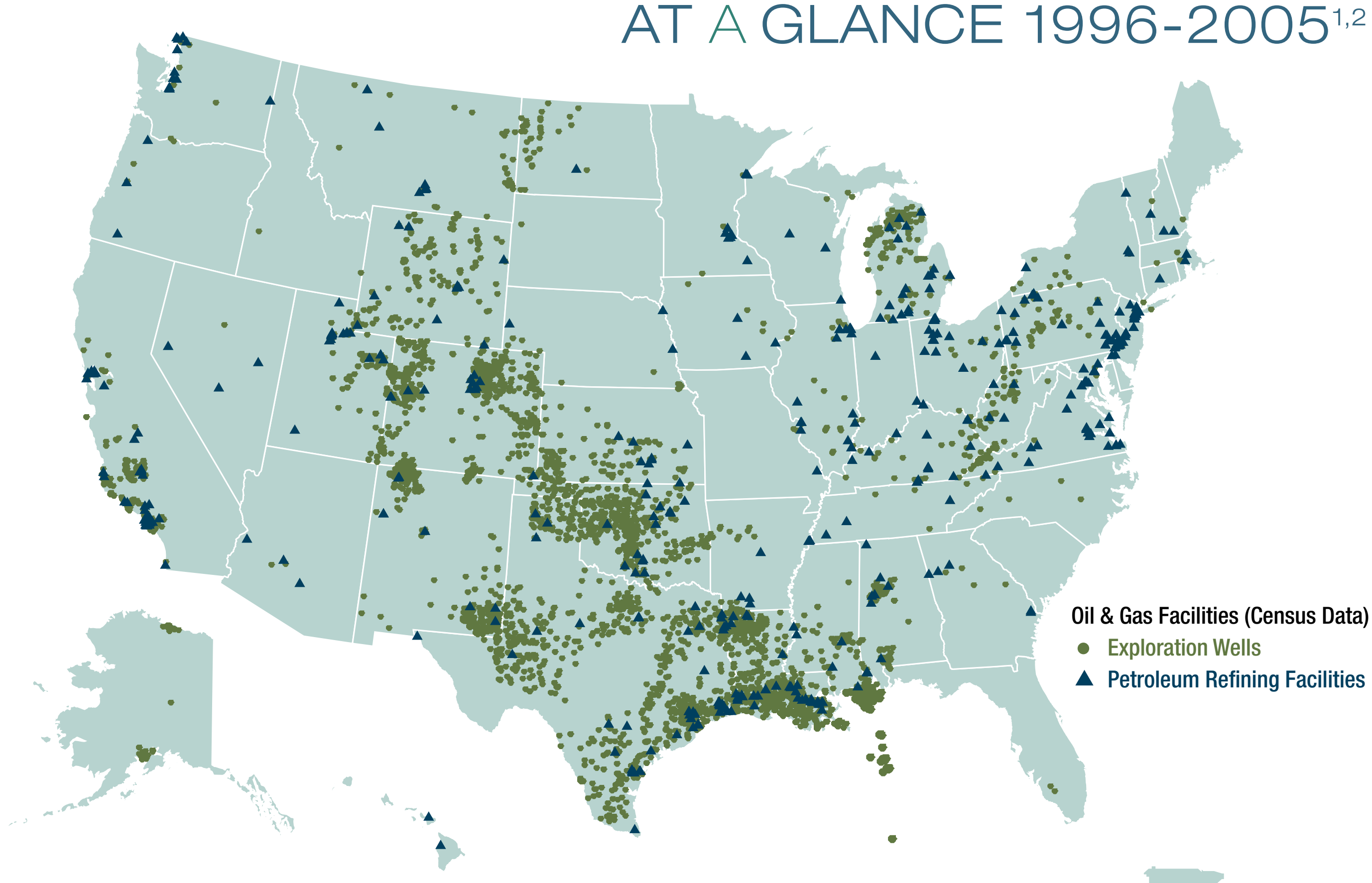
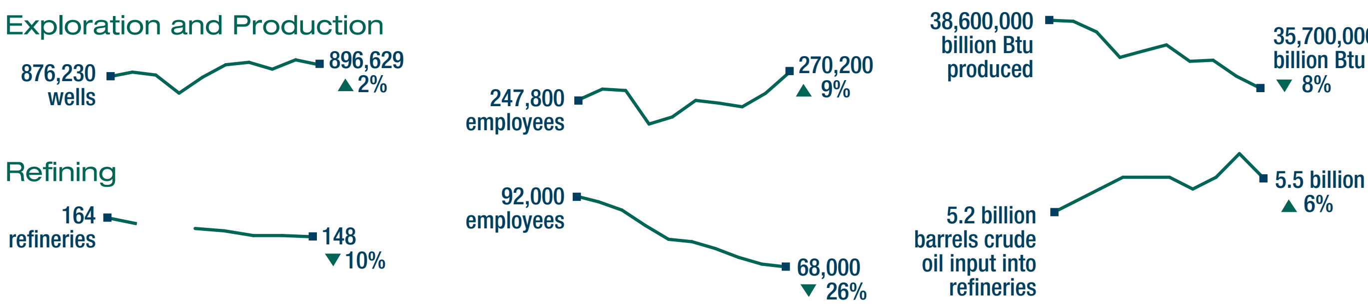
OIL & GAS

AT A GLANCE 1996-2005[1,2]





Profile

The Oil & Gas sector includes the following operations, which are subject to a number of federal and state regulations:

- Exploration and Drilling: Onshore and offshore geophysical operations, including seismic studies, engineering, well testing, drilling operations, and transportation of personnel or equipment to and from sites.
- Oil and Gas Production: Operation, maintenance, and servicing of production properties on- and offshore, including transportation to and from sites.
- Petroleum Refining: Distillation, hydrotreating, alkylation, reforming, and other distinct processes for converting crude oil into petroleum products.[3]

In 2005 the Oil & Gas sector included 498,454 oil wells and 398,161 gas wells in operation. The sector employed 1,381 rotary rigs for drilling new wells.[4] The United States is the world's third-largest petroleum producer and second-largest natural gas producer.[5]

Petroleum products derived from crude oil through the refining process include gasoline (motor fuel), distillate (diesel fuel, home heating oil), kerosene (jet fuel), petroleum coke, residual fuel oil (industrial and marine use), petroleum gases (liquified petroleum gas, ethane, butane), elemental sulfur, asphalt and road oils, petrochemical plant feedstocks, and lubricating oils.

The environmental impacts of the sector's activities vary significantly. This chapter is divided into two sections, discussing the environmental implications of exploration and production (E&P), followed by a discussion of petroleum refining.

Exploration and Production[6]

E&P operations locate and extract crude oil and natural gas from geologic formations. Geologic and regional differences, as well as basin-specific approaches to extract the resources available, influence the environmental footprint associated with E&P operations. This section overviews the major processes and factors affecting that footprint.

Exploration and Drilling

Exploration for oil and gas involves geologic testing of prospective formations. These activities often involve construction of new roads in remote areas and air emissions caused by vehicular traffic to, from, and within potential drilling locations. Drilling is done with truck-mounted rigs powered by diesel engines, which also affect air quality. Operators prepare a pad for drilling equipment including creation of pits and ponds to contain various fluids and mud used in drilling and to manage the drill cuttings (rock displaced while drilling the well). Operators also install tanks or pipes to gather the resources produced.

Oil Production

The classifications of light, medium, heavy, or extra-heavy refer to the crude oil's gravity as measured on the American Petroleum Institute (API) scale, and reflect the energy required and environmental impacts inherent in producing and refining the oil. Light crude oil, for example, flows naturally or can be pumped relatively easily to the wellhead. Conversely, heavy crude oil does not flow easily and has higher viscosity than light or medium crudes, requiring enhanced oil recovery (EOR) processes such as heating or diluting.

When crude oil, associated natural gas, and formation water arrive at the wellhead, operators must separate them before further processing and transport. The water is generally high in saline content and may contain hydrocarbons. Separator units near the wellhead separate the oil from the associated natural gas. The natural gas is processed to recover natural gas liquids (mostly propane and butane). Impurities such as carbon dioxide (CO_2) and hydrogen sulfide (H_2S) also are removed from the gas before it is transported. If pipeline access is not available, the gas may be used on location to power production equipment or may be re-injected into the oil reservoir to maintain reservoir pressure.

Water produced with oil must be removed because it is corrosive and an impediment to transportation and storage. Water is separated at gathering stations and oil storage tanks in the field.

Measurable quantities of oil remain in the reservoir once primary production processes have concluded, and additional resources can be recovered through EOR processes. Such processes supplement natural reservoir forces to improve flow rate and recovery. Representative EOR techniques include water flooding, gas injection, and chemical and thermal processes—all of which can have environmental impacts.

Natural Gas Production

Production of gas generally begins as natural flow from the wellhead into the gathering system. As a field matures, reservoir pressure begins to decline and gas compression equipment helps recover the gas. In cases where "pipeline-quality" natural gas is produced at the wellhead, producers move the product directly to the pipeline grid. In most cases, raw gas streams must be treated prior to introduction into the pipeline system.

Water and heavier hydrocarbons are removed at the wellhead, and may result in water discharges and waste disposal issues. Light hydrocarbons are removed at a natural gas processing plant and sold for other uses. In addition, some natural gas production yields "dry gas" with no associated crude oil, condensate, or liquid hydrocarbons. Gas also may contain non-hydrocarbons such as CO_2, H_2S, and nitrogen. If present in sufficient concentrations, these constituents also are removed at natural gas processing plants.

As natural gas supplies from the nation's historic production regions are depleted, the industry's focus has shifted. For example, the Rocky Mountain region contains prospective production areas that are expected to make major contributions to U.S. natural gas reserves. In addition, shale gas production is becoming a key component of U.S. supplies; the Barnett Shale in northern Texas is one of the largest onshore natural gas fields in the country.

Unconventional Oil and Gas Resources and Emerging Technologies

Unconventional oil and gas resources are defined loosely as resources that are deeper or more difficult to recover than those that have been recovered historically. Given the mature state of the domestic petroleum industry and current access limitations (e.g., prohibitions or restrictions on developing offshore and onshore sites within sensitive ecosystems), oil and gas resources from conventional formations within the United States have been largely depleted. Unconventional resources require advanced recovery techniques and may require that extracted material be upgraded to meet relevant fuel specifications. For example, oil shale must be heated to release petroleum-like liquids that can be turned into fuel. Unconventional gas resources usually require more wells (closer well spacing) to recover the gas resource than in recovery of gas from conventional gas resources. Common practice for unconventional gas production can require 8 to 16 times as many wells per area of land as for historical conventional gas recovery. The impact of this greater well density is mitigated by the use of advanced drilling techniques, which allow multiple wells to be drilled from one well pad. To be viable, unconventional resource recovery methods must also address a wide range of socioeconomic and environmental issues. The following are representative of unconventional resources and emerging technologies.

Tight Gas and Coal Bed Methane (CBM)

Tight gas refers to natural gas found in less permeable and porous formations, such as limestone or sandstone. For recovery, the gas-bearing formation must be broken up, or "fractured," to allow gas to flow to the well. This requires many more wells than conventional recovery. CBM refers to natural gas trapped in underground coal seams, which can be extracted before mining the coal. CBM production often requires removing large amounts of water from underground coal seams before the methane (CH_4) in the seams can be released and recovered as an energy source.

Directional and Horizontal Drilling

New methods to reduce the cost and environmental impacts of recovering unconventional resources include directional and horizontal drilling techniques. Directional drilling includes all forms of drilling where the hole is slanted or curved from the drilling site to reach the target reservoir. Directional drilling commonly is used offshore as evolving techniques enable producers to reach oil reserves in extremely sensitive ecosystems while most of the drilling equipment is miles away. In onshore operations, directional drilling greatly reduces the amount of surface disturbance by enabling producers to use a small surface well pad and to drill outward to access larger portions of the target reservoir.

Horizontal drilling enables the wellbore to be shifted from a vertical to a horizontal orientation. By using horizontal drilling techniques, operators can drill many wellbores from a single location, thus reducing the above-ground footprint. Horizontal drilling is used extensively in accessing unconventional natural gas resources; however, due to the lower porosity of the underlying formations, more wells must be drilled (e.g., tighter well spacing) to extract the gas.

Advanced drilling rigs may also be designed to slide on rails to the next destination within a production area, reducing environmental disturbances and improving efficiency.

Energy Use

E&P operations need energy to power oil and gas recovery. Requirements range from prospecting for new wells, to moving trucks and equipment onsite and off, to drilling and pumping the wells. Development drilling can involve numerous wells, and the power used to operate and transport drilling rigs increases the energy intensity of E&P operations. To increase pressure and enhance recovery rates from largely depleted reservoirs, most onshore oil production operations use pumps powered by electricity or natural gas.

The energy required for E&P increases as the resource recovered becomes more difficult to access and produce. For example, approximately two-thirds of U.S. gas wells are now drilled into unconventional formations. While sometimes shallower than conventional wells, unconventional gas wells typically require more energy than conventional wells for well stimulation operations. In the case of CBM and some shale gas operations, energy use for producing, managing, and treating large volumes of produced water is significant.[7]

Air Emissions

Air emissions from E&P operations include criteria air pollutants (CAPs), hazardous air pollutants (HAPs), and greenhouse gases (GHGs). E&P air emissions are generated by combustion in stationary and mobile internal combustion engines, gas processing equipment, and other activities. In addition, E&P operations produce air emissions through venting and flaring. Fugitive emissions of methane are also significant.

Oil and natural gas production is included as an area source category for regulation under EPA's Urban Air Toxics Strategy, is subject to New Source Performance Standards for new or modified stationary sources, and is subject to state and federal operating permit requirements to limit air pollution. E&P operations are not included within the scope of industries that report to EPA's Toxics Release Inventory (TRI), and too few facilities are currently included in the National Emissions Inventory (NEI) to be representative of the sector.

Criteria Air Pollutants

EPA has, however, analyzed the sector's air emissions in Region 8 (Colorado, Montana, North Dakota, South Dakota, Utah, and Wyoming) using state emissions inventory data developed by the Western Regional Air Partnership (WRAP).[8] A draft study prepared by EPA's Sector Strategies Program characterized regional air emissions and non-air pollution from produced water and drilling wastes. Region 8, which includes the Rocky Mountains (Rockies), has experienced tremendous growth in natural gas production activities in the last decade and the trend is likely to increase. Table 1 shows 2002 CAP emissions from oil and gas exploration and production reported by WRAP in Region 8.

TABLE 1

CAP and VOC Emissions in Region 8 2002

Pollutant	Estimated Emissions in Tons
VOCs	262,953
NO_X	87,130
CO	37,880
SO_2	18,385
PM	834

Source: U.S. Environmental Protection Agency

Greenhouse Gases

Major GHG emissions from E&P operations include CO_2 and CH_4. Acid-gas removal units that remove CO_2 from natural gas are the primary source of GHGs from natural gas processing plants. Indirect sources of CH_4 are venting and fugitive emissions. A substantial portion of field production CH_4 emissions come from pneumatic devices such as liquid level controllers, pressure regulators, and valve controllers. Other sources of CH_4 emissions are dehydrators and gas engines.

Table 2 shows estimated GHG emissions from Region 8 for 2002. When CH_4 emissions are weighted by their global warming potential (21 times that of CO_2), CO_2-equivalent methane emissions represent the sector's largest non-CAP emissions, at more than 10 million tons. Although those emissions are not regulated, anticipated GHG regulations affect current and planned E&P activities.

TABLE 2

GHG Emissions in Region 8 2002

Pollutant	Estimated Emissions in Tons
CH_4	10,366,442 (CO_2-equivalent)
CO_2	5,191,897

Note:
Estimated emissions of CH_4 were 493,640 tons.

Source: U.S. Environmental Protection Agency

Water Use and Discharges

E&P operations entail various water uses and discharges, with related environmental implications. EPA data systems contain limited information on discharges to waterways, as most operations are regulated under general permits and report to state, rather than federal, agencies.[9]

Producers use water to assist in resource extraction, from enhanced oil recovery to hydraulic fracturing. Oil and gas operations must also manage "produced water"—water that either occurs naturally in the formation and must be disposed of or reused after extraction, or water that is injected to stimulate production.

Reducing Emissions and Saving Money

In 2005 the Devon Energy Corporation, WY, prevented the release of nearly 6.0 billion cubic feet (Bcf) of CH_4, equivalent in terms of GHG emissions to 2.6 million tons of CO_2. By implementing emissions reduction techniques in concert with various process improvements, Devon retained significant volumes of product (e.g., methane gas in the pipeline) and realized an economic benefit of more than $43 million. Devon received EPA's 2005 Natural Gas STAR Production Partner of the Year award.[10]

The most widely used EOR technique involves injecting water into the reservoir (e.g., "water flooding"). Water, injected under pressure, pushes the oil toward the recovery or producing well. The recovered fluids (water and oil) are separated; oil is sent on to distribution, and water is either treated and reused or disposed in permitted underground injection control wells. Injection wells are permitted through state oil and gas regulatory agencies that place limits on injection volume and pressure. Water flooding represents a major source of produced water managed by producers.

Hydraulic fracturing is the most commonly used method of gas well stimulation. It involves pumping a water-based solution into the formation at pressures up to 10,000 pounds per square inch, which induces fractures in the formation. A material such as silica sand also is pumped in to prop the fractures open, enabling the gas to flow more freely to the wellbore. Fracturing generally is accomplished with large truck-mounted pumps powered by diesel engines. Today, tight sand fracturing in the Rockies typically involves stimulation of many zones in a well with spacing intervals of up to thousands of feet. In shale formations such as the Barnett Shale, several separate fractures are carried out within the horizontal portion of the well.

In 2004, EPA completed its assessment of the potential for contamination of underground sources of drinking water by reviewing existing literature on water quality incidents that potentially were linked to hydraulic fracturing. EPA concluded there were no confirmed cases of drinking water contamination from fracturing fluid injection into CBM wells or from subsequent underground movement of fracturing fluids.

Chemical compositions, and environmental impacts, of produced water vary significantly depending on the geologic characteristics of the reservoir producing the water and the separation and treatment technologies used.[11]

Table 3 shows the amount of produced water from oil and gas extraction activities in Region 8 by state for 2002.[12] Almost 3 billion barrels of produced water were discharged in Region 8, almost 75% of which was in Wyoming.

TABLE 3

Produced Water by State 2002

State	Barrels
Colorado	348,255,005
Montana	123,397,156
North Dakota	98,537,154
South Dakota	8,108,174
Utah	136,296,362
Wyoming	2,091,105,179
Total	2,805,699,030

Source: U.S. Environmental Protection Agency

Oil wells generally discharge more produced water than gas wells. The category "oil with gas wells" (where "associated gas" is also produced) constituted the largest contributor of produced water in Region 8, as shown in Table 4. Oil-only wells released the second largest amount of produced water. Combined, these two well types account for 69% of total produced water in the region. Wyoming is the primary source of produced water in the region for both well types.

In managing produced water, E&P operators use a variety of technologies and techniques. A common approach involves using gravity to separate water from the recovered oil in storage tanks at a production site. The produced water then is stored in separate tanks prior to disposal or beneficial reuse. In some instances, produced water is injected back into formations to be used in enhanced oil and gas recovery.[13] The potential for reusing the water, and relevant environmental impacts, largely depends on the salinity and chlorine content of the water, as well as contaminant concentrations. For example, produced water can contain a mixture of inorganic and organic compounds, and, in many cases, residual chemical additives that are added into the hydrocarbon production process.[14]

TABLE 4

Produced Water by Well Type 2002 (Barrels)

State	Oil-Only Wells	Gas-Only Wells	Oil with Gas Wells	Gas with Oil Wells	Total
Colorado	81,962,976	158,856,545	102,323,995	5,111,489	348,255,005
Montana	50,775,321	16,847,685	55,708,537	65,613	123,397,156
North Dakota	20,953,673	3,521	74,617,442	2,962,518	98,537,154
South Dakota	915,122	614	5,121,998	2,070,440	8,108,174
Utah	21,684,832	31,145,993	79,283,960	4,181,577	136,296,362
Wyoming	601,234,810	569,061,152	853,631,461	67,177,756	2,091,105,179
Total	777,526,734	775,915,510	1,170,687,393	81,569,393	2,805,699,030

Source: U.S. Environmental Protection Agency

These water quality characteristics determine whether the water can be discharged into local rivers and streams or used for irrigation, or must be treated or specially disposed of. Treatment can include evaporation ponds or processing the water to reduce its salinity. This complex issue includes the volume of water being produced, the rate of flow of the streams (e.g., ephemeral or perennial), and the compositional characteristics of the water.

EPA regulates discharges associated with offshore oil and gas activities on the outer continental shelf under the National Pollutant Discharge Elimination System (NPDES) program. Issued permits include Clean Water Act requirements, as well as EPA's guidelines for determining the degradation of marine waters. In addition, new source discharges are subject to provisions of the National Environmental Policy Act.

Waste Generation and Management

After produced water, nonhazardous solid wastes are the second-largest category of wastes resulting from E&P operations. These wastes contain mud, rock fragments, and cuttings from the wellbore, as well as chemicals added to improve drilling-fluid properties. Drilling fluids are used to control downhole pressure, lubricate the drill bit, condition the drilled formations, provide hydraulic pressure to aid drilling, and remove cuttings from the wellbore. Drilling fluid is pumped down the drill pipe and circulated back to the surface where the rock cuttings are removed and the drilling fluid is recirculated.

Devon Increasing Its Water Conservation Efforts

Devon Energy Corporation, WY, is deploying mobile recycling technology to reclaim wastewater produced from gas well completions in the Barnett Shale field. Recycling units treat up to three-quarters of a million gallons of water per day, removing hydrocarbons, dissolved salts, and other impurities, and allowing reuse of 85% of the water. Devon uses freshwater produced from coal bed natural gas wells to create lakes and ponds suitable for wildlife and livestock. Devon received the Wyoming Game and Fish Department's Coal Bed Methane Natural Resource Stewardship Award in 2002 and the Department's Industry Reclamation and Wildlife Stewardship Award in 2004.[15]

Table 5 shows estimated amounts of drilling wastes in Region 8 in 2002.[16] Oil and gas companies can minimize drilling wastes and their environmental impacts through recycling and reuse of certain drilling byproducts, the use of nontoxic drilling fluids, and the employment of a closed-loop drilling fluid system to manage fluid wastes. Potential groundwater contamination from drilling fluids and the amount of area used for disposal of such wastes are also important impacts.

The industry uses water-based and oil-based drilling fluids. Drilling fluids typically are stored at the well site in lined reserve pits or closed-loop systems, depending upon geologic and hydrologic conditions and state requirements. Used drilling fluids typically are disposed of in injection wells or are reformulated and reused. Cuttings typically are collected and stored in lined pits and may be buried onsite (after dewatering), landfilled, or used in agricultural applications depending upon geologic and hydrologic conditions and individual state requirements. Treated drill cuttings have been used beneficially as fill material; daily cover material at landfills; and aggregate or filler in concrete, brick, or block manufacturing. Construction applications for drill cuttings include use in road pavements, asphalt, and in manufacturing cement.

TABLE 5

Estimated Drilling Wastes 2002

State	Barrels
Colorado	6,138,174
Montana	2,741,195
North Dakota	1,484,341
South Dakota	37,451
Utah	4,533,724
Wyoming	10,834,600
Total	25,769,484

Source: U.S. Environmental Protection Agency

Other E&P wastes include:

- **Oily soil:** Soil contaminated with oil, usually resulting from equipment leaks and spills.
- **Tank bottoms:** Heavy hydrocarbons, sand, clay, and mineral scale that deposit in the bottom of oil and gas separators, treating vessels, and crude oil stock tanks.
- **Workover fluids:** Produced from well control, drilling, or milling operations, and stimulation or cleanup of an oil and gas-bearing formation.
- **Produced sand:** Sand and other formation solids built up in the wellbore in both producing and injection wells.
- **Pit and sump waste:** Heavy materials settled on the bottom of pits or sumps used to store production fluids. These materials must be removed.
- **Pigging waste:** Produced when pipelines are cleaned or "pigged." The waste consists of produced water, condensed water, trace amounts of crude oil, and natural gas liquids. It may contain small amounts of solids such as paraffin, mineral scale, sand, and clay.
- **Normally occurring radioactive material:** Occurs where extraction causes a concentration of naturally occurring radiation beyond normal background levels.

Petroleum Refining

Latest Environmental Statistics for Refining[17]

Energy Use: 3.1 quadrillion Btu

Emissions of Criteria Air Pollutants: 832,000 tons

Releases of Chemicals Reported to TRI: 66.1 million lbs.

Air Emissions: 42.2 million lbs.

Water Discharges: 17.7 million lbs.

Waste Disposals: 6.3 million lbs.

Recycling, Energy Recovery, or Treatment: 1 billion lbs.

Hazardous Waste Generated: 5.1 million tons

Hazardous Waste Managed: 5.1 million tons

The data discussed in this report are drawn from multiple public and private sources. See the Data Guide *and the* Data Sources, Methodologies, and Considerations *chapter for important information and qualifications about how data are generated, synthesized, and presented.*

Energy Use

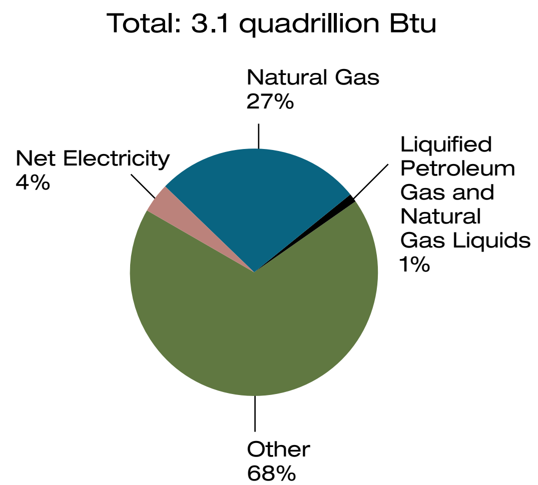
Petroleum refining operations consumed 3.1 quadrillion Btu in 2002.[18] The most energy-intensive processes include distillation, hydrotreating, alkylation, and reforming.[19] After removing salt content from the crude oil feedstock, refiners use atmospheric or vacuum distillation to separate components with varying boiling points. They then restructure the hydrocarbon molecules. Processes such as hydrotreating remove various constituents (e.g., sulfur, nitrogen, and heavy metals) to produce cleaner burning products. Finally, refiners blend the previously distilled fractions of oil into finished products.

Various factors influence the energy required to refine petroleum, including individual product specifications. For example, certain markets require particular blends, or "boutique" fuels. Under the Clean Air Act (CAA), State Implementation Plans may specify using cleaner burning fuels in select locations. Producing those custom fuels generally requires significant energy inputs into the refining process. In addition, national requirements such as those in ultra-low sulfur diesel fuel standards require significant amounts of energy to reduce the sulfur content within the crude feedstock.

Higher sulfur crude oil is increasingly a primary feedstock for refiners, and that trend is likely to increase in the coming decade and beyond, given the relative availability and affordability of these inputs. In response, U.S. refiners have invested in technology to remove sulfur more efficiently. These investments will also enable refiners to meet tightening fuel specification standards to improve air quality.[20]

FIGURE 1

Fuel Use for Energy 2002



Notes:
1. Other is primar ly from refinery gases, generation from renewables and net steam (the sum of purchases, generation from renewables, and net transfers).
2. Net electricity is an estimation of purchased power and power generation onsite.

Source: U.S. Department of Energy

Refinery fuel gas (also called still gas), catalyst coke, and natural gas are the primary fossil fuels consumed by refiners, as shown in Figure 1.[21] Refinery fuel gases, represented by "other" in the figure, result from various petroleum refinery processes such as crude oil distillation, cracking, reforming, and treating. These gases are collected and processed to recover propane or other light hydrocarbons. Refiners then remove sulfur and nitrogen compounds. This cleaner gas is a mixture of CH_4, ethane, and lesser amounts of hydrogen and light hydrocarbons with trace amounts of ammonia and H_2S.

For steam production, petroleum coke, resulting from the coking process, is a free fuel of choice. Petroleum coke, primarily from the fluid catalytic cracking unit (FCCU), is burned continuously to regenerate the FCCU catalyst, with the heat of combustion captured in a steam boiler. The main supplemental fuel for steam generation is natural gas.

Some refineries are major cogenerators of steam and electricity. Cogeneration, or combined heat and power (CHP), increases energy efficiency through onsite production of thermal energy and electricity from a single fuel source. As a result of cogeneration, purchased electricity (primarily used to power machines) is not as significant a source of indirect emissions attributed to petroleum refining as it is in other energy-intensive industries that do not produce their own electricity.

Other factors have influenced efficiency gains in refining plants. Consolidation has resulted in an industry dominated by a relatively small number of large, vertically integrated companies operating multiple facilities.[22] A result of this consolidation was the closing of smaller, less efficient plants over some time. Refineries have maintained a utilization of capacity between 90% and 95% between 1996 and 2005, compared to a rate of about 65% in the early 1980s.[23]

ExxonMobil Decision Tools for Increased Efficiency

In 2000, ExxonMobil developed its Global Energy Management System for energy conservation. Since then, the company's Baton Rouge Refinery has implemented a program for steam trap and steam leak repair, heat exchanger monitoring, and furnace air pre-heater upgrades, improving the refinery's energy efficiency by 12%. In addition, Exxon has achieved reductions in CO_2 and NO_X emissions, improved flare system reliability, increased capacity, and enhanced plant-wide reliability. The refinery received EPA's ENERGY STAR Award for these improvements.[24]

Air Emissions

Air emissions from petroleum refining include CAPs, GHGs, and chemicals reported to TRI. In general, the "toxic chemicals" tracked by TRI are found in the raw materials and fuels used in the refining process, and can be generated in byproducts or end products. CAPs and GHGs are generated as combustion byproducts from onsite combustion of fuels.

Air Emissions Reported to TRI

In 2005, 163 facilities[25] in the petroleum refining industry reported 42.2 million lbs. of absolute air emissions to TRI. Between 1996 and 2005, TRI-reported air emissions declined by 31%, as shown in Figure 2a. When normalized by crude oil inputs into refineries, air emissions decreased by 36% over the 10 years, as shown in Figure 2b.[26]

To consider toxicity of air emissions, EPA's Risk-Screening Environmental Indicators (RSEI) model assigns every TRI chemical a relative toxicity weight, then multiplies the pounds of media-specific releases (e.g., pounds of mercury released to air) by a chemical-specific toxicity weight to calculate a relative Toxicity Score. RSEI methodological considerations are discussed in greater detail in the Data Guide, which explains the underlying assumptions and important limitations of RSEI.

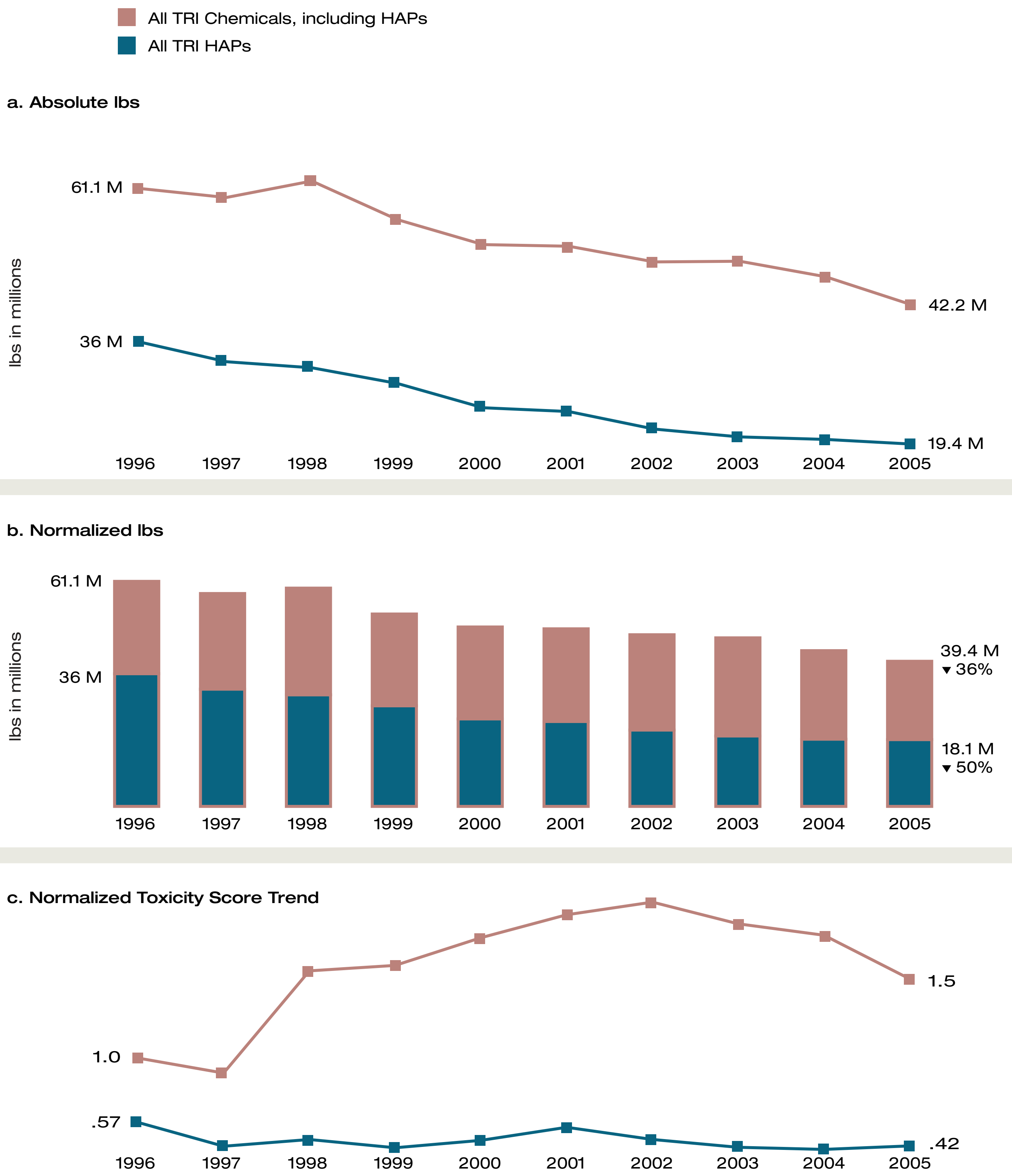
Data are not reported to TRI in sufficient detail to distinguish which forms of certain chemicals within a chemical category are being emitted. For chemical categories such as chromium, the toxicity model conservatively assumes that chemicals are emitted in the form with the highest toxicity weight (e.g., hexavalent chromium); thus, Toxicity Scores are overestimated for some chemical categories.

Summing the Toxicity Scores for all of the air emissions reported to TRI by the sector produces the trend illustrated in Figure 2c. As shown in Figures 2b and 2c, while the normalized reported lbs. of TRI emissions to air decreased 36% since 1996, the normalized Toxicity Score increased overall by 50%. Sulfuric acid, which has a relatively high toxicity weight, drove the Toxicity Score over the 10-year period and accounted for approximately three-quarters of the 2005 Toxicity Score. Sulfuric acid resulting from petroleum refinery operations is related to sulfur dioxide (SO_2) emissions. The presence of sulfur compounds in many refinery processes, together with high temperatures, can result in the formation and release of sulfuric acid. Decreases in refinery SO_2 emissions, then, result in corresponding decreases in the generation of sulfuric acid.

The TRI list of toxic chemicals includes all but six of the HAPs regulated under the CAA. Refinery processes emit a variety of organic, inorganic, and metal HAPs. Process vents, storage vessels, and wastewater streams emit organic HAPs, accounting for most of the total mass of HAP emissions from petroleum refineries. Other sources of HAP emissions are loading racks, marine tank vessel loading operations, and equipment leaks. In absolute pounds, HAPs accounted for 46% of the TRI chemicals emitted to air and 28% of the Toxicity Score in 2005. Between 1996 and 2005, the trend for HAP emissions follows the same declining trend as for all TRI air emissions.[27]

FIGURE 2

Air Emissions Reported to TRI 1996–2005



Note:
Normalized by annual crude oil inputs into refineries.

Sources: U.S. Environmental Prote tion Agency, U S Department of Energy

Table 6 presents the top TRI-reported chemicals emitted to air by petroleum refineries in 2005, based on three indicators. Each indicator provides data that environmental managers, trade associations, or government agencies might use in considering sector-based environmental management strategies.

1) Absolute Pounds Reported. Ammonia and sulfuric acid were the top-ranked chemicals based on the pounds of each chemical emitted to air in 2005.
2) Percentage of Toxicity Score. Sulfuric acid was the top-ranked chemical based on Toxicity Score.
3) Number of Facilities Reporting. Benzene and toluene were the most frequently reported chemicals, with almost all the TRI filers in the sector reporting emissions of these chemicals.

The CAA requires refineries to implement a Leak Detection and Repair (LDAR) program to monitor and fix equipment leaking fugitive emissions. In 1997, API commissioned a study of 11.5 million refinery components. The study showed more than 90% of controllable fugitive emissions are from about 0.1% of all components. Analyses also indicated that "Smart LDAR" programs focused on finding and repairing these few high-leak areas could result in significant improvements in environmental performance.

Some Smart LDAR techniques use emerging optical imaging technologies to target significant leakers, with remote sensing and real-time detection capabilities to scan process areas containing potential leaks. Significant leaks are then detected on the spot using infrared light, facilitating rapid repairs and minimizing potential environmental, safety, and health impacts.

TABLE 6

Top TRI Air Emissions 2005

Chemical	Absolute Pounds Reported[1]	Percentage Toxicity Score	Number of Facilities Reporting[2]
Ammonia	8,574,000[3]	1%	107
Benzene[4]	2,099,000	1%	152
Chlorine	146,000	6%	36
Chromium	4,000	2%[5]	20
Ethyl Benzene	624,000	<1%	145
N-Hexane	4,146,000	<1%	147
Nickel	45,000	8%	65
Polycyclic Aromatic Compounds	67,000	5%	129
Propylene	3,121,000	<1%	113
Sulfuric Acid	8,015,000	70%	67
Toluene	3,785,000	<1%	150
Xylene	2,652,000	<1%	147
Percentage of Sector Total	79%[6]	93%[7]	98%[8]

Notes:
1. Total sector air releases: 42 million lbs.
2. 163 total TRI reporters in the sector.
3. Red indicates that the chemical is one of the top five chemicals reported in the given category.
4. *Italics* indicate a hazardous air pollutant under section 112 of Clean Air Act.
5. Calculation of Toxicity Score for chromium conservatively assumed that all chromium emissions were hexavalent chromium, the most toxic form, with significantly higher toxicity weights than trivalent chromium. However, hexavalent chromium may not constitute a majority of the sector's chromium releases. Thus, RSEI analyses may overestimate the relative harmfulness of chromium emissions.
6. Chemicals in this list represent 79% of the sector's air emissions.
7. Chemicals in this list represent 93% of the sector's Toxicity Score.
8. 98% of facilities reported emitting one or more chemicals in this list.

Source: U.S. Environmental Protection Agency

Criteria Air Pollutants

Table 7 shows CAP and VOC emissions from petroleum refineries for 2002.

TABLE 7

Criteria Air Pollutant and VOC Emissions 2002

	Tons
SO_2	339,000
NO_X	195,000
PM_{10}	28,000
$PM_{2.5}$	23,000
CO	145,000
VOCs	125,000

Note:
PM_{10} includes $PM_{2.5}$ emissions.

Source: U.S. Environmental Protection Agency

Greenhouse Gases

The combustion of fossil fuels generates direct GHG emissions from petroleum refineries, and steam production and process heating are the two processes requiring the greatest combustion. In CH_4 emissions, petroleum refiners released an estimated 28.4 million metric tons of CO_2 equivalent in 2005, an increase of 7% since 1996.[28] Within refineries, vented emissions account for about 87% of the GHG emissions, while fugitive and combustion emissions account for 6% and 7% respectively. Most fugitive CH_4 emissions are leaks from the fuel gas system.[29]

In response to the U.S. Department of Energy's Climate VISION program, API began a Climate Challenge in which member refineries have committed to improve in energy efficiency 10% by 2012. Representative activities include developing GHG emissions management plans, setting numerical targets for improving energy efficiency, and reducing emissions. Specific strategies include expanding cogeneration, gasifying refinery residuals for use as fuel, reducing venting and flaring as well as fugitive methane emissions, conducting research and development into carbon sequestration and storage, deploying renewable energy technologies, and improving methods for tracking GHG emissions.

Water Use and Discharges

Petroleum refiners use 1-2 billion gallons of water daily, principally for process cooling systems.[30] Because they use relatively large volumes of water, refineries are often located near water sources (e.g., beside riverbanks and other shoreline locations).

Refinery operations generate process wastewater as well as surface water runoff. Wastewater characteristics and quantities differ among facilities and are driven by individual petroleum refining configurations. Processes to refine heavy crude, for example, tend to generate significant amounts of ammonia and suspended solids. In 2005, 121 refineries reported water discharges of TRI chemicals totaling 17.7 million pounds. This was a 52% increase in reported absolute pounds since 1996, and a 42% increase overall, when normalized by crude oil inputs to refineries. Nitrate compounds, reported by 62 facilities, and ammonia accounted for almost all (97%) of the reported discharges.[31]

Wastewater from petroleum refining typically requires multiple steps to remove contaminants, recover product, and recycle process fluids prior to discharge. Refiners often lessen discharge quantities, treatment burdens, and associated costs by separating the various waste streams of cooling and process water, sanitation and sewage, stormwater, and other streams. In addition to being regulated for direct discharges and discharges to Publicly Owned Treatment Works, refineries with materials exposed to precipitation are regulated for stormwater runoff, sometimes under a general permit that provides sector-specific limits on pollutants such as zinc, nickel, lead, ammonia, nitrates, and total suspended solids.

Waste Generation and Management

Wastes from petroleum refining operations can be generated from process-related functions or other activities, such as pollution prevention (e.g., control devices) or remediation of contamination. Refineries also generate wastes from handling petroleum products and treating wastewater. Typical refinery wastes are sludges, spent caustics, spent process catalysts, filter clay, and incinerator ash.

Hazardous Waste Management

In 2005, the sector reported generating 5.1 million tons of hazardous waste. The hazardous waste management method most utilized in refining was disposal, which accounted for 84% of wastes managed in 2005.

Waste Management Reported to TRI

In 2005, refineries reported a total of 1 billion absolute pounds of chemicals released, disposed, or managed through treatment, energy recovery, or recycling. This was a 22% decrease in the reported amount of waste managed since 1996, when normalized by crude oil inputs to refineries.

Figure 3 shows how this waste was managed. In 2005, 54% was treated, 23% was recovered for energy use, and 17% was recycled, while 6% of TRI-reported waste was disposed or released. Energy recovery appeared to be the principal waste management method early in the decade; treatment was the predominant management method in recent years, accounting for 54% of the total pounds of TRI chemicals managed in 2005. Flaring is presently a major means of onsite treatment at many petroleum refineries; the industry is addressing associated GHG emissions under API's Climate Challenge.

In 2005, refineries reported that 6.3 million lbs. of TRI chemicals were disposed to land or transferred to offsite locations for disposal. Ammonia, zinc, and nickel disposals accounted for almost half of the total pounds disposed, as shown in Table 8. Most petroleum refinery TRI hazardous waste disposals utilized underground injection, although 43% relied upon landfill disposal.[32]

TABLE 8

Top TRI Disposals 2005

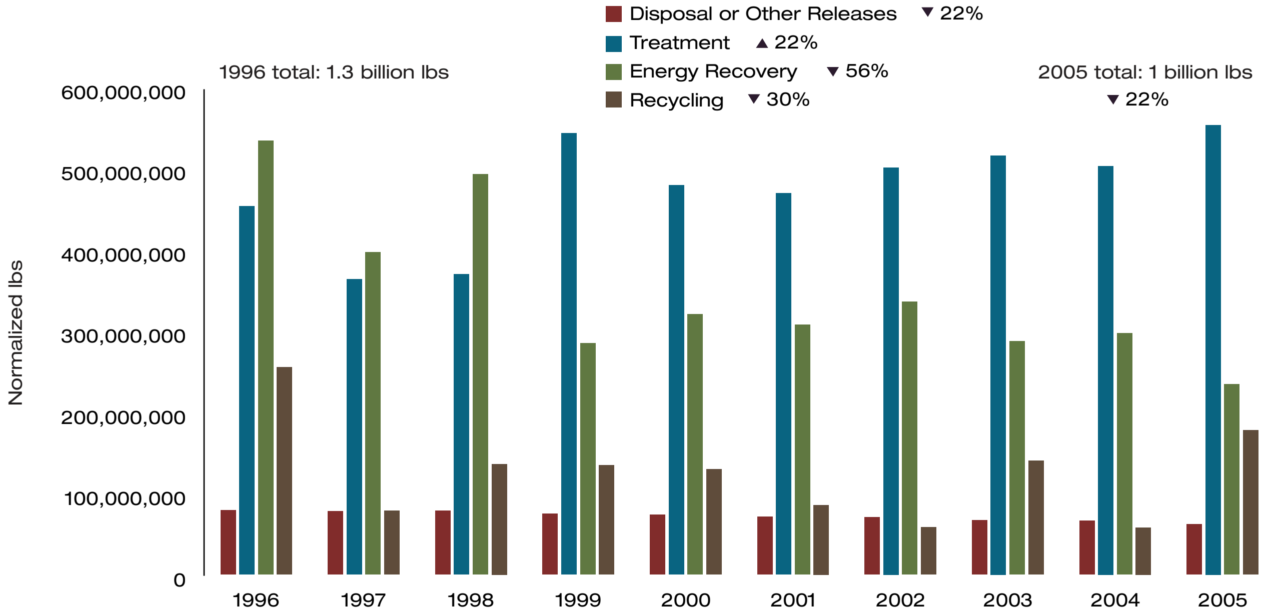
Chemical	Absolute Pounds Reported[1]	Number of Facilities Reporting[2]
Ammonia	1,337,000[3]	29
Asbestos (Friable)	730,000	2
Benzene	107,000	98
Ethylbenzene	22,000	100
Lead	187,000	111
Molybdenum Trioxide	440,000	32
Nickel	817,000	64
Toluene	127,000	101
Xylene (Mixed Isomers)	105,000	104
Zinc	826,000	32
Percentage of Sector Total	74%[4]	81%[5]

Notes:
1. Total sector disposals: 6.3 million lbs.
2. 163 total TRI reporters in the sector.
3. Red indicates that the chemical is one of the top five chemicals reported in the given category.
4. Chemicals in this list represent 74% of the sector's disposals.
5. 81% of facilities reported disposals of one or more chemicals in this list.

Source: U.S. Environmental Protection Agency

FIGURE 3

TRI Waste Management 1996–2005



Notes:

1. Normalized by annual crude oil inputs into refineries.
2. Disposal or other releases include air releases, water discharges, and land disposals.

Sources: U.S. Environmental Protection Agency, U.S. Department of Energy

Additional Environmental Management Activities for E&P and Refining

Several Oil & Gas sector environmental initiatives include both E&P and refining operations. For instance, EPA's Natural Gas STAR program engages all segments of the natural gas industry—production, gathering, processing, transmission, and distribution—to identify and implement technologies and practices to reduce emissions of CH_4. Natural Gas STAR identifies best management practices (BMPs) selected through a collaborative process involving EPA and natural gas industry advisers. The BMPs identify areas of operation where emissions can be reduced cost effectively.

In 1999, Natural Gas STAR producer partners reported saving 17.4 Bcf of CH_4, representing emissions that were prevented and natural gas that was retained in the system to be sold. EPA expanded the program in 2000 to include companies that gather and process natural gas. In 2005, partners reported more than 33.2 Bcf of CH_4 emissions reductions.[33]

The American Exploration & Production Council (AXPC) is an official endorser of the Natural Gas STAR program, in which 16 AXPC member companies actively participate. Implementing Natural Gas STAR–recommended technologies and management practices, these AXPC member companies collectively reduced CH_4 emissions by 103 Bcf, representing savings of $720 million.

Marathon's Multi-Media Environmental Management Approach

Marathon Petroleum Company–Louisiana Refinery Division in Garyville, LA, is the last petroleum refinery built in the United States (1976) and the only refinery in EPA's Performance Track program.[34] In 2005, Marathon-Garyville announced plans for a major expansion to add 185,000 barrels per stream day of crude oil capacity. During the permitting process, Marathon agreed to reduce NO_x emissions beyond Best Achievable Control Technology requirements and to impose CO limits below burner manufacturer specifications. Marathon also installed four real-time ambient air monitoring stations and plans to upgrade the wastewater treatment system to ensure no additional NPDES permit allocations will be necessary. Marathon already has an onsite wastewater treatment plant that uses water from the adjacent Mississippi River and returns it to the river cleaner than it was when withdrawn.[35]