monoxide and other pollutants are greater. This situation is, of course, similar to that of all other fossil hydrocarbon fuels—insufficient oxygen supply to the burner will inevitably result in incomplete combustion and the consequent production of carbon monoxide and other pollutants.

Since natural gas is never pure methane and air is not just oxygen and nitrogen, small amounts of additional pollutants are also generated during combustion of natural

gas. For example, all fossil fuels contain sulfur; its removal from both oil and gas is a major part of the processing of these fuels prior to distribution. However, not all sulfur is removed during processing. When the fuel is burned, several oxides of sulfur are produced, consisting primarily of sulfur dioxide, some other sulfur-bearing acids, and traces of many other sulfur compounds depending on what other trace compounds are present in the fuel. Additionally, since natural gas is both colorless and odorless, sulfur-bearing odorants⁶ are intentionally added to the gas stream by gas distributors so that residential consumers can smell a leak. Besides sulfur, natural gas can include other trace impurities and contaminants.⁷

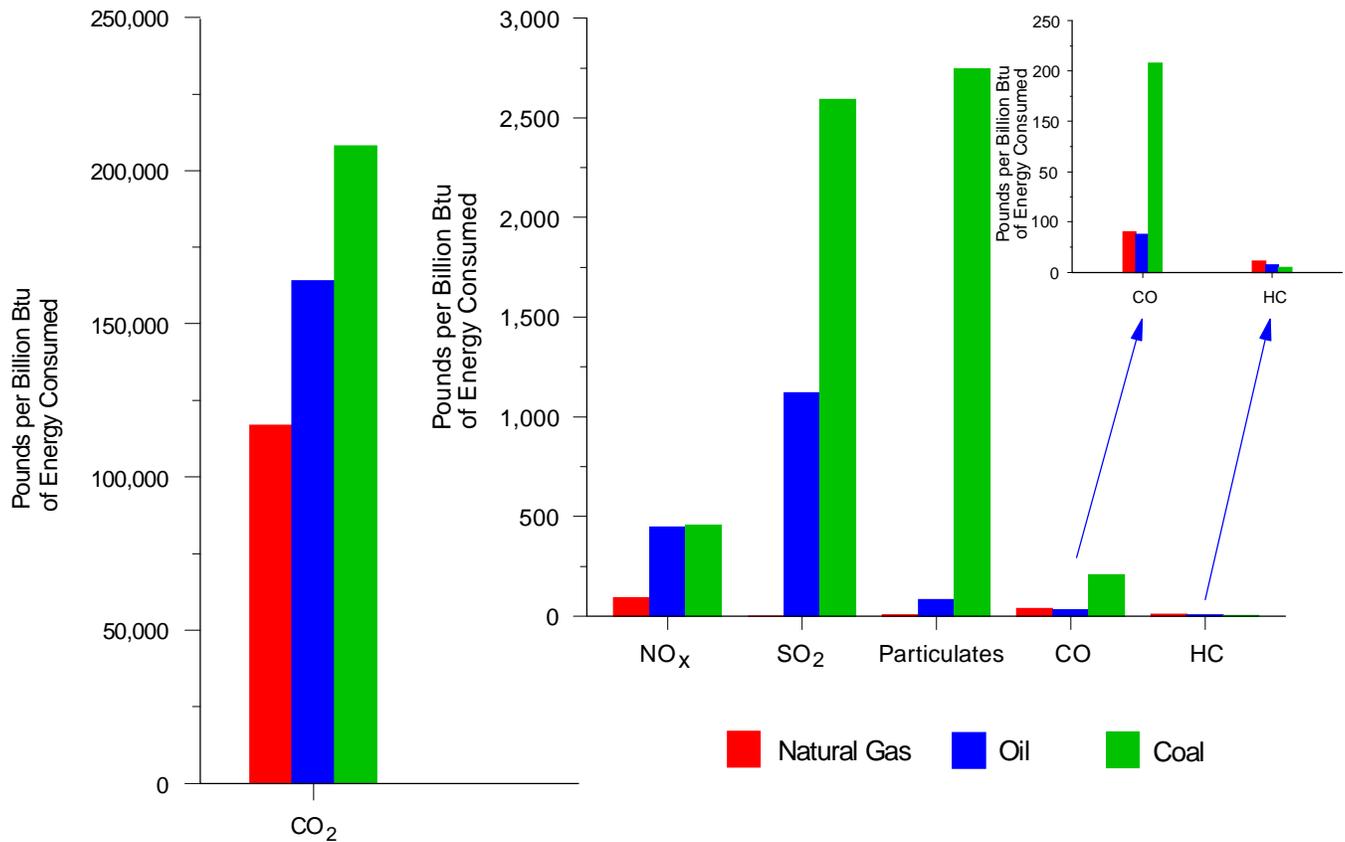
Yet the emittable pollutants resulting from combustion of natural gas are far fewer in volume and number than those from the combustion of any other fossil fuel (Figure 22). This occurs in part because natural gas is more easily fully combusted, and in part because natural gas has fewer impurities than other hydrocarbon fuels. For example, the amount of sulfur in natural gas is much less than that of

⁵Since the process takes place in air rather than pure oxygen, the practical result is more like: CH₄ + O₂ + N₂ → C + CO + CO₂ + N₂O + NO + NO₂ + H₂O + CH₄ (unburned) + heat (exact proportions depend on the prevailing combustion conditions).

⁶These odorants are compounds such as dimethyl sulfide, tertiary butyl mercaptan, tetrahydrothiophene, and methyl mercaptan.

⁷Trace impurities can include radon, benzene, toluene, ethylbenzene, xylene, and organometallic compounds such as methyl mercury. The list of combustion byproducts can include fine particulate matter, polycyclic aromatic hydrocarbons, and volatile organic compounds including formaldehyde.

Figure 22. Air Pollutant Emissions by Fuel Type



CO₂ = Carbon dioxide. NO_x = Nitrogen oxides. SO₂ = Sulfur dioxide. CO = Carbon monoxide. HC = Hydrocarbon.
 Note: Graphs should not be directly compared because vertical scales differ.

Source: Energy Information Administration (EIA) Office of Oil and Gas. **Carbon Monoxide:** derived from EIA, *Emissions of Greenhouse Gases in the United States 1997*, Table B1, p. 106. **Other Pollutants:** derived from Environmental Protection Agency, *Compilation of Air Pollutant Emission Factors*, Vol. 1 (1998). Based on conversion factors derived from EIA, *Cost and Quality of Fuels for Electric Utility Plants* (1996).

coal or oil. U.S. coals contain an average of 1.6 percent sulfur by weight,⁸ and the oil burned at electric utility power plants ranges from 0.5 percent to 1.4 percent sulfur.⁹ Diesel fuel has less than 0.05 percent sulfur by weight (or 500 parts per million (ppm)) and the current national average for motor gasoline is 340 ppm sulfur (includes California where the regulated statewide average is 30 ppm).¹⁰ Comparatively, natural gas at the burner tip has less than 5 ppm of all sulfur compounds, typically

comprising about 1 ppm hydrogen sulfide and less than 2 ppm of each sulfur-bearing odorant.¹¹

Toxic and Particulate Emissions

The combustion of natural gas also produces significantly lower quantities of other undesirable compounds,

⁸U.S. coals burned at Clean Air Act Phase I electric power plants contain an average of 0.3 percent sulfur for western coals and 2.5 percent for eastern coals, yielding a consumption-weighted national average of 1.6 percent sulfur by weight.

⁹Energy Information Administration, *Electric Power Annual, 1996*, Vol. 2, DOE/EIA-348(96) (Washington, DC, 1997), p. 41.

¹⁰Gerald Karey, "EPA leaves sulfur verdict for another day," *Platts Oilgram News*, 76/78 (April 24, 1998), p. 4.

¹¹Washington Gas Light Company personnel stated that its system hydrogen sulfide (H₂S) levels are 1.8 parts per million (ppm) and the sulfur-bearing odorants are 2.0 ppm. Institute for Gas Technology tests of trace constituents in two intrastate pipeline samples and two Canadian interstate samples supplied by the Pacific Gas and Electric Company had less than 5 ppm total H₂S (usually between 1 and 1.5 ppm). Sulfur content by contract for pipeline-quality natural gas varies from 0.25 grains to 1.0 grain per 100 standard cubic feet (1.9 ppm to 7.6 ppm), in many cases 0.25 grains or 1.9 ppm. Dr. John M. Campbell, Chapter 7, "Product Specifications," *Gas Conditioning and Processing*, Vol. 1 (Norman, OK, 1979).

particularly toxics, than those produced from combustion of petroleum products or coal. Toxic air pollutants are those compounds that are not specifically covered under other portions of the CAA (i.e., the criteria pollutants and particulate matter) and are typically carcinogens, reproductive toxics, and mutagens. The United States emits 2.7 billion pounds of toxics into the atmosphere each year. Motor vehicles are the primary source, followed by residential wood combustion. Section 112 of the CAA of 1990 lists 188 toxic compounds or groups as hazardous air pollutants (HAPs), including various compounds of mercury, arsenic, lead, nickel, and beryllium and also organic compounds, such as toluene, benzene, formaldehyde, chloroform, and phosgene, which are expected to be regulated soon. Presently, only lead is regulated.

The toxic compound benzene can be a component of both petroleum products and natural gas, but whereas it can comprise up to 1.5 percent by weight of motor gasoline, the levels in natural gas are considered insignificant and are not generally monitored by gas-processing plants and most pipeline companies.¹² As required by California Proposition 65, the Safe Drinking Water and Toxic Enforcement Act, gas pipeline companies that operate in California continuously monitor for toxic substances. These companies have found that the benzene and toluene content of the natural gas they carry varies by source and can range from less than 0.4 ppm to 6 ppm for interstate gas and up to 100 ppm for intrastate gas.¹³ Depending on the efficiency of the combustion, some will be oxidized to carbon dioxide and water, some will pass through unburned, and some will be converted to other toxic compounds.

The particulates produced by natural gas combustion are usually less than 1 micrometer (micron) in diameter and are composed of low molecular-weight hydrocarbons that are not fully combusted.¹⁴ Typically, combustion of the other fossil fuels produces greater volumes of larger and more complex particulates. In 1998, the Environmental Protection Agency set a new standard for very fine (less than 2.5 microns) particulates as an add-on to the existing regulation of suspended particulates that are 10 microns or

larger, set in 1987.¹⁵ Although power plants and diesel-powered trucks and buses are major emitters of particulate matter, the bulk of 10-micron-plus particulate matter emissions is composed of “fugitive” dust from roadways (58 percent) and combined sources of agricultural operations and wind erosion (30 percent).¹⁶

Acid Rain and Smog Formation

Natural gas is not a significant contributor to acid rain formation. Acid rain is formed when sulfur dioxide and the nitrogen oxides chemically react with water vapor and oxidants in the presence of sunlight to produce various acidic compounds, such as sulfuric acid and nitric acid. Electric utility plants generate about 70 percent of SO₂ emissions and 30 percent of NO_x emissions in the United States; motor vehicles are the second largest source of both. Natural gas is responsible for only 3 percent of sulfur dioxide and 10 percent of nitrogen oxides (Figure 20). Precipitation in the form of rain, snow, ice, and fog causes about half of these atmospheric acids to fall to the ground as “acid rain,” while about half fall as dry particles and gases. Winds can blow the particles and compounds hundreds of miles from their source before they are deposited, and they and their sulfate and nitrate derivatives contribute to atmospheric haze prior to eventual deposition as acid rain. The dry particles that land on surfaces are also washed off by rain, increasing the acidity of runoff.

Natural gas use also is not much of a factor in smog formation. As opposed to petroleum products and coal, the combustion of natural gas results in relatively small production of smog-forming pollutants. The primary constituent of smog is ground-level ozone created by photochemical reactions in the near-surface atmosphere involving a combination of pollutants from many sources, including motor vehicle exhausts, volatile organic compounds such as paints and solvents, and smokestack emissions. The smog-forming pollutants literally cook in the air as they mix together and are acted on by heat and sunlight. The wind can blow smog-forming pollutants away

¹²Based on communications with personnel at the Gas Processors Association and the Columbia Gas Pipeline Company.

¹³Institute for Gas Technology test of trace constituents in two intrastate pipeline samples and two Canadian interstate samples supplied by the Pacific Gas and Electric Company.

¹⁴The aerosolized particulate matter resulting from combustion of fossil fuels is a mixture of solid particles and liquid droplets inclusive of soot, smoke, dust, ash, and condensing vapors.

¹⁵The larger particles are usually trapped in the upper respiratory tract, whereas those smaller than 10 microns can penetrate further into the respiratory system. The most infamous cases of extreme particulate matter pollution, in Donora, Pennsylvania, and in London, England, during the 1930s-1950s, killed thousands of people, and recent studies have indicated that a relatively small rise in 2.5-micron particulates causes a 5-percent rise in infant mortality and greater risk of heart disease. Michael Day, “Taken to Heart,” *New Scientist* (May 9, 1998), p. 23.

¹⁶Environmental Protection Agency, *National Air Pollution Trends Update, 1970-1997*, EPA-454/E-98-007 (December 1998), Table A-5 “Particulate Matter (PM-10) Emissions.”

from their sources while the reaction takes place, explaining why smog can be more severe miles away from the source of pollutants than at the source itself.

Greenhouse Gases and Climate Change

The Earth's surface temperature is maintained at a habitable level through the action of certain atmospheric gases known as "greenhouse gases" that help trap the Sun's heat close to the Earth's surface. The main greenhouse gases are water vapor, carbon dioxide, methane, nitrous oxide, and several engineered chemicals, such as chlorofluorocarbons. Most greenhouse gases occur naturally, but concentrations of carbon dioxide and other greenhouse gases in the Earth's atmosphere have been increasing since the Industrial Revolution with the increased combustion of fossil fuels and increased agricultural operations. Of late there has been concern that if this increase continues unabated, the ultimate result could be that more heat would be trapped, adversely affecting Earth's climate. Consequently, governments worldwide are attempting to find some mechanisms for reducing emissions or increasing absorption of greenhouse gases.¹⁷

On a carbon-equivalent basis, 99 percent of anthropogenically-sourced carbon dioxide emissions in the United States is due to the burning of fossil hydrocarbon fuels, with 22 percent of this attributed to natural gas (Table 1). Carbon dioxide emissions accounted for 83.8 percent of U.S. greenhouse gas emissions in 1997. Between 1996 and 1997, total estimated U.S. carbon dioxide emissions increased by 1.5 percent (22.0 million metric tons) to about 1,501 million metric tons of carbon, representing an increase of about 145 million metric tons, or almost 10.7 percent over the 1990 emission level. The increase between 1996 and 1997 was the sixth consecutive one. Increasing reliance on coal for electricity generation is one of the driving forces behind the growth in carbon emissions in 1996 and 1997.

The major constituent of natural gas, methane, also directly contributes to the greenhouse effect. Its ability to trap heat in the atmosphere is estimated to be 21 times greater than

that of carbon dioxide, so although methane emissions amount to only 0.5 percent of U.S. emissions of carbon dioxide, they account for about 10 percent of the greenhouse effect of U.S. emissions. In 1997, methane emissions from waste management operations (primarily landfills), at 10.4 million metric tons, and from agricultural operations, at 8.6 million metric tons, substantially exceeded those from the oil and gas industries combined, estimated to be 6.2 million metric tons.¹⁸

Water vapor is the most common greenhouse gas, at about 1 percent of the atmosphere by weight, followed by carbon dioxide at 0.04 percent and then methane, nitrous oxide, and manmade compounds such as the chlorofluorocarbons (CFCs). Each gas has a different residence time in the atmosphere, from about a decade for carbon dioxide to 120 years for nitrous oxide and up to 50,000 years for some of the CFCs. Water vapor is omnipresent and continually cycles into and out of the atmosphere. In estimating the effect of these greenhouse gases on climate, both the global warming potential (heat-trapping effectiveness relative to carbon dioxide) and the quantity of gas must be considered for each of the greenhouse gases.

Since human activity has minimal impact on the atmosphere's water vapor content, unlike the other greenhouse gases it is not addressed in the context of global warming prevention. The criteria pollutants specified in the CAA are reactive gases that, although they decay quickly, nevertheless promote reactions in the atmosphere yielding the greenhouse gas ozone. These gases indirectly affect global climate because they produce undesirable lower atmosphere ozone, as opposed to the desirable high-altitude ozone that shields Earth from most of the Sun's ultraviolet radiation. Carbon dioxide, on the other hand, directly contributes to the greenhouse effect; it presently represents 61 percent of the worldwide global warming potential of the atmosphere's greenhouse gases.

The United States is the largest producer of carbon dioxide among the countries of the world, both per capita (5.4 tons in 1996) and absolutely (Figure 23).¹⁹ The amount of carbon dioxide produced for an equivalent amount of heat production substantially varies among the fossil fuels, with

¹⁷In December 1997, representatives from more than 160 countries met in Kyoto, Japan, to establish limits on greenhouse gas emissions for participating developed nations. The resulting Kyoto Protocol established annual emission targets for countries relative to their 1990 emission levels. The target for the United States is 7 percent below 1990 levels.

¹⁸Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1997*, DOE/EIA-0573(97) (Washington, DC, October 1998), pp. 27 and 29.

¹⁹U.S. Department of Energy, Oak Ridge National Laboratory, G. Marland and T. Broden, "Ranking of the World's Countries by 1995 Total CO₂ Emissions from Fossil Fuel Burning, Cement Production, and Gas Flaring," <<http://cdiac.esd.ornl.gov/trends/emis/top95.tot>>.

Table 1. U.S. Carbon Dioxide Emissions from Energy and Industry, 1990-1997
(Million Metric Tons of Carbon)

Fuel Type or Process	1990	1991	1992	1993	1994	1995	1996	P1997
Natural Gas								
Consumption	273.2	278.1	286.3	296.6	301.5	319.1	319.7	319.1
Gas Flaring	2.5	2.8	2.8	3.7	3.8	4.7	4.5	4.3
CO ₂ in Natural Gas	3.6	3.7	3.9	4.1	4.3	4.2	4.5	4.6
Total	279.3	284.6	293.0	304.4	309.6	323.0	328.1	328.0
Other Energy								
Petroleum	591.4	576.9	587.6	588.8	601.3	597.4	620.6	627.5
Coal	481.5	475.7	478.1	494.4	495.6	500.2	520.9	533.0
Geothermal	0.1	0.1	0.1	0.1	*	*	*	*
Total	1,073.0	1,052.7	1,065.8	1,083.3	1,096.9	1,097.6	1,141.5	1,160.5
Other Sources								
Cement Production	8.9	8.7	8.8	9.3	9.8	9.9	9.9	10.1
Other Industrial	8.0	8.0	8.0	8.0	8.1	8.9	9.1	9.2
Adjustments ^a	-13.2	-13.2	-14.9	-11.3	-10.7	-11.2	-9.8	-7.1
Total	3.7	3.5	1.9	6.0	7.2	7.6	9.2	12.2
Total from Energy and Industry	1,355.9	1,340.8	1,360.6	1,393.6	1,413.8	1,428.1	1,478.8	1,500.8
Percent Natural Gas of Total	20.6	21.2	21.5	21.8	21.9	22.6	22.2	21.9

^aAccounts for different methodologies in calculating emissions for U.S. territories.

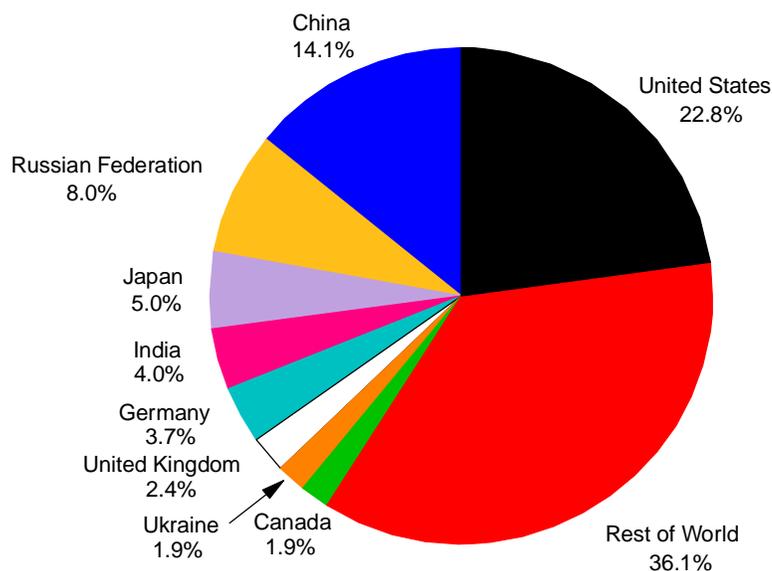
*Less than 0.05 million metric tons.

P = Preliminary data.

Notes: Emission coefficients are annualized for coal, motor gasoline, liquefied petroleum gases, jet fuel, and crude oil. Includes emissions from bunker fuels. Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1997* (October 1998).

Figure 23. Carbon Dioxide Emission Share by Country, 1995



Total 1995 emissions = 6,173 million metric tons of carbon

Note: Sum of percentages does not equal 100 because of independent rounding.

Source: U.S. Department of Energy, Oak Ridge National Laboratory, G. Marland, T. Broden, "Ranking of the World's Countries by 1995 Total CO₂ Emissions from Fossil Fuel Burning, Cement Production, and Gas Flaring," <<http://cdiac.esd.ornl.gov/trends/emis/top95.tot>>.

natural gas producing the least. For the major fossil fuels, the amounts of carbon dioxide produced for each billion Btu of heat energy extracted are: 208,000 pounds for coal, 164,000 pounds for petroleum products, and 117,000 pounds for natural gas (Table 2).

Effect of Greater Use of Natural Gas

Electric Power Generation

Projections of increased use of natural gas center principally on the increased use of natural gas in electric generation. For example, the *Annual Energy Outlook 1999* reference case projects natural gas consumption to rise by 10.3 trillion cubic feet (Tcf) from 1997 to 2020. Of this increase, 56 percent (5.8 Tcf) is expected to come as a result of increased use of natural gas for electricity generation. A recent Energy Information Administration (EIA) Service Report (prepared at the request of the House of Representatives Science Committee assuming no changes in domestic policy) analyzed the consequences of U.S. implementation of the Kyoto Protocol. In the carbon reduction cases cited in this report, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity*,²⁰ power plant use of natural gas (excluding industrial cogeneration) could increase to between 8 and 12 Tcf in 2010 and 12 to 15 Tcf in 2020. This growth is expected to develop as many of the new generating units brought on line are gas-fired. Some repowering of existing units may be undertaken as well.

Since electricity generation is the major source of U.S. sulfur dioxide (SO₂) and carbon dioxide (CO₂) emissions,²¹ as well as a major source of all other air pollutants excepting the chlorinated fluorocarbons, substitution of natural gas for other fossil fuels by utilities and nonutility

²⁰Energy Information Administration, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity*, SR/OIAF/98-03 (Washington, DC, October 1998), p. 76. This Service Report was requested by the U.S. House of Representatives Science Committee to provide information on the costs of the Kyoto Protocol without other changes in laws and regulations. The report relied on assumptions provided by the Committee.

²¹In 1996, electric utilities accounted for 12,604 thousand short tons of sulfur dioxide emissions out of a total of 19,113 thousand short tons (Environmental Protection Agency, *National Air Pollutant Emission Trends, 1990-1996*, EPA-454R-97-011 (December 1997), Table 2-1, p. 2-4); and for 532.4 million metric tons of carbon as carbon dioxide, exceeding the 482.9 and 473.1 million metric tons from the industrial and transportation sectors, respectively (Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1997*, DOE/EIA-0573(97) (October 1998), Table 7, p. 21).

generators would have a sizable impact on emission levels. However, if increased natural gas generation were to replace nuclear power or delay the commercialization of renewable-powered generation, this would represent a negative impact on emission levels.

In 1997, there were 10,454 electric utility generating units in the United States, with a total net summer generation capacity of 712 gigawatts.²² Of that capacity, 19 percent listed natural gas as the primary fuel and 27 percent listed it as either the primary or secondary fuel. But natural gas was actually used to generate only 9.1 percent of the electricity generated by electric utilities in 1997, down 1.2 percent from the 1995 value of 10.3 percent and one of the lowest proportions in the past 10 years. Coal was listed as the primary fuel source for almost 43 percent of the utility generating capacity and as a secondary source for only about 0.5 percent. But in 1997, it was the fuel used for 57.3 percent of net generation from electric utilities, up from 55.3 percent in 1995 and 56.3 percent in 1996.

A utility typically has a base-load generating capacity that is essentially continuously on line and capable of satisfying most or all of the minimum service-area load. The base-load capacity is supplemented by intermediate-load generation and peak-load generation capacities, which are used to meet the seasonal and short-term fluctuating demands above base load; reserve or standby units are also maintained to handle outages or emergencies. The majority of non-nuclear base-load units are coal-fired, yet many utilities have gas turbines, which are primarily used as peak-load generators.

Once the initial cost of a generating unit is paid for, fuel cost per unit of energy produced controls how electricity is generated. In 1997, the cost at steam-electric utility plants per million Btu for coal was less than half that for natural gas, \$1.27 versus \$2.76, and petroleum was even higher at \$2.88.²³ The per Btu natural gas cost to utilities increased by over one-third from 1995 to 1997, while the per Btu coal cost continued a 15-year decline, contributing to the decreased market share for natural gas. However, new technologies creating higher efficiency natural gas electric

²²Excludes nonutility generators. Energy Information Administration, *Inventory of Power Plants in the United States as of January 1, 1998*, DOE/EIA-0095(98) (Washington, DC, December 1998). Nonutility generators totaled 78 gigawatts of capacity in 1997, with 42 percent utilizing natural gas. Energy Information Administration, *Electric Power Annual 1997*, Vol. II, DOE/EIA-348(97) (Washington, DC, July 1998), Table 54.

²³Energy Information Administration, *Electric Power Annual 1997*, Vol. I, DOE/EIA-348(97) (Washington DC, July 1998), Table 20, p. 37.

Table 2. Pounds of Air Pollutants Produced per Billion Btu of Energy

Pollutant	Natural Gas	Oil	Coal
Carbon Dioxide	117,000	164,000	208,000
Carbon Monoxide	40	33	208
Nitrogen Oxides	92	448	457
Sulfur Dioxide	0.6	1,122	2,591
Particulates	7.0	84	2,744
Formaldehyde	0.750	0.220	0.221
Mercury	0.000	0.007	0.016

Notes: No post combustion removal of pollutants. Bituminous coal burned in a spreader stoker is compared with No. 6 fuel oil burned in an oil-fired utility boiler and natural gas burned in uncontrolled residential gas burners. Conversion factors are: bituminous coal at 12,027 Btu per pound and 1.64 percent sulfur content; and No. 6 fuel oil at 6.287 million Btu per barrel and 1.03 percent sulfur content—derived from Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants* (1996).

Source: Energy Information Administration (EIA), Office of Oil and Gas. **Carbon Monoxide:** derived from EIA, *Emissions of Greenhouse Gases in the United States 1997*, Table B1, p. 106. **Other Pollutants:** derived from Environmental Protection Agency, *Compilation of Air Pollutant Emission Factors*, Vol. 1 (1998).

generators can overcome the current price differential between the fuels.

The new power plants scheduled to come on line during the 10 years from 1998 through 2007 are 88 percent natural-gas-fired and only 5 percent coal-fired, but they will add only about 6 percent to total net generation capacity.²⁴ Thus, in order to make significant reductions in the volume of greenhouse gases and other pollutants produced by electricity generation, a significant amount of new unplanned gas-fired or renewable generation capacity would have to be built, or the existing generating equipment having natural gas as a fuel option would have to be utilized more and many of the existing coal plants would have to be repowered to burn gas.

The utilities have many supply-side options at their disposal to reduce or offset carbon dioxide emissions from power generation. These options include repowering of coal-based plants with natural gas, building new gas plants, extension of the life of existing nuclear plants, implementation of renewable electricity technologies, and improvement of the efficiency of existing generation, transmission, and distribution systems.

There are two principal conversion opportunities for utility power plants. The simplest and most capital-intensive approach is site repowering with an entirely new gas-turbine-based natural gas combined-cycle (NGCC) system. The more complex, less capital-intensive approach is steam

turbine repowering where a new gas turbine and a heat recovery steam generator are integrated with the existing steam turbine and auxiliary equipment. This option can have lower capital costs if site redesign costs are low, but entails a higher operating cost because it is less efficient than total state-of-the-art repowering.

As of January 1, 1998, there are 20 repowering projects planned in nine States that will primarily convert current oil-fired facilities to natural gas or co-firing capability; most of the projects are driven by economics with a secondary impetus as a response to the emission reduction requirements of the Clean Air Act Amendments of 1990 (see box, p. 59).

Complete conversion may not be a practical goal for a number of plants without expansion of the transportation pipeline network. Most of the candidate plants are located in primary gas-consuming regions served by major trunk lines. It appears that converted plants may have sufficient access to firm transportation capacity on these systems during the heating and nonheating seasons, during which between 16 and 24 percent of average national system capability is available for firm transportation, respectively.²⁵ The ability of a plant to use firm transportation capacity for gas supply will depend on the location and specific load characteristics of the pipelines serving that plant. However, because of recent regulatory reforms, electric generation plants may no longer be required to use firm transportation to serve their supply needs. Under Federal

²⁴Energy Information Administration, *Inventory of Power Plants in the United States as of January 1, 1998*, DOE/EIA-0095(98) (Washington, DC, December 1998), pp. 9 and 13.

²⁵Energy Information Administration, *Deliverability on the Interstate Natural Gas Pipeline System*, DOE/EIA-0618(98) (Washington, DC, May 1998), Table 14.

Clean Air Act Amendments of 1990: Emission Reduction Requirements for Utilities

The 1990 amendments to the Clean Air Act (CAA) require that electric utilities reduce their sulfur dioxide (SO₂) emissions by 10 million tons from the 1980 levels to attain an absolute cap of 8.9 million tons of SO₂ by 2000. Comparatively, SO₂ emissions from fossil-fueled electric generating units ranged from 15.0 million tons in 1993 to 11.6 million tons in 1995, with 12.2 million tons emitted in 1996. The same units also emitted 2,047.4 million tons of carbon dioxide (CO₂) in 1996, up from 1,967.7 million tons in 1995. Nonutility power producers added another 1.2 million tons of SO₂ and 556 million tons of CO₂ in 1995, the latest year for which data are available. Phase 1 of the CAA, 1995 through 1999, requires the largest polluters (110 named power plants) to reduce emissions beginning in 1995. The top 50 polluting plants produced 5,381 million tons of SO₂ emissions in 1996, 44 percent of the electric generation total. The second phase, effective January 1, 2000, will require approximately 2,000 plants to reduce their emissions to half the level of Phase I. The affected plants are required to install systems that continuously monitor emissions in order to track progress and assure compliance, and are allowed to trade emission allowances within their systems and with the other affected sources. Each source must have sufficient allowances to cover its annual emissions. If not, the source is subject to a \$2,000 per ton excess emissions fee and a requirement to offset the excess emissions in the following year. Bonus allowances can be earned for several reasons including early reductions in emissions and re-powering with a qualifying clean coal technology.

The CAA also requires the utilities to reduce their nitrogen oxide (NO_x) emissions by 2 million tons from the 1980 levels. In September 1998, the Environmental Protection Agency issued a new source performance standard for NO_x emissions from new (post-July 1997) electric utility and industrial/commercial/institutional steam generating units, including those that may become subject to such regulation via modification or reconstruction. The performance standard for new electric utility steam-generating units is 1.6 pounds per megawatthour of gross energy output regardless of fuel type, whereas that for modified/reconstructed units is 0.15 pounds per million Btu (MMBtu) of heat input. The standard for new industrial/commercial institutional steam generating units is 0.2 pounds per MMBtu of heat input, although for low heat-rate units firing natural gas or distillate oil the present limit of 0.1 pounds per MMBtu is retained. The switch from input-based to output-based accounting favors increased generating efficiency and the use of natural gas over distillate oil and especially coal, without the need to prescribe specific pollution control options.

electric restructuring, power plants may be able to use significantly more interruptible capacity or be able to use released capacity to satisfy their supply needs.

Nonutility generation (NUG) of electric power is a relatively recent and rapidly growing industry. The share of total electricity generated by NUGs has increased from 6.2 percent in 1989 to 11.5 percent in 1997.²⁶ Nonutilities are generally smaller than utilities and were encouraged by the passage of the Public Utility Regulatory Policies Act in 1978. Natural gas is the primary fossil fuel used in these applications, accounting for over 72 percent in 1997.

Transportation Sector

The second largest source of air pollution in the United States is the transportation sector, and in particular

gasoline- and diesel-powered motor vehicles. As the U.S. automobile industry first developed, experimentation with compressed natural gas (CNG) and other alternative fuels was conducted. But as petroleum products became increasingly plentiful, accessible, and inexpensive, these alternatives were largely pushed aside and U.S. transportation systems became petroleum-based. While few Americans have driven or owned a natural-gas-powered vehicle (NGV), people in other nations have been driving them since World War II when severe petroleum shortages curtailed gasoline availability. About 1,000,000 NGVs are presently in use worldwide, with Italy alone having more than 400,000 on the road. In contrast, fewer than 75,000 NGVs can be found on U.S. roads, not quite 0.04 percent of the more than 200 million U.S. vehicles. NGVs had a minuscule share of the U.S. vehicle fuel market in 1997, less than 1 billion cubic feet in a market equivalent to 30 trillion cubic feet.

²⁶Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(99/02) (Washington, DC, February 1999).

Interest in clean-burning alternative fuels has increased in recent years. After two oil embargoes, several oil price spikes, and the 1991 Gulf War, both petroleum prices and security of supply remain major concerns. The environmental problems associated with tailpipe emissions have also become a prime motivating factor. The Environmental Protection Agency estimated that motor vehicle tailpipe emissions are the source of more than half of all urban air pollution in the United States. These issues, along with the failure of many large U.S. metropolitan areas to meet the 1987 deadline for achievement of the National Ambient Air Quality Standards (primarily for ozone and carbon monoxide), have led to increased interest in alternative transportation fuels. There are a number of alternatives to gasoline, among which are electricity, methanol (produced from natural gas and butane), ethanol (produced from agricultural products), propane, liquefied natural gas, and compressed natural gas. In the future, these alternatives will compete with each other and with the "cleaner" reformulations of gasoline now being tested and other more flexible new technologies, such as hybrid gasoline-electric or diesel-electric vehicles. The relative success of these alternatives depends on numerous factors: automobile performance, ability to adapt the fuel distribution and marketing system, environmental impacts, safety, the economics of both fuel and vehicle, changes in technology, and public awareness and acceptance.

A number of legislative measures and regulatory initiatives have sought to ameliorate the automotive emissions problem. The Clean Air Act Amendments of 1990 mandate that in the 22 cities with 1988 populations of greater than 250,000, where ozone and/or carbon monoxide levels are most serious (nonattainment areas), owners of fleets of 10 or more vehicles must begin purchasing clean-burning

vehicles by model year 1998. In 1995 these urban areas, inclusive of their suburbs, were home to more than 85 million Americans (almost one-third of the U.S. population). They also have more than 30 percent of all registered vehicles.

Most observers agree that the primary competition in the evolving alternative fuels market is among three alternative carbon-based fuels (methanol, ethanol, and compressed natural gas (CNG)), electric vehicle technology, and reformulated gasoline (RFG). While liquefied petroleum gas (LPG or "propane") has essentially the same qualities as CNG with respect to emissions, range, safety, and fuel cost, and is widely used in U.S. rural agricultural areas, its supply probably could not meet broad expansion of demand. Less than 50 percent of LPG production is derived from natural gas; the majority of it is a byproduct of the oil refining process. Therefore, any significantly expanded use of LPG would require increased oil imports.

Widespread use of CNG as a transportation fuel would entail substantial new investment to expand the natural gas delivery infrastructure, largely involving massive addition of refueling stations at a cost of at least \$165,000 each. The CNG vehicles presently used in the United States, mostly fleet vehicles, are supported by fewer than 1,300 refueling stations as compared with more than 200,000 refueling stations serving gasoline and diesel powered vehicles. Fewer than 700 of the latter offer CNG to the general public, and then often by appointment only. EIA and other forecasters project limited growth in the use of CNG as an automotive fuel with most projections for 2010 consumption falling in the range of 250 to 440 billion cubic feet and less than 2.5 million vehicles (Table 3). It is quite likely that future NGV use will remain restricted to fleet vehicles.

Table 3. Forecasts of Natural Gas Consumption as a Vehicle Fuel

Source	In 2000		In 2010	
	Consumption (billion cubic feet)	Number of Vehicles (thousands)	Consumption (billion cubic feet)	Number of Vehicles (thousands)
Energy information Administration (EIA)	125	80	250	1,280
American Gas Association (AGA)	210	110	355	1,660
Gas Research Institute (GRI)	280	140	440	2,300

Sources: **Energy Information Administration:** *Annual Energy Outlook 1999*, Base Case Scenario (December 1998). **AGA:** American Gas Association, 1998 AGA-TERA Base Case (July 1998). **GRI:** Draft of GRI04 Baseline Projections (November 1998).

Air Conditioning Market

The primary opportunity for air pollution reduction in the space-conditioning market is use of natural gas in lieu of electricity for cooling. This would include gas-fired air conditioning for commercial, institutional, and industrial buildings and gas-fired heat pumps for residential and small commercial applications. In space-conditioning applications, natural gas competes with electricity and with energy conservation alternatives. Electricity currently dominates commercial and industrial cooling with a market share of more than 90 percent, while gas cooling's share is in the 3 to 7 percent range; consumption of gas for space cooling in 1997 was less than 100 billion cubic feet. This was not always the case. From the mid-1950s through the early 1970s, the gas cooling (often called gas absorption) equipment share of the large-tonnage cooling market ranged between 20 and 30 percent, with annual load additions ranging from 2 to over 4 billion cubic feet supplying 200 to 300 thousand tons of cooling. The load declined precipitously in the mid-1970s because of energy supply/price dislocations, regulatory restrictions on gas industry marketing, and consequent reductions in support activities by many manufacturers; shipments of large-tonnage absorption equipment declined to less than 50 thousand tons per year.

Gas absorption technology and market development continued in Japan, where gas serves more than half of the large-tonnage cooling market. The absorption share of chiller unit shipments in Japan continues to increase; in 1991 it accounted for over 90 percent of new units. Several Japanese companies have become major worldwide suppliers of absorption equipment, and gas-cooling research and development (R&D) expenditures by the Japanese government and manufacturers continue to grow. In the United States, R&D conducted by the natural gas industry, the Gas Research Institute, and gas equipment manufacturers has led to commercialization of a variety of new gas engine-drive, absorption, and desiccant technologies. In addition, equipment and technologies from the major Japanese companies are being imported or licensed by U.S. firms. Over the past 2 to 3 years, all of the major U.S. chiller manufacturers have substantially increased their activity in gas cooling.

Despite the increased interest in using natural gas for space cooling, electric cooling equipment is strongly established (with more than 90 percent of the market) and well supported by substantial R&D funding and strong marketing. However, with the Federal government phasing out the use of chlorofluorocarbons (CFCs or chlorine-based

refrigerants) used in electric cooling systems, natural gas absorption systems, which operate free of CFCs, and engine-driven and other natural-gas-based systems, which typically operate on non-CFC refrigerants, should gain some additional advantage.²⁷

Environmental Impacts of Gas Production and Delivery

The extraction and production of natural gas, as well as other natural gas operations, do have environmental consequences (Figure 24) and are subject to numerous Federal and State laws and regulations (see box, p. 63). In some areas, development is completely prohibited so as to protect natural habitats and wetlands. At present, oil and gas drilling is prohibited along the entire U.S. East Coast, the west coast of Florida, and the U.S. West Coast except for the area off the coast of southern California. Drilling is also generally prohibited in national parks, monuments, and designated wilderness areas.

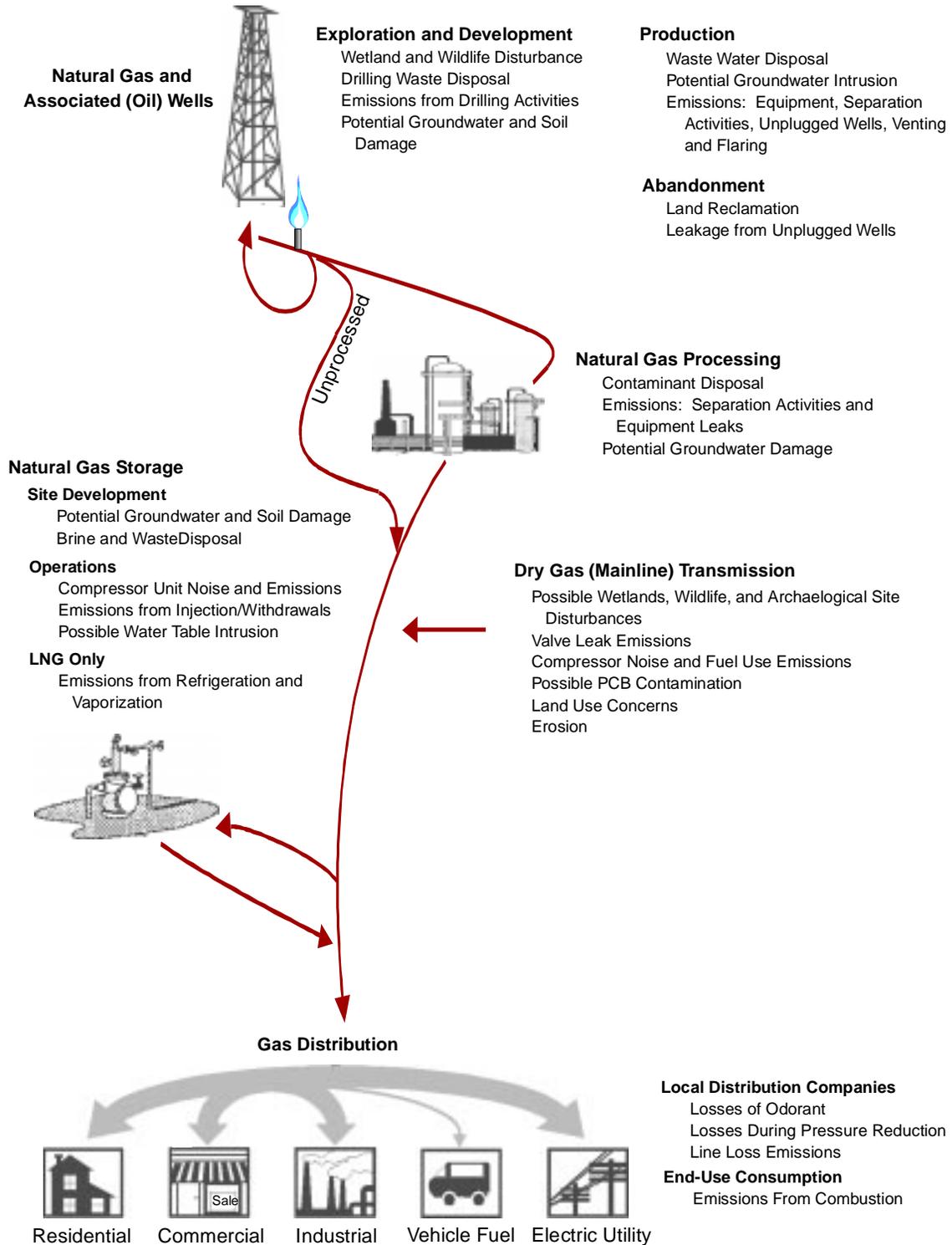
Natural Gas Exploration and Production

The environmental side-effects of natural gas production start in what is called the upstream portion of the natural gas industry, beginning with selection of a geologically promising area for possible future natural gas production. An upstream firm will collect all available existing information on the geology and natural gas potential of the proposed area and may decide to conduct new geologic and geophysical studies. It will usually need to acquire permission to enter the area by obtaining permits for Federal, State, or local government land or by leasing right of access on private lands. If the road network is dense enough, some area studies may only require access along public right-of-way.

The most common new study is a seismic survey. Onshore seismic surveys are done using either a small explosive charge as the acoustic source or special vibrator trucks that literally shake the ground. In water, the source is either a small explosive charge or an air or gas gun. The primary environmental disturbances involved with land operations are the laying of cable and geophones. Sometimes this

²⁷American Gas Association, Gas Industry Online: Gas Technology Summer '97, "New Directions in Natural Gas Cooling," <<http://www.aga.com/events/gtsu97/directions.html>>.

Figure 24. Environmental Impacts of Natural Gas Production, Transmission, and Distribution



LNG = Liquefied natural gas. PCB = Polychlorinated biphenyl.
 Source: Energy Information Administration, Office of Oil and Gas.

Environmental Laws Affecting Natural Gas Operations

Date	Legislation	Effect on Natural Gas Operations
1966	National Historic Preservation Act	Major construction projects must avoid damaging or destroying designated National Historic Landmarks.
1969	National Environmental Policy Act	Requires a detailed environmental review before any major or controversial Federal action, such as approval of an interstate pipeline or interstate gas storage facility.
1970 Amended 1977 and 1990	Clean Air Act	Regulates air emissions from area, stationary, and mobile sources. Affects operations of gas plants and is expected to cover glycol dehydrator operations.
1970	Occupational Safety and Health Act	Governs worker exposure to toxic chemicals, excessive noise levels, mechanical dangers, heat or cold stress, or unsanitary conditions.
1973	Endangered Species Act	Nesting areas of endangered species must not be disturbed by construction or operations. Drilling mud pits if used may have to be screened to prevent endangered species from landing in them by mistake. Pipelines and gas storage sites should avoid endangered species areas.
1974 Amended 1986	Safe Drinking Water Act	Regulates underground injection wells and directs the protection of sole source aquifers.
1976	Toxic Substance Control Act	Gives the Environmental Protection Agency authority to require testing of chemical substances, both new and old, and to regulate them where necessary. Limits or prohibits the use of certain substances.
1976 Amended 1984	Resource Conservation and Recovery Act	Encourages the conservation of natural resources through resource recovery. Defines hazardous waste as waste which may cause an increase in mortality or poses a substantial hazard to human health or the environment when improperly disposed. A waste is: (a) hazardous if it is ignitable at less than 140 degrees F; (b) reactive if it reacts violently with water, is normally unstable, generates toxic gases when exposed to water or corrosive materials or is capable of detonation when exposed to heat or flame; and, (c) corrosive if it has a pH \leq to 2 or \geq to 12.5 and toxic if it meets or exceeds a certain concentration of pesticides/herbicides, heavy metals or organics.
1977	Clean Water Act	Regulates discharges of pollutants to U.S. waters. Wetlands are protected under this act. Permits are required, conditioned to force either avoidance or mitigation banking. Affects construction of pipelines and facilities in wetlands and dredging for drilling barge movement in coastal wetlands. Provides for delegation of many permitting, enforcement, and administrative aspects of the law to the States.
1980 Amended 1986	Comprehensive Environmental Response, Compensation, and Liability Act. Superfund Amendments and Reauthorization Act.	Acts on hazardous waste activities that occurred in the past. Material does not have to be a "waste." Covers all environmental media: air, surface water, ground water and soil.
1982	Federal Oil and Gas Royalty Management Act	Among other requirements, oil and gas facilities must be built in a way that protects the environment and conserves Federal resources.
1986	Emergency Planning and Community Right-to-Know Act	Facilities (gas plants and compressor stations) must report on the hazardous chemicals they use and store, providing information on a chemical's physical properties and health effects, and a listing of chemicals that are present in excess of certain amounts.
1990	Oil Pollution Act	Offshore drilling requires posting of significant pollution bonds.
1990	Pollution Prevention Act	Prevents pollution through reduction or recycling of source material. Requires facility owners or operators to include toxic chemical source reduction and recycling report for any toxic chemical.
1992	Energy Policy Act	Encourages development of clean-fuel vehicles; encourages energy conservation and integrated resource planning.

requires the cutting of roads or trails and, when explosives are used, the drilling of a small, short hole to encase them. Explosives are rarely used in water anymore since they can stun or kill marine life in the immediate vicinity; the now commonly used gas or air gun source was developed to ameliorate these effects, as well as increase personnel safety.

Following analysis of the geologic and geophysical data, the firm may proceed to acquire the right to drill and produce natural gas from owners of the land and relevant government permitting authorities. In making leasing and permitting decisions involving Federal lands, the potential environmental impacts of future development are often considered. Such considerations include the projected numbers and extent of wells and related facilities, such as pipelines, compressor stations, water disposal facilities, as well as roads and power lines.

Disposal of Drilling Waste

The drilling of a gas well involves preparing the well site by constructing a road to it if necessary, clearing the site, and flooring it with wood or gravel. The soil under the road and the site may be so compacted by the heavy equipment used in drilling as to require compaction relief for subsequent farming. In wetland areas, such as coastal Louisiana, drilling is often done using a barge-mounted rig that is floated to the site after a temporary slot is cut through the levee bordering the nearest navigable stream. However, the primary environmental concern directly associated with drilling is not the surface site but the disposal of drilling waste (spent drilling muds and rock cuttings, etc.). Early industry practice was to dump spent drilling fluid and rock cuttings into pits dug alongside the well and just plow them over after drilling was completed, or dump them directly into the ocean if offshore. Today, however, the authority issuing the drilling permits, in coordination with the EPA, determines whether the operator may discharge drilling fluids and solids to the environment or whether they must be shipped to a special disposal facility. Drilling of a typical gas well (6,000 feet deep) results in the production of about 150,000 pounds of rock cuttings and at least 470 barrels of spent mud.²⁸

At onshore and coastal sites, drilling wastes usually cannot be discharged to surface waters and are primarily disposed of by operators on their lease sites. If the drilling fluids are saltwater- or oil-based, they can cause damage to soils and

groundwater and on-site disposal is often not permitted, so operators must dispose of such wastes at an off-site disposal facility. The disposal methods used by commercial disposal companies include underground injection, burial in pits or landfills, land spreading, evaporation, incineration, and reuse/recycling. In areas with subsurface salt formations, such as Texas, Louisiana, and New Mexico, disposal in man-made salt caverns is an emerging, cost-competitive option. Such disposal poses very low risks to plant and animal life because the formations where the caverns are constructed are very stable and are located beneath any subsurface fresh water supplies. Water-based drilling wastes have been shown to have minimal impacts on aquatic life, so offshore operators are allowed to discharge them into the sea. They are prohibited from so discharging oil-based drilling wastes, and these are generally hauled to shore for disposal.

In recent years, new drilling technologies such as slimhole drilling, horizontal drilling, multilateral drilling, coiled tubing drilling, and improved drill bits, have helped to reduce the generated quantity of drilling wastes. Another advanced drilling technology that provides pollution-prevention benefits is the use of synthetic drilling fluids which combine the superior drilling performance of oil-based fluids with the more favorable environmental impacts of water-based drilling fluids. Their use results in a much cleaner well bore and less sidewall collapse, such that the cuttings volume is reduced.

Emissions

Exploration, development, and production activities emit small volumes of air pollutants, mostly from the engines used to power drilling rigs and various support and construction vehicles. An indication of the level of air emissions from these operations is available from wells in the Federal Offshore off California (Table 4). As the number of wells increases, such as in the Gulf of Mexico, so do the emissions for exploratory drilling and development drilling, while emissions from supporting activities rise less directly. Offshore development entails some activities not found elsewhere (i.e., platform construction and marine support vessels), but the environmental effects from onshore activities, which include drilling pad and access road construction, especially for development drilling, are many times larger because of the much higher level of activity.

²⁸Assumes a 20-inch diameter hole to 200 feet followed by an 8-inch (average) hole diameter for the next 5,800 feet, plus a mud pit volume of 35 barrels.

Table 4. Typical Annual Air Pollutant Emissions from Exploration, Development, and Production Activities Offshore California

Activity	Type of Air Pollutant Emission (short tons per year)				
	Volatile Organic Compounds	Nitrogen Oxides	Sulfur Dioxide	Carbon Monoxide	Total Suspended Particulates
Exploratory Drilling - Assumes four 10,000-foot wells drilled at 90 days per well; includes emissions from support vessels on site and in transit.	28.0	175.6	14.0	34.0	14.5
Platform Installation - Includes emissions from support vessels.	8.5	192.0	13.0	34.4	10.7
Pipeline Installation - Includes emissions from support vessels.	1.8	31.6	2.1	6.1	2.0
Development Drilling - Assumes eight 10,000-foot wells drilled per year; includes emissions from support vessels.	7.9	106.2	4.6	40.4	5.1
Offshore Platform - Assumes annual production of 4.38 million barrels of oil and 5,840 million cubic feet of natural gas.	25.7	99.0	0.7	69.3	5.5
Support Vessels - Assumes one crew boat trip and one supply boat every 2 days; includes emissions in transit for 50-mile round trip.	0.9	42.4	2.9	6.4	1.9
Onshore Gas Processing - Assumes processing of 21,900 million cubic feet of natural gas annually.	13.6	39.8	21.0	4.8	3.5

Notes: The number of exploratory and development wells drilled annually in the Gulf of Mexico Offshore and onshore in the United States is much larger than in the California Offshore. Total U.S. exploratory wells numbered 3,024 in 1997 while developmental wells numbered 23,453 (Energy Information Administration, *Monthly Energy Review*, Table 5.2). Offshore operations in the Gulf of Mexico include emissions from helicopter crew support flights as well as crew and supply boats. Onshore drilling includes emissions during construction of drilling pads and access roads.

Sources: **Nitrogen Oxides:** Radian, "Assessment of No_x Control Measures for Diesel Engines on Offshore Exploratory Vessels and Rigs - Final Report" presented to Joint Industries Board (1982). **Other Emissions:** Form and Substance, Inc. for Minerals Management Service, *A Handbook for Estimating the Potential Air Quality Impacts Associated with Oil and Gas Development Off California* (October 1983).

Disposal of Produced Water

Coproduction of a variable amount of water with the gas is unavoidable at most locations. Because the water is usually salty, its raw disposal or unintentional spillage on land normally interferes with plant growth. Since the produced water represents the largest volume waste stream generated by exploration and production activities, its disposal is a

significant problem for the industry. The disposal process varies depending on whether the well is onshore or offshore, the local requirements, and the composition of the produced fluids. Most onshore-produced water is disposed of by pumping it back into the subsurface through on-site injection wells. In some parts of the United States, injection is not practical or economically viable and the produced water is therefore piped or trucked to an off-site treatment

facility. The disposal methods used by commercial disposal companies include injection, evaporation, and treatment followed by surface discharge. For example, the water produced from onshore coal bed methane wells in Alabama is disposed of by land application or by discharge into streams after treatment; because of the elevated levels of total dissolved solids, the water is tested by biomonitoring for acute toxicity.²⁹

Offshore, during a typical year of operations in the Gulf of Mexico, it is estimated that approximately 685,000 barrels of produced water are discharged, about half of which is piped to onshore locations where it is treated and subsequently discharged to onshore waters.³⁰ Studies have found few impacts of produced water disposal in the deeper waters of the Gulf of Mexico or off Southern California. In very shallow coastal areas (2 to 3 meters deep), more extensive impacts from long-term discharges are suggested.³¹ One of the original environmental concerns regarding oil and gas drilling and production involves undesirable movement of fluids along the well bore from deeper, often salty, formations to formations near the surface that contain fresh water. Operators are generally required to cement casing from the wellhead through all rock layers containing fresh water. While oil will obviously contaminate fresh groundwater, entry of natural gas into fresh water zones used for human or agricultural supply will not, but it can create an explosion or suffocation risk.

Downhole separators are a new technology that promises to reduce the environmental risk from produced water as well as reduce industry's cost of handling it. These devices separate oil and gas from produced water within the well bore, such that most of the produced water can be safely injected into a subsurface formation without ever being brought to the surface.

²⁹K.R. Drotter, D.R. Mount, and S.J. Patti, "Biomonitoring of Coalbed Methane Produced Water from the Cedar Cove Degasification Field, Alabama," in Proceedings of the 1989 Coalbed Methane Symposium, The University of Alabama (April 17-20, 1989), p. 363.

³⁰U.S. Department of Interior, National Oceanic and Atmospheric Administration, Gianessi and Arnold, "The Discharge of Water Pollutants from Oil and Gas Explorations and Production Activities in the GOM Region" (April 1982), as cited in "Oil and Gas Program: Cumulative Effects," U.S. Department of the Interior, Minerals Management Service, *Outer Continental Shelf Report*, MMS 88-0005 (1988), p. V-19.

³¹J.G. Mackin, "A Study of the Effect of Oilfield Brine Effluents on Benthic Communities in Texas Estuaries" (College Station, TX, Texas A&M Research Foundation, 1971), Proj. 735, p. 72, cited by Minerals Management Service in "Oil and Gas Program: Cumulative Effects," *Outer Continental Shelf Report* (1988).

Condensate Production Hazards

There are an estimated 13,000 condensate tank batteries which separate, upgrade, store, and transfer condensate streams from natural gas produced in the United States and its offshore areas.³² The separation is done using glycol dehydration units, which the EPA has identified as a potential source of hazardous air pollutants (as well as tanks and vessels storing volatile oils, condensate, and similar hydrocarbon liquids). The EPA has published a Notice of Proposed Rulemaking seeking to reduce these emissions by 57 percent for oil and natural gas production facilities and by 36 percent from glycol dehydration units in natural gas transmission and storage facilities. The final rule is not expected until May 1999.

Venting, Flaring, and Fugitive Emissions

It is sometimes necessary either to vent produced gas into the atmosphere or to flare (burn) it. Worldwide, most venting and flaring occurs when the cost of transporting and marketing gas co-produced from crude oil reservoirs exceeds the netback price received for the gas. This practice is by no means as common in the United States as it was a few decades ago when oil was the primary valuable product and there was no market for much of the co-produced natural gas until the interstate pipeline system was developed after World War II. The minor venting and flaring that does occur now is regulated by the States and may happen at several locations: the well gas separator, the lease tank battery gas separator, or a downstream natural gas plant.

The total amount of methane vented in 1996, 1.14 million metric tons, was the second largest component of methane emissions from natural gas operations (Table 5). Throughout the entire process of producing, refining, and distributing natural gas there are losses or fugitive emissions. Production operations account for about 30 percent of the fugitive emissions, while transmission, storage, and distribution account for about 53 percent. All systems of pipes that transmit any fluid are subject to leaks. In the case of natural gas, any leak will escape to the atmosphere. The total methane emissions from all natural gas operations in 1996 was 6.66 million metric tons, or 22 percent of all U.S. anthropogenic methane emissions. When weighted by the global warming potential of

³²Environmental Protection Agency, Federal Register Notice, Part II, 40 CFR Part 63, *National Emissions Standards for Hazardous Air Pollutants: Oil and Natural Gas Production and Natural Gas Transmission and Storage; Proposed Rule* (February 6, 1998), p. 6292.

Table 5. U.S. Methane Emissions by Source, 1989-1996
(Million Metric Tons of Methane)

Source	1989	1990	1991	1992	1993	1994	1995	1996
Natural Gas Operations								
Natural Gas Wellhead Production	0.28	0.29	0.30	0.30	0.30	0.31	0.30	0.32
Gathering Pipelines	1.08	1.07	1.03	1.03	0.92	0.84	0.74	0.74
Gas-Processing Plants	0.55	0.62	0.69	0.68	0.70	0.70	0.72	0.72
Heaters, Separators, etc.	0.17	0.17	0.17	0.17	0.18	0.19	0.19	0.19
Total Production	2.08	2.15	2.19	2.18	2.10	2.04	1.96	1.97
Gas Venting	0.77	0.75	0.81	0.83	0.97	1.01	0.68	1.14
Gas Transmission and Distribution	3.51	3.56	3.60	3.64	3.57	3.56	3.55	3.55
Total Natural Gas Operations	6.36	6.46	6.60	6.65	6.64	6.61	6.19	6.66
Natural Gas Stationary End-Use Combustion								
Residential	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005
Commercial	0.004	0.003	0.004	0.004	0.004	0.004	0.004	0.004
Industrial	0.012	0.013	0.013	0.013	0.014	0.014	0.015	0.015
Electric Utility	*	*	*	*	*	*	*	*
Total Natural Gas Combustion	0.021	0.021	0.022	0.022	0.023	0.023	0.024	0.024
Total from Natural Gas	6.381	6.481	6.622	6.672	6.663	6.633	6.214	6.684
Percent of U.S. Methane Emissions	20%	21%	21%	21%	22%	21%	20%	20%
Other Energy Sources								
Coal Mining	4.31	4.63	4.38	4.28	3.50	3.90	3.98	3.93
Oil Well Production	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Oil Refining and Transportation	0.08	0.08	0.08	0.08	0.08	0.09	0.09	0.09
Non-Natural-Gas Stationary Combustion	0.80	0.50	0.53	0.55	0.48	0.47	0.52	0.52
Mobile Sources	0.29	0.27	0.26	0.26	0.25	0.24	0.25	0.25
Total Other Energy	5.52	5.55	5.29	5.21	4.35	4.74	4.88	4.83
Non-Energy Sources								
Waste Management	11.04	11.11	11.00	10.89	10.83	10.73	10.60	10.44
Agricultural Sources	8.18	8.29	8.55	8.77	8.79	9.11	9.05	8.75
Other Industrial Processes	0.12	0.12	0.11	0.12	0.12	0.13	0.13	0.13
Total Non-Energy	19.34	19.52	19.66	19.78	19.74	19.97	19.78	19.32
Total U.S. Methane Emissions	31.29	31.59	31.63	31.74	30.82	31.38	30.93	30.90

*Less than 500 metric tons of methane.

Notes: Data for 1997 from Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 1997* (October 1998) were not used because the report groups gas operations in a less detailed format. The report states that U.S. methane emissions totaled 29.11 million metric tons in 1997, with natural gas systems accounting for 6.03 million metric tons, or 21 percent. Totals may not equal sum of components because of independent rounding.

Source: EIA, *Emissions of Greenhouse Gases in the United States 1996* (October 1997).

methane, this amounts to 2 percent of total U.S. greenhouse gas emissions in 1996.

Removal of Carbon Dioxide

Almost 500 billion cubic feet of the 24.2 trillion cubic feet of gross withdrawals of natural gas in the United States in 1997 was in fact carbon dioxide (Table 6). The carbon dioxide content of natural gas has been increasing over recent years. This is mostly attributable to the growth of production in fields with a relatively high carbon dioxide component, such as in the Midwest, the Green River Basin

in Wyoming, and the San Juan Basin and Piceance Basin coal bed gas fields, as a result of increased natural gas demand in recent years. Since 1990, the volume of carbon dioxide coproduced with natural gas has risen by 23.4 percent.

More carbon dioxide (CO₂) is produced with nonassociated natural gas than with associated-dissolved natural gas primarily because about 85 percent of U.S. gas production is from nonassociated gas wells. Also, the chemical processes involved in the formation of natural gas lead to a higher CO₂ content in nonassociated gas. In 1997, the

Table 6. U.S. Carbon Dioxide Inherent in Domestic Natural Gas Production, 1990-1997
(Billion Cubic Feet, Unless Otherwise Noted)

Carbon Dioxide	1990	1991	1992	1993	1994	1995	1996	P1997
Produced								
With Nonassociated Gas	362.8	371.9	386.6	406.5	422.5	415.1	441.2	451.7
With Associated-Dissolved Gas	14.7	15.0	15.8	15.8	14.8	14.2	13.8	14.1
Total	377.6	386.9	402.4	422.3	437.3	429.3	455.0	465.8
Emitted								
Production Activities	248.8	256.7	271.1	286.8	300.2	293.8	312.9	321.3
Pipeline Consumption	5.4	4.9	4.8	5.1	5.6	5.7	5.8	5.8
End-Use Consumption	123.4	125.4	126.4	130.5	131.5	129.8	136.3	138.7
Total¹	377.6	386.9	402.4	422.3	437.3	429.3	455.0	465.8
Total (Million Metric Tons of Carbon)²	5.4	5.6	5.8	6.1	6.3	6.2	6.5	6.7

P = Preliminary data.

¹Includes small amount carbon dioxide reinjected in Texas and Wyoming that is ultimately retained in the reservoir.

²Energy Information Administration, *Emissions of Greenhouse Gases in the United States, 1997* (October 1998), p. 119.

Note: Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Office of Oil and Gas estimates, unless otherwise noted.

CO₂ component of nonassociated gas produced was 2.5 percent as compared with 0.2 percent for associated-dissolved natural gas.

The CO₂ content of produced natural gas has numerous possible dispositions. For example, it can be left in the natural gas that is returned to reservoirs to repressurize them, thereby increasing the oil recovery factor, or it can be left in the natural gas used for fuel in well, field, and lease operations, or vented, etc. When processing of the raw natural gas stream is economically warranted, the CO₂ is typically extracted by amine scrubbing and then vented to the atmosphere. The remaining carbon dioxide left in the finished natural gas stream becomes a fugitive emission somewhere during transmission, distribution or consumption.

Of the 500 billion cubic feet of carbon dioxide produced along with U.S. natural gas (Table 1), most is emitted to the atmosphere. Almost 69 percent of carbon dioxide emissions occur during gas production, with the remainder in transmission, distribution, and consumption. The largest single point of emissions is at natural gas plants, where at least 200 billion cubic feet is emitted.³³

Ancillary Production Activities

Gas exploration and production also result in a number of other, relatively minor environmental consequences. For example, gas production and processing operations

sometimes accumulate naturally occurring radioactive materials (NORM). Over a 20-year period, the Environmental Protection Agency estimates that the combined production of natural gas and crude oil in the United States resulted in accumulation of 13 million metric tons of NORM, as opposed to 1.7 billion tons in coal ash and more than 21 billion metric tons associated with metal, uranium, and phosphate mining and processing.³⁴ NORM can accumulate as scale or sludge in natural gas well casing, production tubing, surface equipment, gas gathering pipelines, and by-product waste streams.³⁵ NORM concentrations vary from background levels to levels exceeding those of some uranium mill tailings.³⁶ Traditionally, these materials have been regulated by the States.

Proper precautions must be taken during disposal of contaminated casing and pipes to ensure that they are not converted into such things as furniture or playground

³⁴Environmental Protection Agency, "Disposal of Naturally Occurring and Accelerator-Produced Radioactive Materials," EPA 402-K-94-001 (August 1994), <<http://www.epa.gov/radiation/radwaste/radwaste/narm.htm>>.

³⁵The sources of most of the radioactivity are isotopes of uranium-238 and thorium-232 which are naturally present in the subsurface formations from which natural gas is produced. The primary radionuclides of concern are radium-226 in the uranium-238 decay series and radium-228 in the thorium-232 decay series. Other radionuclides of concern include those resulting from the decay of radon-226 and radon-228, such as radon-222. Pipe scale and sludge accumulations are dominated by radium-226 and radium-228, while deposits on the interior surfaces of gas plant equipment are predominantly lead-210 and polonium-210.

³⁶Stephen A. Marinello and Mel B. Hebert, "Minimizing NORM Generation Most Cost-Effective Approach," *The American Oil & Gas Reporter* (December 1995), p. 101.

³³Energy Information Administration, Office of Oil and Gas analysis (September 1998).

equipment. The production waste streams most likely to be contaminated by elevated radium concentrations include produced water, scale, and sludge. Spillage or intentional release of these waste streams to the ground can result in NORM-contaminated soils that must also be disposed of. Most produced water containing NORM is disposed of on-site through injection wells for onshore locations and is discharged into the sea at offshore locations. Other types of NORM waste are presently disposed of at gas and oil production sites and at off-site commercial disposal facilities, mostly by underground injection. Smaller quantities of NORM are disposed of through burial in landfills, encapsulation inside the casing of plugged and abandoned wells, or land spreading.

The physical appearance of a drilling rig or a wellhead is offensive to some people. In the oil-productive urban portions of onshore California, drilling rigs and wellheads are routinely hidden inside mock buildings in part for this reason and in part to muffle the noise of operations. Unfortunately an offshore platform cannot be hidden in the same way. Aside from this “viewshed” issue, an offshore rig precludes commercial fishing operations on an average of 500 acres because of it and its anchors’ presence.³⁷ Offshore noise and light pollution are also a concern because noise can carry for long distances over and underwater and offshore rigs and platforms operate round-the-clock and are very well-lit at night.

When drilling is conducted in remote areas on land, the roads and airfields constructed by the well operators can later provide easier public access for other purposes such as hunting, fishing, and other outdoor activities unless special provisions are made to prevent it. Access is generally a bigger problem relative to oil wells since the transportation cost per unit of value for natural gas is higher than that for crude oil, which makes natural gas development in remote areas less likely.

Natural Gas Processing

The processing of natural gas poses low environmental risk, primarily because natural gas has a simple and comparatively pure composition. There are 697 natural gas processing facilities in the United States.³⁸ Their purpose is

³⁷U.S. Department of the Interior, Minerals Management Service, “Oil and Gas Program: Cumulative Effects,” *Outer Continental Shelf Report*, MMS 88-0005 (1988).

³⁸Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1997 Annual Report*, DOE/EIA-0216(97) (Washington, DC, December 1998).

to remove the heavier hydrocarbons such as ethane, propane, pentanes, and hexanes, as well as contaminants such as carbon dioxide and water, in order to bring the natural gas stream into conformity with pipeline Btu content and other specifications. Typical processes performed by a gas plant are separation of the heavier-than-methane hydrocarbons as liquefied petroleum gases, stabilization of condensate by removal of lighter hydrocarbons from the condensate stream, gas sweetening, and consequent sulfur production and dehydration sufficient to avoid formation of methane hydrates in the downstream pipeline.³⁹ The EPA-identified hazardous air pollutant (HAP) emission points at natural gas processing plants are the glycol dehydration unit reboiler vent, storage tanks,⁴⁰ and equipment leaks from components handling hydrocarbon streams that contain HAP constituents. Other potential HAP emission points are the tail gas streams from amine-treating processes and sulfur recovery units.

Methods vary for removing natural gas contaminants, such as hydrogen sulfide gas, carbon dioxide gas, nitrogen, and water. Commonly the hydrogen sulfide is converted to solid sulfur for sale. Likewise the carbons and nitrogen are separated for sale to the extent economically possible but otherwise the gases are vented, while the water is treated before release. Compressor operation at gas plants has a similar impact to that of compressors installed at other locations.

Pipeline Construction and Expansion

Gas gathering pipeline systems move natural gas from the well to a gas plant or transmission pipeline. The diameter of the gathering pipe depends on the number and deliverability of the wells served. Construction involves clearing and grading right-of-way (ROW), trenching, pipe welding and coating, pipe burial, and restoration of the disturbed surface (although gathering pipelines are sometimes laid on the ground surface). Operation of the system involves supporting compressor stations and, in the case of water-producing wells, water collection, pumping, pipelining, and disposal according to State or local regulations. In near-offshore areas such as the Mississippi River Delta, canals have to be dredged to permit movement of barge-mounted oil and gas drilling rigs and the laying of oil and gas gathering pipelines.

³⁹H.D. Beggs, *Gas Production Operations* (Tulsa, OK: OGCI Publications, November 1995), pp. 219-222.

⁴⁰Particularly those that handle volatile oil and condensates, which may be significant contributors to overall hazardous air pollutant emissions because of flash emissions.

The environmental impacts of transmission pipeline construction and operation are considered by the Federal Energy Regulatory Commission prior to approval of construction. About 300,000 miles of high-pressure transmission pipelines are in place in the United States and its offshore areas. The construction ROW on land is commonly 75 to 100 feet wide along the length of the pipeline; this is the area disturbed by clearing and grading, trenching, soil storage, pipe storage, vehicle movement, pipe burial, trench in-filling, and surface restoration, which is between 9.1 and 12.1 acres per mile of pipe. In agricultural areas, it may take 1 to 3 years for cropland to return to its former productivity after pipeline installation. The permanent ROW on land is typically 50 to 75 feet wide times the length of the pipeline. This is the area needed by the operator for routine inspection and maintenance operations, occupying from 6.1 acres to 9.1 acres per mile of pipe.⁴¹ For every mile of offshore pipeline constructed on non-rocky sea floors, about 6 acres of sea bottom are disturbed and 2,300 to 6,000 cubic yards of sediment displaced.⁴²

Pipeline Operations

Valves are installed along the pipeline to allow isolation of leaking or failed segments of the line or complete shutdown should that become necessary. The pipe is generally brought to the surface so that the valve can be easily reached and observed; siting is commonly in areas accessible by road but away from residential areas. The EPA has identified leaking valves as a potential hazardous air pollutant emission point. It has also identified pipeline “pigging” operations and the storage of resulting wastes as potential hazardous air pollutant emission points. Pigging operations are performed to inspect and clean the interior of pipelines and entail safe disposal of the removed solid and liquid contaminants.

Compressor stations (about 1,900 of them in the United States)⁴³ are also located along the route of the pipeline to ensure efficient movement of the gas. Because the location of a compressor station need not be precise, it can usually be sited so as to reduce its impact on the human or natural environment. However, there are unavoidable emissions of

⁴¹Federal Energy Regulatory Commission, *Pony Express Pipeline Project Environmental Assessment*, Docket No. CP96-477-000 (April 1997), p. 2-20.

⁴²Minerals Management Service, “Oil and Gas Program: Cumulative Effects,” MMS 88-0005 (1988), pp. V-23 and V-20.

⁴³Environmental Protection Agency, Federal Register Notice, Part II, 40 CFR Part 63, *National Emissions Standards for Hazardous Air Pollutants: Oil and Natural Gas Production and Natural Gas Transmission and Storage; Proposed Rule* (February 6, 1998), p. 6292.

nitrogen oxides (NO_x) and other gases during compressor operations. A transmission compressor station powered by natural gas has been estimated to produce 1.50 grams of NO_x per baseplate horsepower per hour (g/bhp-hr), 2.30 g/bhp-hr of carbon monoxide, and 1.50 g/bhp-hr of volatile organic compounds.⁴⁴ Methane leakage also occurs (Table 5). Significant reductions in methane leakage have occurred by converting wet (oil) shaft seals to dry (high-pressure gas) shaft seals, which reduces the leakage rate range from 40 to 200 standard cubic feet (scf) per minute to at most 6 scf per minute.⁴⁵

Some transmission pipelines used polychlorinated biphenyls (PCBs) as lubricants in their compressors prior to 1976 when their manufacture was banned by the Toxic Substance Control Act. The PCBs are a group of aromatic organic compounds that have inherent thermal and chemical stability but are quite toxic. Unfortunately, they diffused out of the compressors into the pipelines of those systems that utilized them; their cleanup has been a significant problem. Research is continuing into methods for removal of the PCBs.

Underground Storage Operations

The construction and operations associated with underground natural gas storage also have environmental impacts. There are about 410 underground gas storage facilities in the United States, which have been variously developed in former oil or natural gas producing reservoirs, in aquifers,⁴⁶ and in man-made cavities in salt deposits.

Storage well drilling has a similar impact to that of drilling production wells with the exception that the geology is often better known and the drilling is therefore less risky. In developing storage facilities at an aquifer or abandoned oil or gas reservoir, horizontal wells have recently been utilized to increase the input/output capacity and minimize total drilling. If a salt deposit is being developed for storage, the salt water disposal can be into adjacent underground reservoirs or into the surface water

⁴⁴Federal Energy Regulatory Commission, *Pony Express Pipeline Project Environmental Assessment*, Docket No. CP96-477-000, p. 3-33.

⁴⁵Environmental Protection Agency, “Lessons Learned from Natural Gas STAR Partners, Replacing Wet Seals with Dry Seals in Centrifugal Compressors,” Executive Summary, <<http://www.epa.gov/gasstar/sealsprn.htm>>.

⁴⁶A body of rock that is sufficiently permeable to conduct ground water and to yield economically significant quantities of water to wells and springs, although they do not do the latter in the vicinity of a storage site. Robert L. Bates and Julia A. Jackson, American Geological Institute, *Dictionary of Geological Terms*, 3rd ed. (New York: Doubleday, 1983), p. 26.

environment under permitted conditions. The laying of storage field pipelines has a similar effect as that of gas gathering pipelines, but usually occurs in a much smaller area and away from populated areas and sensitive habitats. The establishment of underground storage facilities at depleted production field sites sometimes entails little in the way of additional disturbance.

The environmental impacts associated with storage compressor facilities are similar to those for gathering and mainline compressor installations. Dehydration units located in storage fields are noted by EPA as a potential source of hazardous air pollutants. It is common practice to “blow” down production wells (often annually) when a storage reservoir is developed in an aquifer or an abandoned oil or gas reservoir. This practice clears loose particles from the interstices of the storage reservoir rock adjacent to the well bore, thereby restoring the rock’s permeability and the maximum flow rate. However, this practice produces a noise effect and the need to flare the rapidly delivered gas.

Natural Gas Distribution

The local natural gas distribution company (LDC) takes gas from the intra- or interstate pipeline company serving its area. Facilities operated by the LDC include pressure reduction facilities, odorant storage and insertion facilities, and the small-diameter local distribution pipeline network with its attendant valves and meters. Line losses are more apparent in the LDCs’ pipelines than elsewhere, as the odorant has been added and leaks can be detected by the human nose. Line losses are also more dangerous in distribution networks since built-up areas have many enclosed spaces, and their infusion with leaked gas can produce an explosive mixture of natural gas and air

ignitable by any flame, spark, or electrostatic discharge that comes in contact with it. Nevertheless, the local distribution of coal or fuel oil for commercial or residential use is significantly less energy efficient, and in the case of oil potentially more environmentally hazardous than is that of natural gas.

Outlook

According to EIA’s *Annual Energy Outlook 1999* reference case, natural gas consumption for electricity generation nearly triples, from 3.3 trillion cubic feet (Tcf) in 1997 to 9.2 Tcf, by 2020. Gas-fired generation is the economical choice for construction of new power generation units through 2010, when capital, operating, and fuel costs are considered.⁴⁷ Natural gas consumption and emissions are projected to increase more rapidly than other fossil fuels, at average annual rates of 1.7 percent through 2020.⁴⁸ However, this represents reductions in total carbon emissions derived from the environmental advantages of natural gas.

Concern about global warming and further deterioration of the environment caused by escalating industrial expansion and other development is being addressed by worldwide initiatives (e.g., the Kyoto Protocol) that seek a decrease in emissions of greenhouse gases and other pollutants. Natural gas is expected to play a key role in strategies to lower carbon emissions, because it allows fuel users to consume the same Btu level while less carbon is emitted. If carbon-reduction measures are implemented, EIA projects in its Kyoto Protocol analysis that, by 2010, natural gas demand would increase by 2 to 12 percent over otherwise expected levels.⁴⁹ Emissions from natural gas consumption would also rise, but the natural gas share of total emissions would increase only slightly.

⁴⁷Energy Information Administration, *Annual Energy Outlook 1999*, DOE/EIA-0383(99) (Washington, DC, December 1998), p. 82.

⁴⁸Energy Information Administration, *Annual Energy Outlook 1999*, p. 85.

⁴⁹Energy Information Administration, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity*, SR/OIAF/98-03 (Washington, DC, October 1998), pp. xix and 95.