3.   Energy

Energy-related activities were the primary sources of U.S. anthropogenic greenhouse gas emissions, accounting for 86 percent of total emissions on a carbon dioxide (CO_2) equivalent basis in 2006. This included 97, 37, and 13 percent of the nation's CO_2, methane (CH_4), and nitrous oxide (N_2O) emissions, respectively. Energy-related CO_2 emissions alone constituted 83 percent of national emissions from all sources on a CO_2 equivalent basis, while the non-CO_2 emissions from energy-related activities represented a much smaller portion of total national emissions (4 percent collectively).

Emissions from fossil fuel combustion comprise the vast majority of energy-related emissions, with CO_2 being the primary gas emitted (see Figure 3-1). Globally, approximately 28,193 Tg of CO_2 were added to the atmosphere through the combustion of fossil fuels in 2005, of which the United States accounted for about 20 percent.[1] Due to the relative importance of fossil fuel combustion-related CO_2 emissions, they are considered separately, and in more detail than other energy-related emissions (see Figure 3-2). Fossil fuel combustion also emits CH_4 and N_2O, as well as indirect greenhouse gases such as nitrogen oxides (NO_x), carbon monoxide (CO), and non-CH_4 volatile organic compounds (NMVOCs). Mobile fossil fuel combustion was the second largest source of N_2O emissions in the United States, and overall energy-related activities were collectively the largest source of these indirect greenhouse gas emissions.

Figure 3-1: 2006 Energy Chapter Greenhouse Gas Sources

Figure 3-2: 2006 U.S. Fossil Carbon Flows (Tg CO_2 Eq.)

Energy-related activities other than fuel combustion, such as the production, transmission, storage, and distribution of fossil fuels, also emit greenhouse gases. These emissions consist primarily of fugitive CH_4 from natural gas systems, petroleum systems, and coal mining. Smaller quantities of CO_2, CO, NMVOCs, and NO_x are also emitted.

The combustion of biomass and biomass-based fuels also emits greenhouse gases. CO_2 emissions from these activities, however, are not included in national emissions totals because biomass fuels are of biogenic origin. It is assumed that the C released during the consumption of biomass is recycled as U.S. forests and crops regenerate, causing no net addition of CO_2 to the atmosphere. The net impacts of land-use and forestry activities on the C cycle are accounted for separately within the Land Use, Land-Use Change, and Forestry chapter. Emissions of other greenhouse gases from the combustion of biomass and biomass-based fuels are included in national totals under stationary and mobile combustion.

Table 3-1 summarizes emissions from the Energy sector in units of teragrams of CO_2 equivalents (Tg CO_2 Eq.), while unweighted gas emissions in gigagrams (Gg) are provided in Table 3-2. Overall, emissions due to energy-related activities were 6,076.9 Tg CO_2 Eq. in 2006, an increase of 17 percent since 1990.

Table 3-1: CO_2, CH_4, and N_2O Emissions from Energy (Tg CO_2 Eq.)

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[1] Global CO_2 emissions from fossil fuel combustion were taken from Energy Information Administration *International Energy Annual 2005* <http://www.eia.doe.gov/emeu/iea/carbon.html> EIA (2007).

Gas/Source	1990	1995	2000	2001	2002	2003	2004	2005	2006
CO$_2$	**4,886.4**	**5,215.5**	**5,765.7**	**5,686.4**	**5,749.1**	**5,796.6**	**5,878.8**	**5,920.5**	**5,825.6**
Fossil Fuel Combustion	4,724.1	5,032.4	5,577.1	5,507.4	5,564.8	5,617.0	5,681.4	5,731.0	5,637.9
Electricity Generation	1,809.6	1,939.3	2,282.3	2,244.3	2,253.7	2,283.1	2,314.9	2,380.2	2,328.2
Transportation	1,485.1	1,599.4	1,798.2	1,775.6	1,828.9	1,807.6	1,856.4	1,869.8	1,856.0
Industrial	844.9	876.5	860.3	852.5	854.8	856.0	857.7	847.3	862.2
Residential	340.1	356.5	372.1	363.6	360.5	382.9	368.3	358.5	326.5
Commercial	216.1	225.8	228.0	222.3	222.8	236.5	230.6	221.9	210.1
U.S. Territories	28.3	35.0	36.2	49.0	44.0	51.0	53.5	53.2	54.9
Non-Energy Use of Fuels	117.2	133.2	141.4	131.9	135.9	131.8	148.9	139.1	138.0
Natural Gas Systems	33.7	33.8	29.4	28.8	29.6	28.4	28.1	29.5	28.5
Municipal Solid Waste Combustion	10.9	15.7	17.5	18.0	18.5	19.1	20.1	20.7	20.9
Petroleum Systems	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
*Wood Biomass and Ethanol Consumption**	*219.3*	*236.8*	*227.3*	*203.2*	*204.4*	*209.5*	*224.8*	*227.4*	*234.7*
*International Bunker Fuels**	*113.7*	*100.6*	*101.1*	*97.6*	*89.1*	*103.6*	*119.0*	*122.6*	*127.1*
CH$_4$	**260.8**	**246.8**	**234.5**	**232.0**	**226.9**	**224.6**	**217.4**	**202.4**	**203.3**
Natural Gas Systems	124.7	128.1	126.5	125.3	124.9	123.3	114.0	102.5	102.4
Coal Mining	84.1	67.1	60.4	60.3	56.8	56.9	59.8	57.1	58.5
Petroleum Systems	33.9	32.0	30.3	30.2	29.9	29.2	28.7	28.3	28.4
Stationary Combustion	7.4	7.2	6.7	6.2	6.2	6.4	6.6	6.5	6.2
Abandoned Underground Coal Mines	6.0	8.2	7.4	6.7	6.2	6.0	5.8	5.6	5.4
Mobile Combustion	4.7	4.3	3.4	3.3	3.0	2.7	2.6	2.5	2.4
*International Bunker Fuels**	*0.2*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.2*	*0.2*
N$_2$O	**56.8**	**67.3**	**67.5**	**64.4**	**60.4**	**57.1**	**54.7**	**51.5**	**48.0**
Mobile Combustion	43.5	53.4	52.5	49.9	45.9	42.3	39.7	36.3	33.1
Stationary Combustion	12.8	13.4	14.6	14.1	14.0	14.4	14.6	14.8	14.5
Municipal Solid Waste Combustion	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4
*International Bunker Fuels**	*1.0*	*0.9*	*0.9*	*0.9*	*0.8*	*0.9*	*1.1*	*1.1*	*1.1*
Total	**5,203.9**	**5,529.6**	**6,067.8**	**5,982.8**	**6,036.3**	**6,078.3**	**6,150.9**	**6,174.4**	**6,076.9**

* These values are presented for informational purposes only and are not included or are already accounted for in totals.
Note: Totals may not sum due to independent rounding.

Table 3-2: CO$_2$, CH$_4$, and N$_2$O Emissions from Energy (Gg)

Gas/Source	1990	1995	2000	2001	2002	2003	2004	2005	2006
CO$_2$	**4,886,370**	**5,215,509**	**5,765,732**	**5,686,382**	**5,749,059**	**5,796,639**	**5,878,815**	**5,920,526**	**5,825,631**
Fossil Fuel Combustion	4,724,146	5,032,416	5,577,072	5,507,406	5,564,795	5,617,047	5,681,363	5,731,045	5,637,931
Non-Energy Use of Fuels	117,170	133,234	141,427	131,887	135,857	131,772	148,931	139,057	137,980
Natural Gas Systems	33,729	33,806	29,390	28,793	29,629	28,445	28,122	29,462	28,504
Municipal Solid Waste Combustion	10,950	15,712	17,518	17,971	18,458	19,058	20,097	20,673	20,922
Petroleum Systems	376	341	325	325	320	316	302	287	293
*Wood Biomass and Ethanol Consumption**	*219,341*	*236,775*	*227,276*	*203,163*	*204,351*	*209,537*	*224,825*	*227,366*	*234,726*

	1990	1995	2000	2001	2002	2003	2004	2005	2006
*International Bunker Fuels**	*113,683*	*100,627*	*101,125*	*97,563*	*89,101*	*103,583*	*118,975*	*122,580*	*127,097*
CH₄	**12,417**	**11,754**	**11,168**	**11,048**	**10,804**	**10,693**	**10,353**	**9,636**	**9,679**
Natural Gas Systems	5,937	6,098	6,024	5,968	5,946	5,874	5,426	4,880	4,877
Coal Mining	4,003	3,193	2,874	2,874	2,707	2,709	2,846	2,717	2,784
Petroleum Systems	1,612	1,524	1,442	1,436	1,422	1,390	1,368	1,346	1,354
Stationary Combustion	353	341	316	295	295	306	311	308	296
Abandoned Underground Coal Mines	288	392	350	319	293	284	276	265	257
Mobile Combustion	224	205	162	157	141	131	126	119	112
*International Bunker Fuels**	*8*	*6*	*6*	*5*	*4*	*6*	*7*	*7*	*7*
N₂O	**183**	**217**	**218**	**208**	**195**	**184**	**176**	**166**	**155**
Mobile Combustion	140	172	169	161	148	137	128	117	107
Stationary Combustion	41	43	47	46	45	46	47	48	47
Municipal Solid Waste Combustion	2	1	1	1	1	1	1	1	1
*International Bunker Fuels**	*3*	*3*	*3*	*3*	*3*	*3*	*3*	*4*	*4*

* These values are presented for informational purposes only and are not included or are already accounted for in totals.

Note: Totals may not sum due to independent rounding.

3.1. Carbon Dioxide Emissions from Fossil Fuel Combustion (IPCC Source Category 1A)

CO_2 emissions from fossil fuel combustion in 2006 decreased by 1.6 percent from the previous year. This decrease is primarily a result of the restraint on fuel consumption caused by rising fuel prices, primarily in the transportation sector, an increase in the cost of electricity, and decreases in the cost of natural gas.   Additionally, warmer winter conditions in 2006 decreased the demand for heating fuels. In 2006, CO_2 emissions from fossil fuel combustion were 5,637.9 Tg CO_2 Eq., or 19 percent above emissions in 1990 (see Table 3-3).[2]

Table 3-3: CO_2 Emissions from Fossil Fuel Combustion by Fuel Type and Sector (Tg CO_2 Eq.)

Fuel/Sector	1990	1995	2000	2001	2002	2003	2004	2005	2006
Coal	**1,698.9**	**1,805.4**	**2,053.2**	**1,996.3**	**2,002.8**	**2,043.1**	**2,058.4**	**2,094.1**	**2,065.3**
Residential	2.9	1.7	1.0	1.0	1.1	1.2	1.2	0.9	0.6
Commercial	11.8	11.1	8.2	8.4	8.4	7.9	9.7	9.2	6.2
Industrial	152.3	143.0	133.5	133.5	123.4	124.0	126.2	122.0	122.0
Transportation	NE	NE	NE	NE	NE	NE	NE	NE	NE
Electricity Generation	1,531.3	1,648.7	1,909.6	1,852.3	1,868.3	1,906.2	1,917.6	1,958.4	1,932.4
U.S. Territories	0.6	0.9	0.9	1.0	1.7	3.8	3.6	3.7	4.1
Natural Gas	**1,011.5**	**1,172.0**	**1,220.5**	**1,175.3**	**1,227.6**	**1,200.3**	**1,180.1**	**1,173.9**	**1,155.1**

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[2] An additional discussion of fossil fuel emission trends is presented in the Trends in U.S. Greenhouse Gas Emissions Chapter.

Residential	239.8	264.4	270.6	260.3	265.0	277.5	264.5	262.7	237.5
Commercial	143.1	165.4	172.7	165.1	171.0	176.7	170.0	163.2	154.1
Industrial	416.3	474.4	460.0	425.0	447.2	433.0	415.5	394.5	389.3
Transportation	36.1	38.4	35.7	34.1	37.2	33.4	32.0	33.2	33.2
Electricity Generation	176.2	229.5	280.9	289.6	306.0	278.3	296.8	319.1	339.6
U.S. Territories	NO	NO	0.7	1.2	1.2	1.4	1.3	1.3	1.4
Petroleum	**2,013.3**	**2,054.7**	**2,303.0**	**2,335.5**	**2,334.0**	**2,373.3**	**2,442.5**	**2,462.7**	**2,417.1**
Residential	97.4	90.5	100.5	102.2	94.4	104.2	102.5	95.0	88.5
Commercial	61.2	49.3	47.2	48.8	43.4	51.8	50.9	49.6	49.8
Industrial	276.3	259.0	266.8	294.0	284.3	299.1	316.0	330.9	350.9
Transportation	1,449.0	1,561.0	1,762.5	1,741.6	1,791.7	1,774.2	1,824.4	1,836.7	1,822.8
Electricity Generation	101.8	60.7	91.5	102.0	79.1	98.1	100.1	102.3	55.7
U.S. Territories	27.6	34.0	34.6	46.8	41.1	45.8	48.6	48.2	49.4
Geothermal*	**0.40**	**0.34**	**0.36**	**0.35**	**0.37**	**0.37**	**0.38**	**0.38**	**0.38**
Total	**4,724.1**	**5,032.4**	**5,577.1**	**5,507.4**	**5,564.8**	**5,617.0**	**5,681.4**	**5,731.0**	**5,637.9**

NE (Not estimated)
NO (Not occurring)
* Although not technically a fossil fuel, geothermal energy-related CO_2 emissions are included for reporting purposes.
Note: Totals may not sum due to independent rounding.

Trends in CO_2 emissions from fossil fuel combustion are influenced by many long-term and short-term factors. On a year-to-year basis, the overall demand for fossil fuels in the United States and other countries generally fluctuates in response to changes in general economic conditions, energy prices, weather, and the availability of non-fossil alternatives. For example, in a year with increased consumption of goods and services, low fuel prices, severe summer and winter weather conditions, nuclear plant closures, and lower precipitation feeding hydroelectric dams, there would likely be proportionally greater fossil fuel consumption than a year with poor economic performance, high fuel prices, mild temperatures, and increased output from nuclear and hydroelectric plants.

Longer-term changes in energy consumption patterns, however, tend to be more a function of aggregate societal trends that affect the scale of consumption (e.g., population, number of cars, and size of houses), the efficiency with which energy is used in equipment (e.g., cars, power plants, steel mills, and light bulbs), and social planning and consumer behavior (e.g., walking, bicycling, or telecommuting to work instead of driving).

CO_2 emissions also depend on the source of energy and its carbon (C) intensity. The amount of C in fuels varies significantly by fuel type. For example, coal contains the highest amount of C per unit of useful energy. Petroleum has roughly 75 percent of the C per unit of energy as coal, and natural gas has only about 55 percent.[3] Producing a unit of heat or electricity using natural gas instead of coal can reduce the CO_2 emissions associated with energy consumption, and using nuclear or renewable energy sources (e.g., wind) can essentially eliminate emissions (see Box 3-2). Table 3-4 shows annual changes in emissions during the last five years for coal, petroleum, and natural gas in selected sectors.

Table 3-4: Annual Change in CO_2 Emissions from Fossil Fuel Combustion for Selected Fuels and Sectors (Tg CO_2 Eq. and Percent)

Sector	Fuel Type	2002 to 2003		2003 to 2004		2004 to 2005		2005 to 2006	
Electricity Generation	Coal	38.0	2.0%	11.4	0.6%	40.8	2.1%	-26.0	-1.3%
Electricity Generation	Natural Gas	-27.6	-9.0%	18.5	6.6%	22.3	7.5%	20.5	6.4%
Electricity Generation	Petroleum	19.0	24.0%	2.0	2.0%	2.2	2.2%	-46.6	-45.5%
Transportation [a]	Petroleum	-17.5	-1.0%	50.2	2.8%	12.3	0.7%	-13.9	-0.8%
Residential	Natural Gas	12.5	4.7%	-12.9	-4.7%	-1.9	-0.7%	-25.2	-9.6%

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[3] Based on national aggregate carbon content of all coal, natural gas, and petroleum fuels combusted in the United States.

Commercial	Natural Gas	5.7	3.3%	-6.7	-3.8%	-6.8	-4.0%	-9.1	-5.6%
Industrial	Coal	0.6	0.5%	2.3	1.8%	-4.3	-3.4%	0.1	0.1%
Industrial	Natural Gas	-14.2	-3.2%	-17.5	-4.0%	-21.0	-5.1%	-5.2	-1.3%
All Sectors [b]	**All Fuels [b]**	**52.3**	**0.9%**	**64.3**	**1.1%**	**49.7**	**0.9%**	**-93.1**	**-1.6%**

[a] Excludes emissions from International Bunker Fuels.
[b] Includes fuels and sectors not shown in table.

In the United States, 82 percent of the energy consumed in 2006 was produced through the combustion of fossil fuels such as coal, natural gas, and petroleum (see Figure 3-3 and Figure 3-4). The remaining portion was supplied by nuclear electric power (8 percent) and by a variety of renewable energy sources (9 percent), primarily hydroelectric power and biofuels (EIA 2007a). Specifically, petroleum supplied the largest share of domestic energy demands, accounting for an average of 43 percent of total fossil fuel based energy consumption in 2006. Coal and natural gas followed in order of importance, each accounting for 28 percent of total consumption. Petroleum was consumed primarily in the transportation end-use sector, the vast majority of coal was used in electricity generation, and natural gas was broadly consumed in all end-use sectors except transportation (see Figure 3-5) (EIA 2007a).

Figure 3-3: 2006 U.S. Energy Consumption by Energy Source

Figure 3-4: U.S. Energy Consumption (Quadrillion Btu)

Figure 3-5: 2006 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type

Fossil fuels are generally combusted for the purpose of producing energy for useful heat and work. During the combustion process, the C stored in the fuels is oxidized and emitted as CO_2 and smaller amounts of other gases, including CH_4, CO, and NMVOCs.[4] These other C containing non-CO_2 gases are emitted as a by-product of incomplete fuel combustion, but are, for the most part, eventually oxidized to CO_2 in the atmosphere. Therefore, it is assumed that all the C in fossil fuels used to produce energy is eventually converted to atmospheric CO_2.

[BEGIN BOX]

Box 3-1: Weather and Non-Fossil Energy Effects on CO_2 from Fossil Fuel Combustion Trends

In 2006, weather conditions became warmer in the winter and slightly cooler in the summer, compared to 2005.

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[4] See the sections entitled Stationary Combustion and Mobile Combustion in this chapter for information on non-CO_2 gas emissions from fossil fuel combustion.

The winter was significantly warmer than usual, with heating degree days in the United States 12 percent below normal (see Figure 3-6). Warmer winter conditions led to a decrease in demand for heating fuels. Summer temperatures were substantially warmer than usual, with cooling degree days 10 percent above normal (see Figure 3-7) (EIA 2007f),[5] however the demand for electricity only increased slightly due to the cooler summer conditions compared to 2005.

Figure 3-6: Annual Deviations from Normal Heating Degree Days for the United States (1950–2006)

Figure 3-7: Annual Deviations from Normal Cooling Degree Days for the United States (1950–2006)

Although no new U.S. nuclear power plants have been constructed in recent years, the utilization (i.e., capacity factors[6]) of existing plants in 2006 remained high at just under 90 percent. Electricity output by hydroelectric power plants increased in 2006 by approximately 7 percent. Electricity generated by nuclear plants in 2006 provided almost 3 times as much of the energy consumed in the United States as hydroelectric plants (EIA 2007a). Aggregate nuclear and hydroelectric power plant capacity factors since 1973 are shown in Figure 3-8.

Figure 3-8: Aggregate Nuclear and Hydroelectric Power Plant Capacity Factors in the United States (1974–2006)

[END BOX]

For the purpose of international reporting, the Intergovernmental Panel on Climate Change (IPCC) (IPCC/UNEP/OECD/IEA 1997) recommends that particular adjustments be made to national fuel consumption statistics. Certain fossil fuels can be manufactured into plastics, asphalt, lubricants, or other products. A portion of the C consumed for these non-energy products can be stored (i.e., sequestered) indefinitely. To account for the fact that the C in these fuels ends up in products instead of being combusted (i.e., oxidized and released into the atmosphere), consumption of fuels for non-energy purposes is estimated and subtracted from total fuel consumption estimates. Emissions from non-energy uses of fuels are estimated in the Carbon Emitted and Stored in Products from Non-Energy Uses of Fossil Fuels section in this chapter.

According to the UNFCCC reporting guidelines, CO_2 emissions from the consumption of fossil fuels for aviation and marine international transport activities (i.e., international bunker fuels) should be reported separately, and not

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[5] Degree days are relative measurements of outdoor air temperature. Heating degree days are deviations of the mean daily temperature below 65° F, while cooling degree days are deviations of the mean daily temperature above 65° F. Heating degree days have a considerably greater affect on energy demand and related emissions than do cooling degree days. Excludes Alaska and Hawaii. Normals are based on data from 1971 through 2000. The variation in these normals during this time period was ±10 percent and ±14 percent for heating and cooling degree days, respectively (99 percent confidence interval).

[6] The capacity factor is defined as the ratio of the electrical energy produced by a generating unit for a given period of time to the electrical energy that could have been produced at continuous full-power operation during the same period (EIA 2007a).

included in national emission totals. Estimates of international bunker fuel emissions for the United States are provided in Table 3-5, and explained in detail later in the chapter.

Table 3-5: CO_2 Emissions from International Bunker Fuels (Tg CO_2 Eq.)*

Vehicle Mode	1990		1995		2000	2001	2002	2003	2004	2005	2006
Aviation	45.7		50.2		59.9	58.7	61.1	58.8	64.9	67.5	71.1
Marine	68.0		50.4		41.3	38.9	28.0	44.8	54.1	55.1	56.0
Total	**113.7**		**100.6**		**101.1**	**97.6**	**89.1**	**103.6**	**119.0**	**122.6**	**127.1**

* See International Bunker Fuels section for additional detail.
Note: Totals may not sum due to independent rounding.

End-Use Sector Consumption

An alternative method of presenting CO_2 emissions is to allocate emissions associated with electricity generation to the sectors in which it is used. Four end-use sectors were defined: industrial, transportation, residential, and commercial. For the discussion below, electricity generation emissions have been distributed to each end-use sector based upon the sector's share of national electricity consumption. This method of distributing emissions assumes that each sector consumes electricity generated from an equally carbon-intensive mix of fuels and other energy sources. After the end-use sectors are discussed, emissions from electricity generation are addressed separately. Emissions from U.S. territories are also calculated separately due to a lack of end-use-specific consumption data. Table 3-6 and Figure 3-9 summarize CO_2 emissions from direct fossil fuel combustion and pro-rated electricity generation emissions from electricity consumption by end-use sector.

Table 3-6: CO_2 Emissions from Fossil Fuel Combustion by End-Use Sector (Tg CO_2 Eq.)

End-Use Sector	1990		1995		2000	2001	2002	2003	2004	2005	2006
Transportation	**1,488.1**		**1,602.5**		**1,801.6**	**1,779.2**	**1,832.3**	**1,811.8**	**1,860.9**	**1,874.5**	**1,861.0**
Combustion	1,485.1		1,599.4		1,798.2	1,775.6	1,828.9	1,807.6	1,856.4	1,869.8	1,856.0
Electricity	3.0		3.0		3.4	3.6	3.4	4.2	4.5	4.7	4.9
Industrial	**1,527.5**		**1,589.5**		**1,645.1**	**1,583.9**	**1,572.5**	**1,592.1**	**1,596.8**	**1,579.6**	**1,567.1**
Combustion	844.9		876.5		860.3	852.5	854.8	856.0	857.7	847.3	862.2
Electricity	682.5		713.1		784.7	731.4	717.7	736.1	739.0	732.3	704.9
Residential	**929.5**		**995.5**		**1,129.7**	**1,121.8**	**1,145.6**	**1,178.3**	**1,173.1**	**1,206.4**	**1,151.9**
Combustion	340.1		356.5		372.1	363.6	360.5	382.9	368.3	358.5	326.5
Electricity	589.4		639.0		757.6	758.1	785.1	795.4	804.9	847.9	825.4
Commercial	**750.8**		**810.0**		**964.6**	**973.5**	**970.3**	**983.8**	**997.1**	**1,017.3**	**1,003.0**
Combustion	216.1		225.8		228.0	222.3	222.8	236.5	230.6	221.9	210.1
Electricity	534.7		584.2		736.6	751.1	747.5	747.3	766.5	795.4	792.9
U.S. Territories	**28.3**		**35.0**		**36.2**	**49.0**	**44.0**	**51.0**	**53.5**	**53.2**	**54.9**
Total	**4,724.1**		**5,032.4**		**5,577.1**	**5,507.4**	**5,564.8**	**5,617.0**	**5,681.4**	**5,731.0**	**5,637.9**
Electricity Generation	**1,809.6**		**1,939.3**		**2,282.3**	**2,244.3**	**2,253.7**	**2,283.1**	**2,314.9**	**2,380.2**	**2,328.2**

Note: Totals may not sum due to independent rounding. Emissions from fossil fuel combustion by electricity generation are allocated based on aggregate national electricity consumption by each end-use sector.

Figure 3-9: 2006 End-Use Sector Emissions of CO_2 from Fossil Fuel Combustion

Transportation End-Use Sector

The transportation end-use sector accounted for 1,861.0 Tg CO_2 in 2006, representing 33 percent of total CO_2 emissions from fossil fuel combustion; the largest share of any end-use economic sector[7]. Fuel purchased in the U.S. for international aircraft and marine travel accounted for an additional 127.1 Tg CO_2 in 2006; these emissions are recorded as international bunkers, and are not included in U.S. totals according to UNFCCC reporting protocols. Among domestic transportation sources, light duty vehicles (including passenger cars and light-duty trucks) represented 62 percent of CO_2 emissions, medium- and heavy-duty trucks 22 percent, domestic commercial aircraft 7.6 percent, and other sources just over 8 percent. (See Table 3-7 for a detailed breakdown of CO_2 emissions by mode and fuel type.)

Domestic transportation CO_2 emissions increased by almost 25 percent (372.9 Tg) between 1990 and 2006, an annualized increase of 1.5 percent. From 2005 to 2006 transportation CO_2 emissions decreased by 0.7 percent. Almost all of the energy consumed by the transportation sector is petroleum-based, including motor gasoline, diesel fuel, jet fuel, and residual oil. Transportation sources also produce CH_4 and N_2O; these emissions are included beginning in Table 3-21 the "Mobile Combustion" Section. Annex 3.2 presents total emissions from all transportation and mobile sources, including CO_2, N_2O, CH_4, and HFCs.

Carbon dioxide emissions from passenger cars and light-duty trucks totaled 1,151.3 Tg in 2006, an increase of 21 percent (200.1 Tg) from 1990. The increase in light-duty CO_2 emissions is due primarily to the growth in vehicle travel, which substantially outweighed improvements in vehicle fuel economy. Light-duty vehicle miles traveled (VMT) increased 39 percent from 1990 to 2006; average vehicle fuel economy increased from 18.9 miles per gallon (mpg) in 1990 to 20.4 mpg in 2006, primarily reflecting the retirement of older vehicles. Among new vehicles sold annually, average fuel economy gradually declined from 1990 to 2006 (Figure 3-10), reflecting substantial growth in sales of light-duty trucks relative to passenger cars (Figure 3-11). Average new vehicle fuel economy improved in 2005 and 2006 as the market share of passenger cars increased in response to rising fuel prices.

Figure 3-10: Sales-Weighted Fuel Economy of New Passenger Cars and Light-Duty Trucks, 1990–2006

Figure 3-11: Sales of New Passenger Cars and Light-Duty Trucks, 1990–2006

Medium- and heavy-duty truck[8] CO_2 emissions increased by 76 percent (173.4 Tg) from 1990 to 2006, representing the largest percentage increase of any major transportation mode. Fuel economy for the medium- and heavy-duty truck fleet did not significantly improve over this period, and most likely declined from levels recorded in the late 1990s. Meanwhile, medium- and heavy-duty truck VMT increased by 52 percent. CO_2 from the domestic operation of commercial aircraft increased by 4 percent (5.4 Tg) from 1990 to 2006, well below the growth in travel activity (passenger miles traveled grew by 69 percent from 1990 to 2005, the most recent year of available data). The operational efficiency of commercial aircraft improved substantially because of a growing percentage of seats occupied per flight, improvements in the fuel efficiency of new aircraft, and the accelerated retirement of older, less fuel efficient aircraft. Across all categories of aviation[9], CO_2 emissions decreased by approximately 5.2 percent (9.4 Tg CO_2) between 1990 and 2006. This decline reflects a 56 percent decrease in

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[7] Note that electricity generation is the largest emitter of CO_2 when electricity is not distributed among end-use sectors.

[8] Includes "medium- and heavy-duty trucks" fueled by gasoline, diesel and LPG.

[9] Includes consumption of jet fuel and aviation gasoline. Does not include aircraft bunkers, which are not accounted for in national emission totals.

emissions from domestic military operations, which more than offset a small increase in domestic commercial and general aviation emissions. For further information on all greenhouse gas emissions from transportation sources, please refer to Table A-108 in Annex 3.2.

Table 3-7: CO_2 Emissions from Fossil Fuel Combustion in Transportation End-Use Sector (Tg CO_2 Eq.) [a]

Fuel/Vehicle Type	1990	1995	2000	2001	2002	2003	2004	2005	2006
Gasoline	**982.8**	**1,038.9**	**1,135.7**	**1,145.4**	**1,172.3**	**1,176.5**	**1,194.8**	**1181.2**	**1,170.0**
Passenger Cars	621.0	597.0	639.9	644.2	658.9	638.0	635.8	654.2	630.4
Light-Duty Trucks	308.9	389.9	446.0	449.4	461.3	491.5	511.6	476.0	488.0
Medium- and Heavy-Duty Trucks[b]	38.7	35.8	36.0	35.0	35.5	30.6	30.9	34.7	35.2
Buses	0.3	0.4	0.4	0.4	0.3	0.3	0.4	0.4	0.4
Motorcycles	1.7	1.8	1.8	1.7	1.7	1.6	1.7	1.6	1.9
Recreational Boats	12.1	14.1	11.6	14.6	14.6	14.5	14.4	14.3	14.1
Distillate Fuel Oil (Diesel)	**272.7**	**325.1**	**401.0**	**401.6**	**415.1**	**421.8**	**447.2**	**462.2**	**472.1**
Passenger Cars	7.8	7.7	3.6	3.6	3.7	4.2	4.3	4.2	4.1
Light-Duty Trucks	11.3	14.7	19.8	20.6	21.6	26.9	28.8	25.5	26.4
Medium- and Heavy-Duty Trucks[b]	188.3	234.9	305.1	305.1	318.8	320.0	332.5	356.5	365.4
Buses	7.9	8.6	10.1	9.2	8.7	9.4	13.4	10.6	10.9
Rail	35.1	39.2	41.7	41.8	41.5	42.4	44.7	45.1	46.0
Recreational Boats	1.9	2.3	2.7	2.8	2.9	3.0	3.0	3.1	3.205
Ships and Other Boats	8.8	8.6	11.7	13.2	12.8	8.3	10.0	7.9	7.4
Ships (Bunkers)	11.6	9.2	6.3	5.3	5.1	7.6	10.5	9.3	8.7
Jet Fuel	**222.6**	**222.1**	**253.8**	**242.8**	**236.8**	**231.5**	**239.8**	**246.3**	**239.5**
Commercial Aircraft - Domestic	136.7	143.1	164.2	152.9	146.1	143.9	142.9	150.4	142.1
Military Aircraft	33.9	23.5	20.5	22.5	20.4	19.9	20.4	16.9	14.8
General Aviation Aircraft	6.3	5.3	9.2	8.8	9.1	8.8	11.5	11.4	11.4
Aircraft (Bunkers)	45.7	50.2	59.9	58.7	61.1	58.8	64.9	67.5	71.1
Aviation Gasoline	3.1	2.7	2.5	2.4	2.3	2.1	2.2	2.4	2.3
General Aviation Aircraft	3.1	2.7	2.5	2.4	2.3	2.1	2.2	2.4	2.3
Residual Fuel Oil	80.1	71.7	69.9	46.1	53.3	45.0	58.3	66.0	64.9
Ships and Other Boats[c]	23.7	30.5	34.9	12.6	30.5	7.8	14.7	20.2	17.7
Ships (Bunkers)[c]	56.4	41.2	35.0	33.6	22.8	37.2	43.6	45.8	47.2
Natural Gas	**36.1**	**38.4**	**35.7**	**34.1**	**37.2**	**33.4**	**32.0**	**33.2**	**33.2**
Passenger Cars	+	0.1	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+	+	+
Buses	+	0.1	0.4	0.5	0.6	0.7	0.8	0.8	0.8
Pipeline	36.1	38.2	35.2	33.6	36.6	32.7	31.2	32.3	32.4
LPG	1.4	1.1	0.7	0.8	0.8	1.0	1.1	1.1	1.1
Light-Duty Trucks	0.5	0.5	0.3	0.3	0.3	0.4	0.4	0.4	0.4
Medium- and Heavy-Duty Trucks[b]	0.8	0.5	0.4	0.5	0.5	0.6	0.7	0.6	0.6
Buses	+	+	+	+	+	+	+	+	+
Electricity	**3.0**	**3.0**	**3.4**	**3.6**	**3.4**	**4.2**	**4.5**	**4.7**	**4.9**
Rail	3.0	3.0	3.4	3.6	3.4	4.2	4.5	4.7	4.9
Total (Including Bunkers)[d]	**1,601.8**	**1,703.1**	**1,902.7**	**1,876.8**	**1,921.4**	**1,915.4**	**1,979.8**	**1,997.1**	**1,988.1**
Total (Excluding Bunkers)[d]	**1,488.1**	**1,602.5**	**1,801.6**	**1,779.2**	**1,832.3**	**1,811.8**	**1,860.9**	**1,874.5**	**1,861.0**

Note: Totals may not sum due to independent rounding. Emissions estimates for passenger cars, light-duty trucks and heavy-duty trucks are calculated using fuel consumption data from FHWA's *Highway Statistics*, which used an updated methodology to develop the 2005 and 2006 estimates This causes some discontinuity in the emissions estimates for gasoline and diesel on-road vehicles between 2004 and 2005.

[a] This table does not include emissions from non-transportation mobile sources, such as agricultural equipment and

construction/mining equipment; it also does not include emissions associated with electricity consumption by pipelines or lubricants used in transportation.
[b] Includes medium- and heavy-duty trucks over 8,500 lbs.
[c] Fluctuations in emission estimates from the combustion of residual fuel oil are associated with fluctuations in reported fuel consumption and may reflect data collection problems.
[d] Official estimates exclude emissions from the combustion of both aviation and marine international bunker fuels; however, estimates including international bunker fuel-related emissions are presented for informational purposes.
+ Less than 0.05 Tg CO_2 Eq.

Industrial End-Use Sector

The industrial end-use sector accounted for 28 percent of CO_2 emissions from fossil fuel combustion. On average, 55 percent of these emissions resulted from the direct consumption of fossil fuels for steam and process heat production. The remaining 45 percent was associated with their consumption of electricity for uses such as motors, electric furnaces, ovens, and lighting.

The industrial end-use sector, per the underlying energy consumption data from EIA, includes activities such as manufacturing, construction, mining, and agriculture. The largest of these activities in terms of energy consumption is manufacturing, of which six industries—Petroleum Refineries, Chemicals, Primary Metals, Paper, Food, and Nonmetallic Mineral Products—represent the vast majority of the energy use (EIA 2007a and EIA 2005).

In theory, emissions from the industrial end-use sector should be highly correlated with economic growth and industrial output, but heating of industrial buildings and agricultural energy consumption are also affected by weather conditions.[10] In addition, structural changes within the U.S. economy that lead to shifts in industrial output away from energy intensive manufacturing products to less energy intensive products (e.g., from steel to computer equipment) also have a significant affect on industrial emissions.

From 2005 to 2006, total industrial production and manufacturing output increased by 3.9 and 4.9 percent, respectively (FRB 2006). Over this period, output increased for Petroleum Refineries, Chemicals, Primary Metals, Food, and Nonmetallic Mineral Products, but decreased slightly for Paper (see Figure 3-12).

Figure 3-12: Industrial Production Indices (Index 2002=100)

Despite the growth in industrial output (62 percent) and the overall U.S. economy (59 percent) from 1990 to 2006, CO_2 emissions from the industrial end-use sector increased by only 3.0 percent over that time. A number of factors are believed to have caused this disparity between rapid growth in industrial output and decrease in industrial emissions, including: (1) more rapid growth in output from less energy-intensive industries relative to traditional manufacturing industries, and (2) improvements in energy efficiency. In 2006, CO_2 emissions from fossil fuel combustion and electricity use within the industrial end-use sectors were 1,571.0 Tg CO_2 Eq., or 0.8 percent below 2005 emissions.

Residential and Commercial End-Use Sectors

The residential and commercial end-use sectors accounted for an average 20 and 18 percent, respectively, of CO_2 emissions from fossil fuel combustion. Both end-use sectors were heavily reliant on electricity for meeting energy

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[10] Some commercial customers are large enough to obtain an industrial price for natural gas and/or electricity and are consequently grouped with the industrial end-use sector in U.S. energy statistics. These misclassifications of large commercial customers likely cause the industrial end-use sector to appear to be more sensitive to weather conditions.

needs, with electricity consumption for lighting, heating, air conditioning, and operating appliances contributing to about 72 and 79 percent of emissions from the residential and commercial end-use sectors, respectively. The remaining emissions were largely due to the direct consumption of natural gas and petroleum products, primarily for heating and cooking needs. Coal consumption was a minor component of energy use in both of these end-use sectors. In 2006, CO_2 emissions from fossil fuel combustion and electricity use within the residential and commercial end-use sectors were 1,151.9 Tg CO_2 Eq. and 1,003.0 Tg CO_2 Eq., respectively.

Emissions from the residential and commercial sectors have generally been increasing since 1990, and are often correlated with short-term fluctuations in energy consumption caused by weather conditions, rather than prevailing economic conditions (see Table 3-6). In the long-term, both end-use sectors are also affected by population growth, regional migration trends, and changes in housing and building attributes (e.g., size and insulation).

Emissions from natural gas consumption represent over 72 and 73 percent of the direct (not including electricity) fossil fuel emissions from the residential and commercial sectors, respectively. In 2006, natural gas emissions decreased by 10 percent and 6 percent, respectively, in each of these sectors. The decrease in emissions in both sectors is a result of warmer conditions in the United States.

Electricity sales to the residential and commercial end-use sectors in 2006 decreased less than 1 percent in the residential sector and increased by 2 percent in the commercial sector. The trend in the commercial sector can largely be attributed to the growing economy (2.9 percent), which led to increased demand for electricity. Increased consumption due to the growing economy was somewhat offset by decreased air conditioning-related electricity consumption in the residential sector with the cooler summer compared to 2005, and increases in electricity prices. Electricity-related emissions in both the residential and commercial sectors decreased due to decreased consumption; total emissions from the residential sector decreased by 8.9 percent in 2006, with emissions from the commercial sector 5.3 percent lower than in 2005.

Electricity Generation

The process of generating electricity is the single largest source of CO_2 emissions in the United States, representing 39 percent of total CO_2 emissions from all CO_2 emissions sources across the United States. Electricity generation also accounted for the largest share of CO_2 emissions from fossil fuel combustion, approximately 41 percent in 2006. Electricity was consumed primarily in the residential, commercial, and industrial end-use sectors for lighting, heating, electric motors, appliances, electronics, and air conditioning (see Figure 3-13).

Figure 3-13: Electricity Generation Retail Sales by End-Use Sector

The electric power industry includes all power producers, consisting of both regulated utilities and nonutilities (e.g. independent power producers, qualifying cogenerators, and other small power producers). For the underlying energy data used in this chapter, the Energy Information Administration (EIA) categorizes electric power generation into three functional categories: the electric power sector, the commercial sector, and the industrial sector. The electric power sector consists of electric utilities and independent power producers whose primary business is the production of electricity,[11] while the other sectors consist of those producers that indicate their primary business is other than the production of electricity.

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[11] Utilities primarily generate power for the U.S. electric grid for sale to retail customers. Nonutilities produce electricity for their own use, to sell to large consumers, or to sell on the wholesale electricity market (e.g., to utilities for distribution and resale to customers).

In 2006, the amount of electricity generated (in kWh) increased by 0.1 percent. This growth is due to the growing economy, expanding industrial production, and warmer summer conditions. However, CO_2 emissions decreased by 2.2 percent, as a smaller share of electricity was generated by coal and a greater share generated by natural gas. Coal and natural gas consumption for electricity generation decreased by 1.3 percent and increased by 6.4 percent, respectively, in 2006, and nuclear power increased by less than 1 percent. As a result of the decrease in coal consumption, C intensity from direct fossil fuel combustion decreased slightly overall in 2006 (see Table 3-8). Coal is consumed primarily by the electric power sector in the United States, which accounted for 94 percent of total coal consumption for energy purposes in 2006. The amount of electricity generated from renewables increased by 8.1 percent in 2006.

Methodology

The methodology used by the United States for estimating CO_2 emissions from fossil fuel combustion is conceptually similar to the approach recommended by the IPCC for countries that intend to develop detailed, sectoral-based emission estimates (IPCC 2006). A detailed description of the U.S. methodology is presented in Annex 2.1, and is characterized by the following steps:

1. *Determine total fuel consumption by fuel type and sector.* Total fossil fuel consumption for each year is estimated by aggregating consumption data by end-use sector (e.g., commercial, industrial, etc.), primary fuel type (e.g., coal, petroleum, gas), and secondary fuel category (e.g., motor gasoline, distillate fuel oil, etc.). Fuel consumption data for the United States were obtained directly from the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE), primarily from the *Monthly Energy Review* and published supplemental tables on petroleum product detail (EIA 2007b). The United States does not include territories in its national energy statistics, so fuel consumption data for territories were collected separately from Grillot (2007).[12]

   For consistency of reporting, the IPCC has recommended that countries report energy data using the International Energy Agency (IEA) reporting convention and/or IEA data. Data in the IEA format are presented "top down"—that is, energy consumption for fuel types and categories are estimated from energy production data (accounting for imports, exports, stock changes, and losses). The resulting quantities are referred to as "apparent consumption." The data collected in the United States by EIA, and used in this inventory, are, instead, "bottom up" in nature. In other words, they are collected through surveys at the point of delivery or use and aggregated to determine national totals.[13]

   It is also important to note that U.S. fossil fuel energy statistics are generally presented using gross calorific values (GCV) (i.e., higher heating values). Fuel consumption activity data presented here have not been adjusted to correspond to international standard, which are to report energy statistics in terms of net calorific values (NCV) (i.e., lower heating values).[14]

2. *Subtract uses accounted for in the Industrial Processes chapter.* Portions of the fuel consumption data for six fuel categories—coking coal, industrial other coal, petroleum coke, natural gas, residual fuel oil, and other oil—were reallocated to the industrial processes chapter, as they were consumed during non-energy related industrial activity. To make these adjustments, additional data were collected from AISI (1995 through 2007), Gambogi (2007), Coffeyville Resources Nitrogen Fertilizers, LLC (2007), Corathers (2007), U.S. Census Bureau (2007), EIA (2007h), EIA (2001), Smith, G. (2007), USGS (1998 through 2002), USGS (1995), USGS

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[12] Fuel consumption by U.S. territories (i.e., American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands) is included in this report and contributed emissions of 55 Tg CO_2 Eq. in 2006.

[13] See IPCC Reference Approach for estimating CO_2 emissions from fossil fuel combustion in Annex 4 for a comparison of U.S. estimates using top-down and bottom-up approaches.

[14] A crude convention to convert between gross and net calorific values is to multiply the heat content of solid and liquid fossil fuels by 0.95 and gaseous fuels by 0.9 to account for the water content of the fuels. Biomass-based fuels in U.S. energy statistics, however, are generally presented using net calorific values.

(1991a through 2006a), USGS (1991b through 2006b), USGS (1991 through 2005), and USGS (1995 through 2006).[15]

3. *Adjust for biofuels, conversion of fossil fuels, and exports of CO_2.* Fossil fuel consumption estimates are adjusted downward to exclude (1) fuels with biogenic origins, (2) fuels created from other fossil fuels, and (3) exports of CO_2. Fuels with biogenic origins are assumed to result in no net CO_2 emissions, and must be subtracted from fuel consumption estimates. These fuels include ethanol added to motor gasoline and biomass gas used as natural gas. Synthetic natural gas is created from industrial coal, and is currently included in EIA statistics for both coal and natural gas. Therefore, synthetic natural gas is subtracted from energy consumption statistics.[16] Since October 2000, the Dakota Gasification Plant has been exporting CO_2 to Canada by pipeline. Since this CO_2 is not emitted to the atmosphere in the United States, energy used to produce this CO_2 is subtracted from energy consumption statistics. To make these adjustments, additional data for ethanol and biogas were collected from EIA (2007b) and data for synthetic natural gas were collected from EIA (2007e), and data for CO_2 exports were collected from the Dakota Gasification Company (2006), Fitzpatrick (2002), Erickson (2003), EIA (2006), and EIA (2007e).

4. *Adjust Sectoral Allocation of Distillate Fuel Oil and Motor Gasoline.* EPA had conducted a separate bottom-up analysis of transportation fuel consumption based on FHWA Vehicle Miles Traveled (VMT) that indicated that the amount of distillate and motor gasoline consumption allocated to the transportation sector in the EIA statistics should be adjusted. Therefore, for these estimates, the transportation sector's distillate fuel and motor gasoline consumption was adjusted higher to match the value obtained from the bottom-up analysis based on VMT. As the total distillate consumption estimate from EIA is considered to be accurate at the national level, the distillate consumption totals for the residential, commercial, and industrial sectors were adjusted downward proportionately. Similarly, as the total motor gasoline consumption estimate is considered to be accurate at the national level, the motor gasoline consumption totals for commercial and industrial sectors were adjusted downward proportionately. The data sources used in the bottom-up analysis of transportation fuel consumption include AAR (2007), Benson (2002 through 2004), DOE (1993 through 2005), EIA (2007a), EIA (1991 through 2005), EPA (2004), and FHWA (1996 through 2006).

5. *Adjust for fuels consumed for non-energy uses.* U.S. aggregate energy statistics include consumption of fossil fuels for non-energy purposes. Depending on the end-use, this can result in storage of some or all of the C contained in the fuel for a period of time. As the emission pathways of C used for non-energy purposes are vastly different than fuel combustion, these emissions are estimated separately in the Carbon Emitted and Stored in Products from Non-Energy Uses of Fossil Fuels section in this chapter. Therefore, the amount of fuels used for non-energy purposes was subtracted from total fuel consumption. Data on non-fuel consumption was provided by EIA (2007b).

6. *Subtract consumption of international bunker fuels.* According to the UNFCCC reporting guidelines emissions from international transport activities, or bunker fuels, should not be included in national totals. U.S. energy consumption statistics include these bunker fuels (e.g., distillate fuel oil, residual fuel oil, and jet fuel) as part of consumption by the transportation end-use sector, however, so emissions from international transport activities were calculated separately following the same procedures used for emissions from consumption of all fossil fuels (i.e., estimation of consumption, and determination of C content).[17] The Office of the Under Secretary of Defense (Installations and Environment) and the Defense Energy Support Center (Defense Logistics Agency) of the U.S. Department of Defense (DoD) (DESC 2007) supplied data on military jet fuel and marine fuel use. Commercial jet fuel use was obtained from BEA (1991 through 2007) and DOT (1991 through 2007); residual and distillate fuel use for civilian marine bunkers was obtained from DOC (1991 through 2007) for 1990 through 2002, and DHS (2008) for 2003 through 2008. Consumption of these fuels was subtracted from the

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[15] See sections on Iron and Steel Production, Ammonia Manufacture, Petrochemical Production, Titanium Dioxide Production, Ferroalloy Production, Aluminum Production, and Silicon Carbide Production in the Industrial Processes chapter.

[16] These adjustments are explained in greater detail in Annex 2.1.

[17] See International Bunker Fuels section in this chapter for a more detailed discussion.

corresponding fuels in the transportation end-use sector. Estimates of international bunker fuel emissions are discussed further in the section entitled International Bunker Fuels.

7. *Determine the total C content of fuels consumed*. Total C was estimated by multiplying the amount of fuel consumed by the amount of C in each fuel. This total C estimate defines the maximum amount of C that could potentially be released to the atmosphere if all of the C in each fuel was converted to CO_2. The C content coefficients used by the United States were obtained from EIA's *Emissions of Greenhouse Gases in the United States 2006* (EIA 2007c) and EIA's *Monthly Energy Review* and published supplemental tables on petroleum product detail EIA (EIA 2007b). They are presented in Annexes 2.1 and 2.2.

8. *Estimate CO_2 Emissions*. Total CO_2 emissions are the product of the adjusted energy consumption (from the previous methodology steps 1 through 6), the C content of the fuels consumed, and the fraction of C that is oxidized. The fraction oxidized was assumed to be 100 percent for petroleum, coal, and natural gas based on guidance in IPCC (2006) (see Annex 2.1).

9. *Allocate transportation emissions by vehicle type*. This report provides a more detailed accounting of emissions from transportation because it is such a large consumer of fossil fuels in the United States. For fuel types other than jet fuel, fuel consumption data by vehicle type and transportation mode were used to allocate emissions by fuel type calculated for the transportation end-use sector.

- For on-road vehicles, annual estimates of combined motor gasoline and diesel fuel consumption by vehicle category were obtained from FHWA (1996 through 2006); for each vehicle category, the percent gasoline, diesel, and other (e.g., CNG, LPG) fuel consumption are estimated using data from DOE (1993 through 2005).

- For non-road vehicles, activity data were obtained from AAR (2007), APTA (2007 and 2006), BEA (1991 through 2007), Benson (2002 through 2004), DOE (1993 through 2005), DESC (2007), DOC (1991 through 2007), DOT (1991 through 2007), EIA (2007a), EIA (2007d), EIA (2007g), EIA (2002), EIA (1991 through 2005), EPA (2004), FAA (2005), and Gaffney (2007).

- For jet fuel used by aircraft, CO_2 emissions were calculated directly based on reported consumption of fuel as reported by EIA, and allocated to commercial aircraft using flight-specific fuel consumption data from the Federal Aviation Administration's (FAA) System for assessing Aviation's Global Emission (SAGE) model.[18] Allocation to domestic general aviation was made using FAA Aerospace Forecast data, and allocation to domestic military uses was made using DoD data (see Annex 3.7).

Heat contents and densities were obtained from EIA (2007a) and USAF (1998).[19]

[BEGIN BOX]

Box 3-2: Carbon Intensity of U.S. Energy Consumption

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[18] FAA's System for assessing Aviation's Global Emissions (SAGE) model develops aircraft fuel burn and emissions for all commercial flights globally in a given year. The SAGE model dynamically models aircraft performance, fuel burn, and emissions, and is based on actual flight-by-flight aircraft movements. See <http://www.faa.gov/about/office_org/headquarters_offices/aep/models/sage/>.

[19] For a more detailed description of the data sources used for the analysis of the transportation end use sector see the Mobile Combustion (excluding CO_2) and International Bunker Fuels sections of the Energy chapter, Annex 3.2, and Annex 3.7.

Fossil fuels are the dominant source of energy in the United States, and CO_2 is emitted as a product from their combustion. Useful energy, however, is generated in the United States from many other sources that do not emit CO_2 in the energy conversion process, such as renewable (i.e., hydropower, biofuels, geothermal, solar, and wind) and nuclear sources.[20]

Energy-related CO_2 emissions can be reduced by not only lowering total energy consumption (e.g., through conservation measures) but also by lowering the C intensity of the energy sources employed (e.g., fuel switching from coal to natural gas). The amount of C emitted from the combustion of fossil fuels is dependent upon the C content of the fuel and the fraction of that C that is oxidized. Fossil fuels vary in their average C content, ranging from about 53 Tg CO_2 Eq./QBtu for natural gas to upwards of 95 Tg CO_2 Eq./QBtu for coal and petroleum coke.[21] In general, the C content per unit of energy of fossil fuels is the highest for coal products, followed by petroleum, and then natural gas. Other sources of energy, however, may be directly or indirectly C neutral (i.e., 0 Tg CO_2 Eq./Btu). Energy generated from nuclear and many renewable sources do not result in direct emissions of CO_2. Biofuels such as wood and ethanol are also considered to be C neutral; although these fuels do emit CO_2, in the long run the CO_2 emitted from biomass consumption does not increase atmospheric CO_2 concentrations if the biogenic C emitted is offset by the growth of new biomass.[22] The overall C intensity of the U.S. economy is thus dependent upon the quantity and combination of fuels and other energy sources employed to meet demand.

Table 3-8 provides a time series of the C intensity for each sector of the U.S. economy. The time series incorporates only the energy consumed from the direct combustion of fossil fuels in each sector. For example, the C intensity for the residential sector does not include the energy from or emissions related to the consumption of electricity for lighting or wood for heat. Looking only at this direct consumption of fossil fuels, the residential sector exhibited the lowest C intensity, which is related to the large percentage of its energy derived from natural gas for heating. The C intensity of the commercial sector has predominantly declined since 1990 as commercial businesses shift away from petroleum to natural gas. The industrial sector was more dependent on petroleum and coal than either the residential or commercial sectors, and thus had higher C intensities over this period. The C intensity of the transportation sector was closely related to the C content of petroleum products (e.g., motor gasoline and jet fuel, both around 70 Tg CO_2 Eq./EJ), which were the primary sources of energy. Lastly, the electricity generation sector had the highest C intensity due to its heavy reliance on coal for generating electricity.

Table 3-8: Carbon Intensity from Direct Fossil Fuel Combustion by Sector (Tg CO_2 Eq./QBtu)

Sector	1990		1995		2000	2001	2002	2003	2004	2005	2006
Residential [a]	57.3		56.6		56.7	56.9	56.6	56.8	56.9	56.6	56.7
Commercial [a]	59.2		57.8		57.1	57.4	57.0	57.3	57.6	57.6	57.5
Industrial [a]	63.7		62.7		62.6	63.5	62.8	63.2	63.6	64.0	64.2
Transportation [a]	71.0		71.0		71.0	71.0	71.0	71.0	71.0	71.1	71.1
Electricity Generation [b]	86.7		86.0		85.6	85.2	85.0	85.7	85.4	85.0	84.6
U.S. Territories [c]	74.1		74.1		73.2	73.6	73.7	74.0	74.6	74.6	74.6
All Sectors [c]	**72.7**		**72.2**		**72.7**	**72.7**	**72.5**	**72.7**	**72.9**	**73.1**	**73.0**

[a] Does not include electricity or renewable energy consumption.
[b] Does not include electricity produced using nuclear or renewable energy.
[c] Does not include nuclear or renewable energy consumption.
Note: Excludes non-energy fuel use emissions and consumption.

[20] Small quantities of CO_2, however, are released from some geologic formations tapped for geothermal energy. These emissions are included with fossil fuel combustion emissions from the electricity generation. Carbon dioxide emissions may also be generated from upstream activities (e.g., manufacture of the equipment) associated with fossil fuel and renewable energy activities, but are not accounted for here.

[21] One exajoule (EJ) is equal to 10^{18} joules or 0.9478 QBtu.

[22] Net carbon fluxes from changes in biogenic carbon reservoirs in wooded or croplands are accounted for in the estimates for Land Use, Land-Use Change, and Forestry.

In contrast to Table 3-8, Table 3-9 presents C intensity values that incorporate energy consumed from all sources (i.e., fossil fuels, renewables, and nuclear). In addition, the emissions related to the generation of electricity have been attributed to both electricity generation and the end-use sectors in which that electricity was eventually consumed.[23] This table, therefore, provides a more complete picture of the actual C intensity of each end-use sector per unit of energy consumed. The transportation end-use sector in Table 3-9 emerges as the most C intensive when all sources of energy are included, due to its almost complete reliance on petroleum products and relatively minor amount of biomass-based fuels used, such as ethanol. The "other end-use sectors" (i.e., residential, commercial, and industrial) use significant quantities of biofuels such as wood, thereby lowering the overall C intensity. The C intensity of the electricity generation sector differs greatly from the scenario in Table 3-8, where only the energy consumed from the direct combustion of fossil fuels was included. This difference is due almost entirely to the inclusion of electricity generation from nuclear and hydropower sources, which do not emit CO_2.

Table 3-9: Carbon Intensity from all Energy Consumption by Sector (Tg CO_2 Eq./QBtu)

Sector	1990		1995		2000	2001	2002	2003	2004	2005	2006
Transportation [a]	70.8		70.6		70.6	70.5	70.5	70.3	70.2	70.1	70.0
Other End-Use Sectors [a, b]	57.5		56.4		57.7	58.4	57.6	58.0	58.0	58.2	57.5
Electricity Generation [c]	59.0		57.9		59.9	60.2	59.2	59.8	59.6	59.9	58.8
All Sectors [d]	**61.1**		**60.3**		**61.4**	**61.8**	**61.3**	**61.5**	**61.5**	**61.6**	**61.1**

[a] Includes electricity (from fossil fuel, nuclear, and renewable sources) and direct renewable energy consumption.
[b] Other End-Use Sectors includes the residential, commercial, and industrial sectors.
[c] Includes electricity generation from nuclear and renewable sources.
[d] Includes nuclear and renewable energy consumption.
Note: Excludes non-energy fuel use emissions and consumption.

By comparing the values in Table 3-8 and Table 3-9, a few observations can be made. The use of renewable and nuclear energy sources has resulted in a significantly lower C intensity of the U.S. economy. Over the sixteen-year period of 1990 through 2006, however, the C intensity of U.S. energy consumption has been fairly constant, as the proportion of renewable and nuclear energy technologies have not changed significantly. Per capita energy consumption has fluctuated, but is now roughly equivalent to levels in 1990 (see Figure 3-14). Due to a general shift from a manufacturing-based economy to a service-based economy, as well as overall increases in efficiency, energy consumption and energy-related CO_2 emissions per dollar of gross domestic product (GDP) have both declined since 1990 (BEA 2007).

Figure 3-14: U.S. Energy Consumption and Energy-Related CO_2 Emissions Per Capita and Per Dollar GDP

C intensity estimates were developed using nuclear and renewable energy data from EIA (2007a) and fossil fuel consumption data as discussed above and presented in Annex 2.1.

[END BOX]

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[23] In other words, the emissions from the generation of electricity are intentionally double counted by attributing them both to electricity generation and the end-use sector in which electricity consumption occurred.

Uncertainty

For estimates of CO_2 from fossil fuel combustion, the amount of CO_2 emitted is directly related to the amount of fuel consumed, the fraction of the fuel that is oxidized, and the carbon content of the fuel. Therefore, a careful accounting of fossil fuel consumption by fuel type, average carbon contents of fossil fuels consumed, and production of fossil fuel-based products with long-term carbon storage should yield an accurate estimate of CO_2 emissions.

Nevertheless, there are uncertainties in the consumption data, carbon content of fuels and products, and carbon oxidation efficiencies. For example, given the same primary fuel type (e.g., coal, petroleum, or natural gas), the amount of carbon contained in the fuel per unit of useful energy can vary. For the United States, however, the impact of these uncertainties on overall CO_2 emission estimates is believed to be relatively small. See, for example, Marland and Pippin (1990).

Although statistics of total fossil fuel and other energy consumption are relatively accurate, the allocation of this consumption to individual end-use sectors (i.e., residential, commercial, industrial, and transportation) is less certain. For example, for some fuels the sectoral allocations are based on price rates (i.e., tariffs), but a commercial establishment may be able to negotiate an industrial rate or a small industrial establishment may end up paying an industrial rate, leading to a misallocation of emissions. Also, the deregulation of the natural gas industry and the more recent deregulation of the electric power industry have likely led to some minor problems in collecting accurate energy statistics as firms in these industries have undergone significant restructuring.

To calculate the total CO_2 emission estimate from energy-related fossil fuel combustion, the amount of fuel used in these non-energy production processes were subtracted from the total fossil fuel consumption for 2006. The amount of CO_2 emissions resulting from non-energy related fossil fuel use has been calculated separately and reported in the Carbon Emitted from Non-Energy Uses of Fossil Fuels section of this report. These factors all contribute to the uncertainty in the CO_2 estimates. Detailed discussions on the uncertainties associated with C emitted from Non-Energy Uses of Fossil Fuels can be found within that section of this chapter.

Various sources of uncertainty surround the estimation of emissions from international bunker fuels, which are subtracted from the U.S. totals (see the detailed discussions on these uncertainties provided in the International Bunker Fuels section of this chapter). Another source of uncertainty is fuel consumption by U.S. territories. The United States does not collect energy statistics for its territories at the same level of detail as for the fifty states and the District of Columbia. Therefore, estimating both emissions and bunker fuel consumption by these territories is difficult.

Uncertainties in the emission estimates presented above also result from the data used to allocate CO_2 emissions from the transportation end-use sector to individual vehicle types and transport modes. In many cases, bottom-up estimates of fuel consumption by vehicle type do not match aggregate fuel-type estimates from EIA. Further research is planned to improve the allocation into detailed transportation end-use sector emissions. In particular, residual fuel consumption data for marine vessels are highly uncertain, as shown by the large fluctuations in emissions that do not mimic changes in other variables such as shipping ton miles.

The uncertainty analysis was performed by primary fuel type for each end-use sector, using the IPCC-recommended Tier 2 uncertainty estimation methodology, Monte Carlo Simulation technique, with @RISK software. For this uncertainty estimation, the inventory estimation model for CO_2 from fossil fuel combustion was integrated with the relevant inventory variables from the inventory estimation model for International Bunker Fuels, to realistically characterize the interaction (or endogenous correlation) between the variables of these two models. About 150 input variables were modeled for CO_2 from energy-related Fossil Fuel Combustion (including about 10 for non-energy fuel consumption and about 20 for International Bunker Fuels).

In developing the uncertainty estimation model, uniform distributions were assumed for all activity-related input variables and emission factors, based on the SAIC/EIA (2001) report.[24] Triangular distributions were assigned for the oxidization factors (or combustion efficiencies). The uncertainty ranges were assigned to the input variables based on the data reported in SAIC/EIA (2001) and on conversations with various agency-personnel.[25]

The uncertainty ranges for the activity-related input variables were typically asymmetric around their inventory estimates; the uncertainty ranges for the emissions factors were symmetric. Bias (or systematic uncertainties) associated with these variables accounted for much of the uncertainties associated with these variables (SAIC/EIA 2001).[26] For purposes of this uncertainty analysis, each input variable was simulated 10,000 times through Monte Carlo Sampling.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-10. Fossil fuel combustion CO_2 emissions in 2006 were estimated to be between 5,542.9 and 5,944.7 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 2 percent below to 5 percent above the 2006 emission estimate of 5,637.9 Tg CO_2 Eq.

Table 3-10: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Energy-related Fossil Fuel Combustion by Fuel Type and Sector (Tg CO_2 Eq. and Percent)

Fuel/Sector	2006 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a]			
		(Tg CO_2 Eq.)		(%)	
		Lower Bound	Upper Bound	Lower Bound	Upper Bound
Coal [b]	**2,065.3**	**1,996.8**	**2,262.1**	**-3%**	**+10%**
Residential	0.6	0.5	0.7	-6%	+15%
Commercial	6.2	5.9	7.1	-5%	+15%
Industrial	122.0	117.3	142.4	-4%	+17%
Transportation	NE	NE	NE	NA	NA
Electricity Generation	1,932.4	1,856.4	2,119.9	-4%	+10%
U.S. Territories	4.1	3.6	4.9	-12%	+19%
Natural Gas [b]	**1,155.1**	**1,164.8**	**1,231.2**	**+1%**	**+7%**
Residential	237.5	230.8	254.2	-3%	+7%
Commercial	154.1	149.7	164.9	-3%	+7%
Industrial	389.3	399.5	440.0	+3%	+13%
Transportation	33.2	32.3	35.5	-3%	+7%
Electricity Generation	339.6	329.6	356.9	-3%	+5%
U.S. Territories	1.4	1.2	1.6	-12%	+17%
Petroleum [b]	**2,417.1**	**2,282.9**	**2,554.7**	**-6%**	**+6%**
Residential	88.5	83.8	92.8	-5%	+5%

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[24] SAIC/EIA (2001) characterizes the underlying probability density function for the input variables as a combination of uniform and normal distributions (the former to represent the bias component and the latter to represent the random component). However, for purposes of the current uncertainty analysis, it was determined that uniform distribution was more appropriate to characterize the probability density function underlying each of these variables.

[25] In the SAIC/EIA (2001) report, the quantitative uncertainty estimates were developed for each of the three major fossil fuels used within each end-use sector; the variations within the sub-fuel types within each end-use sector were not modeled. However, for purposes of assigning uncertainty estimates to the sub-fuel type categories within each end-use sector in the current uncertainty analysis, SAIC/EIA (2001)-reported uncertainty estimates were extrapolated.

[26] Although, in general, random uncertainties are the main focus of statistical uncertainty analysis, when the uncertainty estimates are elicited from experts, their estimates include both random and systematic uncertainties. Hence, both these types of uncertainties are represented in this uncertainty analysis.

Commercial	49.8	47.5	51.8	-5%	+4%
Industrial	350.9	305.2	407.1	-13%	+16%
Transportation	1,822.8	1,700.5	1,940.0	-7%	+6%
Electric Utilities	55.7	53.3	59.7	-4%	+7%
U.S. Territories	**49.4**	**45.6**	**54.9**	**-8%**	**+11%**
Total (excluding Geothermal) [b]	**5,637.6**	**5,542.5**	**5,944.3**	**-2%**	**+5%**
Geothermal	0.4	NE	NE	NE	NE
Total (including Geothermal) [b,c]	**5,637.9**	**5,542.9**	**5,944.7**	**-2%**	**+5%**

NA (Not Applicable)
NE (Not Estimated)
[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.
[b] The low and high estimates for total emissions were calculated separately through simulations and, hence, the low and high emission estimates for the sub-source categories do not sum to total emissions.
[c] Geothermal emissions added for reporting purposes, but an uncertainty analysis was not performed for CO_2 emissions from geothermal production.

QA/QC and Verification

A source-specific QA/QC plan for CO_2 from fossil fuel combustion was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and methodology used for estimating CO_2 emissions from fossil fuel combustion in the United States. Emission totals for the different sectors and fuels were compared and trends were investigated to determine whether any corrective actions were needed. Minor corrective actions were taken.

Recalculations Discussion

The Energy Information Administration (EIA 2007b) updated energy consumption data for all years. These revisions primarily impacted the emission estimates for 2005. Overall, these changes resulted in an average annual increase of 0.8 Tg CO_2 Eq. (less than 0.1 percent) in CO_2 emissions from fossil fuel combustion for the period 1990 through 2005.

Planned Improvements

To reduce uncertainty of CO_2 from fossil fuel combustion estimates, efforts will be taken to work with EIA and other agencies to improve the quality of the U.S. territories data. This improvement is not all-inclusive, and is part of an ongoing analysis and efforts to continually improve the CO_2 from fossil fuel combustion estimates. In addition, further expert ilicitation may be conducted to better quantify the total uncertainty associated with emissions from this source.

3.2. Carbon Emitted from Non-Energy Uses of Fossil Fuels (IPCC Source Category 1A)

In addition to being combusted for energy, fossil fuels are also consumed for non-energy uses (NEU) in the United States. The fuels used for these purposes are diverse, including natural gas, liquefied petroleum gases (LPG), asphalt (a viscous liquid mixture of heavy crude oil distillates), petroleum coke (manufactured from heavy oil), and coal coke (manufactured from coking coal). The non-energy applications are equally diverse, and include feedstocks for the manufacture of plastics, rubber, synthetic fibers and other materials; reducing agents for the production of various metals and inorganic products; and non-energy products such as lubricants, waxes, and asphalt (IPCC 2006).

CO_2 emissions arise from non-energy uses via several pathways. Emissions may occur during the manufacture of a

product, as is the case in producing plastics or rubber from fuel-derived feedstocks. Additionally, emissions may occur during the product's lifetime, such as during solvent use. Overall, throughout the time series and across all uses, about 62 percent of the total C consumed for non-energy purposes was stored in products, and not released to the atmosphere; the remaining 38 percent was emitted.

There are several areas in which non-energy uses of fossil fuels are closely related to other parts of the inventory. For example, some of the NEU products release CO_2 at the end of their commercial life when they are combusted after disposal; these emissions are reported separately within the Energy chapter in the Municipal Solid Waste Combustion source category. In addition, there is some overlap between fossil fuels consumed for non-energy uses and the fossil-derived CO_2 emissions accounted for in the Industrial Processes chapter, especially for fuels used as reducing agents. To avoid double-counting, the "raw" non-energy fuel consumption data reported by EIA are modified to account for these overlaps. There are also net exports of petrochemicals that are not completely accounted for in the EIA data, and these affect the mass of C in non-energy applications.

As shown in Table 3-11, fossil fuel emissions in 2006 from the non-energy uses of fossil fuels were 138.0 Tg CO_2 Eq., which constituted approximately 2 percent of overall fossil fuel emissions, approximately the same proportion as in 1990. In 2006, the consumption of fuels for non-energy uses (after the adjustments described above) was 5,417.8 TBtu, an increase of 21 percent since 1990 (see Table 3-12). About 65.4 Tg of the C (239.6 Tg CO_2 Eq.) in these fuels was stored, while the remaining 37.6 Tg C (138.0 Tg CO_2 Eq.) was emitted. The proportion of C emitted as CO_2 has remained about constant since 1990, at about 36 to 40 percent of total non-energy consumption (see Table 3-11).

Table 3-11: CO_2 Emissions from Non-Energy Use Fossil Fuel Consumption (Tg CO_2 Eq.)

Year	1990		1995		2000	2001	2002	2003	2004	2005	2006
Potential Emissions	312.6		346.8		385.5	364.8	368.4	356.3	394.9	382.2	377.6
C Stored	195.5		213.5		244.1	232.9	232.6	224.5	246.0	243.1	239.6
Emissions as a % of Potential	37%		38%		37%	36%	37%	37%	38%	36%	37%
Emissions	**117.2**		**133.2**		**141.4**	**131.9**	**135.9**	**131.8**	**148.9**	**139.1**	**138.0**

Methodology

The first step in estimating C stored in products was to determine the aggregate quantity of fossil fuels consumed for non-energy uses. The C content of these feedstock fuels is equivalent to potential emissions, or the product of consumption and the fuel-specific C content values. Both the non-energy fuel consumption and C content data were supplied by the EIA (2007) (see Annex 2.1). Consumption of natural gas, LPG, pentanes plus, naphthas, other oils, and special naphtha were adjusted to account for net exports of these products that are not reflected in the raw data from EIA. Consumption values for industrial coking coal, petroleum coke, other oils, and natural gas in Table 3-12 and Table 3-13 have been adjusted to subtract non-energy uses that are included in the source categories of the Industrial Processes chapter.[27] Consumption values were also adjusted to subtract exports of intermediary chemicals.

For the remaining non-energy uses, the quantity of C stored was estimated by multiplying the potential emissions by a storage factor. For several fuel types—petrochemical feedstocks (including natural gas for non-fertilizer uses, LPG, pentanes plus, naphthas, other oils, still gas, special naphtha, and industrial other coal), asphalt and road oil, lubricants, and waxes—U.S. data on C stocks and flows were used to develop C storage factors, calculated as the ratio of (a) the C stored by the fuel's non-energy products to (b) the total C content of the fuel consumed. A

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[27] These source categories include Iron and Steel Production, Lead Production, Zinc Production, Ammonia Manufacture, Carbon Black Manufacture (included in Petrochemical Production), Titanium Dioxide Production, Ferroalloy Production, Silicon Carbide Production, and Aluminum Production.

lifecycle approach was used in the development of these factors in order to account for losses in the production process and during use. Because losses associated with municipal solid waste management are handled separately in this sector under the Municipal Solid Waste Combustion source category, the storage factors do not account for losses at the disposal end of the life cycle. For industrial coking coal and distillate fuel oil, storage factors were taken from IPCC/UNEP/OECD/IEA (1997), which in turn draws from Marland and Rotty (1984). For the remaining fuel types (petroleum coke, miscellaneous products, and other petroleum), IPCC does not provide guidance on storage factors, and assumptions were made based on the potential fate of C in the respective NEU products.

Table 3-12: Adjusted Consumption of Fossil Fuels for Non-Energy Uses (TBtu)

Year	1990	1995	2000	2001	2002	2003	2004	2005	2006
Industry	**4,221.2**	**4,771.8**	**5,261.1**	**5,044.4**	**5,032.4**	**4,865.3**	**5,308.4**	**5,210.0**	**5,160.5**
Industrial Coking Coal	0.0	43.9	62.8	25.6	46.5	72.1	214.7	109.7	85.9
Industrial Other Coal	8.2	11.3	12.4	11.3	12.0	11.9	11.9	11.9	12.4
Natural Gas to Chemical Plants, Other Uses	276.0	330.4	421.1	407.8	364.6	352.0	360.2	390.3	403.2
Asphalt & Road Oil	1,170.2	1,178.2	1,275.7	1,256.9	1,239.9	1,219.5	1,303.8	1,323.2	1,225.6
LPG	1,119.0	1,484.7	1,604.6	1,539.0	1,565.4	1,437.8	1,436.7	1,442.0	1,491.8
Lubricants	186.3	177.8	189.9	174.0	171.9	159.0	161.0	160.2	130.6
Pentanes Plus	77.3	285.3	228.7	199.8	166.1	158.3	156.5	146.0	105.1
Naphtha (<401 ° F)	325.7	350.6	592.8	489.4	564.2	573.4	687.9	678.6	592.9
Other Oil (>401 ° F)	677.2	612.7	554.3	525.9	456.2	501.0	547.8	518.7	573.4
Still Gas	21.3	40.1	12.6	35.8	57.8	59.0	63.5	67.7	122.3
Petroleum Coke	81.0	44.1	47.8	128.1	110.2	76.9	161.3	145.0	178.7
Special Naphtha	100.9	66.9	94.4	77.9	99.5	75.7	47.2	60.9	68.7
Distillate Fuel Oil	7.0	8.0	11.7	11.7	11.7	11.7	11.7	11.7	11.7
Waxes	33.3	40.6	33.1	36.3	32.2	31.0	30.8	31.4	25.2
Miscellaneous Products	137.8	97.1	119.2	124.9	134.2	126.0	113.4	112.8	133.2
Transportation	176.0	167.9	179.4	164.3	162.4	150.1	152.1	151.3	147.0
Lubricants	176.0	167.9	179.4	164.3	162.4	150.1	152.1	151.3	147.0
U.S. Territories	86.7	90.8	165.5	80.3	138.6	127.9	110.8	107.6	110.3
Lubricants	0.7	2.0	16.4	+	1.5	9.3	5.1	5.2	5.4
Other Petroleum (Misc. Prod.)	86.0	88.8	149.1	80.3	137.2	118.6	105.7	102.4	104.9
Total	4,483.9	5,030.6	5,605.9	5,289.0	5,333.4	5,143.4	5,571.3	5,468.9	5,417.8

+ Does not exceed 0.05 TBtu

Note: To avoid double-counting, coal coke, petroleum coke, natural gas consumption, and other oils are adjusted for industrial process consumption reported in the Industrial Processes sector. Natural gas, LPG, Pentanes Plus, Naphthas, Special Naphtha, and Other Oils are adjusted to account for exports of chemical intermediates derived from these fuels. For residual oil (not shown in the table), all non-energy use is assumed to be consumed in C black production, which is also reported in the Industrial Processes chapter.

Note: Totals may not sum due to independent rounding.

Table 3-13: 2006 Adjusted Non-Energy Use Fossil Fuel Consumption, Storage, and Emissions

Sector/Fuel Type	Adjusted Non-Energy Use[a] (TBtu)	Carbon Content Coefficient (Tg C/QBtu)	Potential Carbon (Tg C)	Storage Factor	Carbon Stored (Tg C)	Carbon Emissions (Tg C)	Carbon Emissions (Tg CO$_2$ Eq.)
Industry	**5,160.5**	-	**97.8**	-	**64.9**	**32.9**	**120.8**
Industrial Coking Coal	85.9	31.00	2.7	0.10	0.3	2.4	8.8
Industrial Other Coal	12.4	25.63	0.3	0.62	0.2	0.1	0.4
Natural Gas to Chemical Plants	403.2	14.47	5.8	0.62	3.6	2.2	8.2
Asphalt & Road Oil	1,225.6	20.62	25.3	1.00	25.3	0.0	0.0
LPG	1,491.8	16.78	25.0	0.62	15.4	9.6	35.3
Lubricants	130.6	20.24	2.6	0.09	0.2	2.4	8.8

Pentanes Plus	105.1	18.24	1.9	0.62	1.2	0.7	2.7
Naphtha (<401° F)	592.9	18.14	10.8	0.62	6.6	4.1	15.2
Other Oil (>401° F)	573.4	19.95	11.4	0.62	7.0	4.4	16.1
Still Gas	122.3	17.51	2.1	0.62	1.3	0.8	3.0
Petroleum Coke	178.7	27.85	5.0	0.50	2.5	2.5	9.1
Special Naphtha	68.7	19.86	1.4	0.62	0.8	0.5	1.9
Distillate Fuel Oil	11.7	19.95	0.2	0.50	0.1	0.1	0.4
Waxes	25.2	19.81	0.5	0.58	0.3	0.2	0.8
Miscellaneous Products	133.2	20.33	2.7	0.00	0.0	2.7	9.9
Transportation	**147.0**	**-**	**3.0**	**-**	**0.3**	**2.7**	**9.9**
Lubricants	147.0	20.24	3.0	0.09	0.3	2.7	9.9
U.S. Territories	**110.3**	**-**	**2.2**	**-**	**0.2**	**2.0**	**7.3**
Lubricants	5.4	20.24	0.1	0.09	0.0	0.1	0.4
Other Petroleum (Misc. Prod.)	104.9	20.00	2.1	0.10	0.2	1.89	6.9
Total	**5,417.8**		**103.0**		**65.4**	**37.6**	**138.0**

+ Does not exceed 0.05 TBtu

- Not applicable.

[a] To avoid double counting, exports have been deducted.

Note: Totals may not sum due to independent rounding.

Lastly, emissions were estimated by subtracting the C stored from the potential emissions (see Table 3-11). More detail on the methodology for calculating storage and emissions from each of these sources is provided in Annex 2.3.

Where storage factors were calculated specifically for the United States, data were obtained on (1) products such as asphalt, plastics, synthetic rubber, synthetic fibers, cleansers (soaps and detergents), pesticides, food additives, antifreeze and deicers (glycols), and silicones; and (2) industrial releases including volatile organic compound, solvent, and non-combustion CO emissions, Toxics Release Inventory (TRI) releases, hazardous waste incineration, and energy recovery. Data were taken from a variety of industry sources, government reports, and expert communications. Sources include EPA reports and databases such as compilations of air emission factors (EPA 1995, 2001), *National Air Quality and Emissions Trends Report* (EPA 2006a), *Toxics Release Inventory, 1998* (2000a), *Biennial Reporting System* (EPA 2004a, 2006b, 2007), and pesticide sales and use estimates (EPA 1998, 1999, 2002, 2004b); the EIA Manufacturer's Energy Consumption Survey (MECS) (EIA 1994, 1997, 2001, 2005); the National Petrochemical & Refiners Association (NPRA 2001); the National Asphalt Pavement Association (Connolly 2000); the Emissions Inventory Improvement Program (EIIP 1998, 1999); the U.S. Census Bureau (1999, 2003, 2004); the American Plastics Council (APC 2000, 2001, 2003, 2005, 2006; Eldredge-Roebuck 2000); the Society of the Plastics Industry (SPI 2000); Bank of Canada (2006); Financial Planning Association (2006); INEGI (2006); Statistics Canada (2006); the United States International Trade Commission (2006, 2007); the Pesticide Action Network (PAN 2002); Gosselin, Smith, and Hodge (1984); the Rubber Manufacturers' Association (RMA 2002, 2006; STMC 2003); the International Institute of Synthetic Rubber Products (IISRP 2000, 2003); the Fiber Economics Bureau (FEB 2001, 2003, 2005 through 2007); the *Material Safety Data Sheets* (Miller 1999); the Chemical Manufacturer's Association (CMA 1999); and the American Chemistry Council (ACC 2005 through 2007) Specific data sources are listed in full detail in Annex 2.3.

Uncertainty

An uncertainty analysis was conducted to quantify the uncertainty surrounding the estimates of emissions and storage factors from non-energy uses. This analysis, performed using @RISK software and the IPCC-recommended Tier 2 methodology (Monte Carlo Simulation technique), provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. The results presented below provide the 95 percent confidence interval, the range of values within which emissions are likely to fall, for this source category.

As noted above, the non-energy use analysis is based on U.S.-specific storage factors for (1) feedstock materials (natural gas, LPG, pentanes plus, naphthas, other oils, still gas, special naphthas, and other industrial coal), (2)

asphalt, (3) lubricants, and (4) waxes. For the remaining fuel types (the "other" category), the storage factors were taken directly from the IPCC *Guidelines for National Greenhouse Gas Inventories*, where available, and otherwise assumptions were made based on the potential fate of carbon in the respective NEU products. To characterize uncertainty, five separate analyses were conducted, corresponding to each of the five categories. In all cases, statistical analyses or expert judgments of uncertainty were not available directly from the information sources for all the activity variables; thus, uncertainty estimates were determined using assumptions based on source category knowledge.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-14 (emissions) and Table 3-15 (storage factors). Carbon emitted from non-energy uses of fossil fuels in 2006 was estimated to be between 110.2 and 150.3 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 20 percent below to 9 percent above the 2006 emission estimate of 138.0 Tg CO_2 Eq. The uncertainty in the emission estimates is a function of uncertainty in both the quantity of fuel used for non-energy purposes and the storage factor.

Table 3-14: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Non-Energy Uses of Fossil Fuels (Tg CO_2 Eq. and Percent)

Source	Gas	2006 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Feedstocks	CO_2	83.0	66.4	99.5	-20%	+20%
Asphalt	CO_2	0.0	0.1	0.7	NA	NA
Lubricants	CO_2	19.1	15.7	22.1	-17%	+16%
Waxes	CO_2	0.8	0.6	1.2	-23%	+59%
Other	CO_2	35.2	16.5	38.3	-53%	+9%
Total	**CO_2**	**138.0**	**110.2**	**150.3**	**-20%**	**+9%**

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.
NA (Not Applicable)

Table 3-15: Tier 2 Quantitative Uncertainty Estimates for Storage Factors of Non-Energy Uses of Fossil Fuels (Percent)

Source	Gas	2006 Storage Factor (%)	Uncertainty Range Relative to Emission Estimate[a] (%)		(%, Relative)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Feedstocks	CO_2	62%	59%	64%	-4%	+3%
Asphalt	CO_2	100%	99%	100%	-1%	+0%
Lubricants	CO_2	9%	4%	18%	-58%	+89%
Waxes	CO_2	58%	44%	69%	-24%	+19%
Other	CO_2	24%	20%	64%	-17%	+162%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval, as a percentage of the inventory value (also expressed in percent terms).

In Table 3-15, feedstocks and asphalt contribute least to overall storage factor uncertainty on a percentage basis. Although the feedstocks category—the largest use category in terms of total carbon flows—appears to have tight confidence limits, this is to some extent an artifact of the way the uncertainty analysis was structured. As discussed in Annex 2.3, the storage factor for feedstocks is based on an analysis of six fates that result in long-term storage (e.g., plastics production), and eleven that result in emissions (e.g., volatile organic compound emissions). Rather than modeling the total uncertainty around all of these fate processes, the current analysis addresses only the storage fates, and assumes that all C that is not stored is emitted. As the production statistics that drive the storage values are relatively well-characterized, this approach yields a result that is probably biased toward understating

uncertainty.

As is the case with the other uncertainty analyses discussed throughout this document, the uncertainty results above address only those factors that can be readily quantified. More details on the uncertainty analysis are provided in Annex 2.3.

QA/QC and Verification

A source-specific QA/QC plan for non-energy uses of fossil fuels was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis for non-energy uses involving petrochemical feedstocks and for imports and exports. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and methodology for estimating the fate of C (in terms of storage and emissions) across the various end-uses of fossil C. Emission and storage totals for the different subcategories were compared, and trends across the time series were analyzed to determine whether any corrective actions were needed. Corrective actions were taken to rectify minor errors and to improve the transparency of the calculations, facilitating future QA/QC.

For petrochemical import and export data, special attention was paid to NAICS numbers and titles to verify that none had changed or been removed. Import and export totals were compared for 2006 as well as their trends across the time series.

Planned Improvements

There are several improvements planned for the future:

- Future updates in line with the 2006 IPCC Guidelines. These changes could affect both the non-energy use and industrial processes sections.

- Improving the uncertainty analysis. Most of the input parameter distributions are based on professional judgment rather than rigorous statistical characterizations of uncertainty.

- Better characterizing flows of fossil C. Additional "fates" may be researched, including the fossil C load in organic chemical wastewaters, plasticizers, adhesives, films, paints, and coatings. There is also a need to further clarify the treatment of fuel additives and backflows (especially methyl tert-butyl ether, MTBE).

Finally, although U.S.-specific storage factors have been developed for feedstocks, asphalt, lubricants, and waxes, default values from IPCC are still used for two of the non-energy fuel types (industrial coking coal and distillate oil), and broad assumptions are being used for the remaining fuels (petroleum coke, miscellaneous products, and other petroleum). Over the long term, there are plans to improve these storage factors by conducting analyses of C fate similar to those described in Annex 2.3.

3.3. *Stationary Combustion (excluding CO_2) (IPCC Source Category 1A)*

Stationary combustion encompasses all fuel combustion activities from fixed sources (versus mobile combustion). Other than CO_2, which was addressed in the previous section, gases from stationary combustion include the greenhouse gases CH_4 and N_2O and the indirect greenhouse gases NO_x, CO, and NMVOCs.[28] Emissions of these gases from stationary combustion sources depend upon fuel characteristics, size and vintage, along with combustion technology, pollution control equipment, and ambient environmental conditions. Emissions also vary with operation and maintenance practices.

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[28] Sulfur dioxide (SO_2) emissions from stationary combustion are addressed in Annex 6.3.

N_2O emissions from stationary combustion are closely related to air-fuel mixes and combustion temperatures, as well as the characteristics of any pollution control equipment that is employed. CH_4 emissions from stationary combustion are primarily a function of the CH_4 content of the fuel and combustion efficiency.

Emissions of CH_4 decreased 16 percent overall since 1990 to 6.2 Tg CO_2 Eq. (296 Gg) in 2006. This decrease in CH_4 emissions was primarily due to lower wood consumption in the residential sector. Conversely, N_2O emissions rose 13 percent since 1990 to 14.5 Tg CO_2 Eq. (47 Gg) in 2006. The largest source of N_2O emissions was coal combustion by electricity generators, which alone accounted for 66 percent of total N_2O emissions from stationary combustion in 2006. Overall, however, stationary combustion is a small source of CH_4 and N_2O in the United States.

Table 3-16: CH_4 Emissions from Stationary Combustion (Tg CO_2 Eq.)

Sector/Fuel Type	1990	1995	2000	2001	2002	2003	2004	2005	2006
Electric Power	**0.6**	**0.6**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**
Coal	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Fuel Oil	0.1	+	0.1	0.1	0.1	0.1	0.1	0.1	+
Natural gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wood	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Industrial	**1.5**	**1.6**	**1.6**	**1.5**	**1.4**	**1.4**	**1.5**	**1.5**	**1.5**
Coal	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Fuel Oil	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Natural gas	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1
Wood	0.9	1.0	1.0	0.9	0.8	0.8	0.9	0.9	0.9
Commercial/Institutional	**0.9**	**0.9**	**0.9**	**0.9**	**0.9**	**0.9**	**0.9**	**0.9**	**0.8**
Coal	+	+	+	+	+	+	+	+	+
Fuel Oil	0.2	0.1	0.1	0.1	0.1	0.2	0.1	0.1	0.1
Natural gas	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Wood	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Residential	**4.4**	**4.0**	**3.4**	**3.1**	**3.1**	**3.3**	**3.3**	**3.3**	**3.1**
Coal	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	+
Fuel Oil	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Natural Gas	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.4
Wood	3.5	3.1	2.5	2.2	2.3	2.4	2.5	2.5	2.3
U.S. Territories	**+**	**+**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Coal	+	+	+	+	+	+	+	+	+
Fuel Oil	+	+	+	0.1	0.1	0.1	0.1	0.1	0.1
Natural Gas	+	+	+	+	+	+	+	+	+
Wood	+	+	+	+	+	+	+	+	+
Total	**7.4**	**7.2**	**6.6**	**6.2**	**6.2**	**6.4**	**6.5**	**6.5**	**6.2**

+ Does not exceed 0.05 Tg CO_2 Eq.
Note: Totals may not sum due to independent rounding.

Table 3-17: N_2O Emissions from Stationary Combustion (Tg CO_2 Eq.)

Sector/Fuel Type	1990	1995	2000	2001	2002	2003	2004	2005	2006
Electric Power	**8.1**	**8.6**	**10.0**	**9.7**	**9.7**	**10.0**	**10.0**	**10.3**	**10.1**
Coal	7.6	8.1	9.4	9.1	9.2	9.4	9.5	9.7	9.5
Fuel Oil	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.1
Natural Gas	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Wood	0.2	0.1	0.2	0.1	0.2	0.2	0.2	0.2	0.2
Industrial	**3.2**	**3.4**	**3.3**	**3.1**	**3.0**	**3.0**	**3.1**	**3.1**	**3.2**
Coal	0.8	0.7	0.7	0.7	0.6	0.6	0.6	0.6	0.6
Fuel Oil	0.5	0.4	0.5	0.5	0.5	0.5	0.5	0.6	0.6
Natural Gas	0.2	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2

Sector/Fuel Type	1990	1995	2000	2001	2002	2003	2004	2005	2006
Wood	1.7	1.9	1.9	1.7	1.6	1.6	1.7	1.7	1.7
Commercial/Institutional	**0.4**	**0.4**	**0.3**	**0.3**	**0.3**	**0.4**	**0.4**	**0.3**	**0.3**
Coal	0.1	0.1	+	+	+	+	+	+	+
Fuel Oil	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Natural Gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wood	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Residential	**1.1**	**1.0**	**0.9**	**0.9**	**0.9**	**0.9**	**0.9**	**0.9**	**0.8**
Coal	+	+	+	+	+	+	+	+	+
Fuel Oil	0.3	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.2
Natural Gas	0.1	0.1	0.2	0.1	0.1	0.2	0.1	0.1	0.1
Wood	0.7	0.6	0.5	0.4	0.4	0.5	0.5	0.5	0.5
U.S. Territories	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Coal	+	+	+	+	+	+	+	+	+
Fuel Oil	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Natural Gas	+	+	+	+	+	+	+	+	+
Wood	+	+	+	+	+	+	+	+	+
Total	**12.8**	**13.4**	**14.6**	**14.1**	**14.0**	**14.3**	**14.6**	**14.8**	**14.5**

+ Does not exceed 0.05 Tg CO_2 Eq.
Note: Totals may not sum due to independent rounding.

Table 3-18: CH_4 Emissions from Stationary Combustion (Gg)

Sector/Fuel Type	1990	1995	2000	2001	2002	2003	2004	2005	2006
Electric Power	**27**	**27**	**33**	**32**	**32**	**34**	**34**	**35**	**34**
Coal	16	18	20	20	20	20	20	21	21
Fuel Oil	4	2	3	4	3	4	4	4	2
Natural Gas	3	4	5	5	5	5	5	6	6
Wood	4	4	4	4	4	5	5	5	5
Industrial	**73**	**78**	**76**	**71**	**69**	**68**	**71**	**71**	**72**
Coal	16	15	14	14	13	13	13	13	13
Fuel Oil	9	7	7	8	8	8	9	9	10
Natural Gas	7	8	8	8	8	8	7	7	7
Wood	41	47	47	41	40	39	42	41	42
Commercial/Institutional	**41**	**43**	**43**	**41**	**42**	**44**	**43**	**42**	**40**
Coal	1	1	1	1	1	1	1	1	1
Fuel Oil	8	7	7	7	6	7	7	7	7
Natural Gas	13	15	15	15	15	16	15	15	14
Wood	19	21	20	19	20	20	20	20	18
Residential	**210**	**190**	**162**	**147**	**149**	**158**	**159**	**157**	**147**
Coal	9	5	3	3	4	4	4	3	2
Fuel Oil	14	13	15	15	14	15	15	14	13
Natural Gas	21	24	24	23	24	25	24	24	21
Wood	165	148	120	105	108	114	117	117	111
U.S. Territories	**2**	**2**	**2**	**3**	**3**	**3**	**3**	**3**	**3**
Coal	+	+	+	+	+	+	+	+	+
Fuel Oil	2	2	2	3	3	3	3	3	3
Natural Gas	+	+	+	+	+	+	+	+	+
Wood	+	+	+	+	+	+	+	+	+
Total	**353**	**341**	**316**	**295**	**295**	**306**	**311**	**308**	**296**

+ Does not exceed 0.5 Gg
Note: Totals may not sum due to independent rounding.

Table 3-19: N_2O Emissions from Stationary Combustion (Gg)

Sector/Fuel Type	1990	1995	2000	2001	2002	2003	2004	2005	2006
Electric Power	**26**	**28**	**32**	**31**	**31**	**32**	**32**	**33**	**32**
Coal	24	26	30	29	30	30	31	31	31
Fuel Oil	1	+	1	1	1	1	1	1	+
Natural Gas	+	+	1	1	1	+	1	1	1
Wood	+	+	1	+	1	1	1	1	1
Industrial	**10**	**11**	**11**	**10**	**10**	**10**	**10**	**10**	**10**
Coal	2	2	2	2	2	2	2	2	2
Fuel Oil	2	1	1	2	2	2	2	2	2
Natural Gas	1	1	1	1	1	1	1	1	1
Wood	5	6	6	5	5	5	6	6	6
Commercial/Institutional	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**
Coal	+	+	+	+	+	+	+	+	+
Fuel Oil	+	+	+	+	+	+	+	+	+
Natural Gas	+	+	+	+	+	+	+	+	+
Wood	+	+	+	+	+	+	+	+	+
Residential	**4**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**
Coal	+	+	+	+	+	+	+	+	+
Fuel Oil	1	1	1	1	1	1	1	1	1
Natural Gas	+	+	+	+	+	+	+	+	+
Wood	2	2	2	1	1	2	2	2	1
U.S. Territories	**+**	**+**	**+**	**+**	**+**	**+**	**+**	**+**	**+**
Coal	+	+	+	+	+	+	+	+	+
Fuel Oil	+	+	+	+	+	+	+	+	+
Natural Gas	+	+	+	+	+	+	+	+	+
Wood	+	+	+	+	+	+	+	+	+
Total	**41**	**43**	**47**	**46**	**45**	**46**	**47**	**48**	**47**

+ Does not exceed 0.5 Gg
Note: Totals may not sum due to independent rounding.

Methodology

CH_4 and N_2O emissions were estimated by multiplying fossil fuel and wood consumption data by emission factors (by sector and fuel type). National coal, natural gas, fuel oil, and wood consumption data were grouped by sector: industrial, commercial, residential, electricity generation, and U.S. territories. For the CH_4 and N_2O estimates, fuel consumption data for coal, natural gas, fuel oil for the United States were obtained from EIA's *Monthly Energy Review* and unpublished supplemental tables on petroleum product detail (EIA 2007a). Wood consumption data for the United States was obtained from EIA's *Annual Energy Review* (EIA 2007b). Because the United States does not include territories in its national energy statistics, fuel consumption data for territories were provided separately by Grillot (2007).[29] Fuel consumption for the industrial sector was adjusted to subtract out construction and agricultural use, which is reported under mobile sources.[30] Construction and agricultural fuel use was obtained from EPA (2004). Estimates for wood biomass consumption for fuel combustion do not include wood wastes, liquors, municipal solid waste, tires, etc. that are reported as biomass by EIA.

[29] U.S. territories data also include combustion from mobile activities because data to allocate territories' energy use were unavailable. For this reason, CH_4 and N_2O emissions from combustion by U.S. territories are only included in the stationary combustion totals.

[30] Though emissions from construction and farm use occur due to both stationary and mobile sources, detailed data was not available to determine the magnitude from each. Currently, these emissions are assumed to be predominantly from mobile sources.

Emission factors for the four end-use sectors were provided by the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC 2006). U.S. territories' emission factors were estimated using the U.S. emission factors for the primary sector in which each fuel was combusted.

More detailed information on the methodology for calculating emissions from stationary combustion, including emission factors and activity data, is provided in Annex 3.1.

Uncertainty

CH_4 emission estimates from stationary sources exhibit high uncertainty, primarily due to difficulties in calculating emissions from wood combustion (i.e., fireplaces and wood stoves). The estimates of CH_4 and N_2O emissions presented are based on broad indicators of emissions (i.e., fuel use multiplied by an aggregate emission factor for different sectors), rather than specific emission processes (i.e., by combustion technology and type of emission control).

An uncertainty analysis was performed by primary fuel type for each end-use sector, using the IPCC-recommended Tier 2 uncertainty estimation methodology, Monte Carlo Simulation technique, with @RISK software.

The uncertainty estimation model for this source category was developed by integrating the CH_4 and N_2O stationary source inventory estimation models with the model for CO_2 from fossil fuel combustion to realistically characterize the interaction (or endogenous correlation) between the variables of these three models. A total of 115 input variables were simulated for the uncertainty analysis of this source category (85 from the CO_2 emissions from fossil fuel combustion inventory estimation model and 30 from the stationary source inventory models).

In developing the uncertainty estimation model, uniform distribution was assumed for all activity-related input variables and N_2O emission factors, based on the SAIC/EIA (2001) report.[31] For these variables, the uncertainty ranges were assigned to the input variables based on the data reported in SAIC/EIA (2001).[32] However, the CH_4 emission factors differ from those used by EIA. Since these factors were obtained from IPCC/UNEP/OECD/IEA (1997), uncertainty ranges were assigned based on IPCC default uncertainty estimates (IPCC 2000).

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-20. Stationary combustion CH_4 emissions in 2006 (*including* biomass) were estimated to be between 4.3 and 13.4 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 31 percent below to 116 percent above the 2006 emission estimate of 6.2 Tg CO_2 Eq.[33] Stationary combustion N_2O emissions in 2006 (*including* biomass) were estimated to be between 11.0 and 42.2 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 24 percent below to 190 percent above the 2006 emissions estimate of 14.5 Tg CO_2 Eq.

Table 3-20: Tier 2 Quantitative Uncertainty Estimates for CH_4 and N_2O Emissions from Energy-Related Stationary Combustion, Including Biomass (Tg CO_2 Eq. and Percent)

	2006 Emission Estimate	Uncertainty Range Relative to Emission Estimate[a]

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[31] SAIC/EIA (2001) characterizes the underlying probability density function for the input variables as a combination of uniform and normal distributions (the former distribution to represent the bias component and the latter to represent the random component). However, for purposes of the current uncertainty analysis, it was determined that uniform distribution was more appropriate to characterize the probability density function underlying each of these variables.

[32] In the SAIC/EIA (2001) report, the quantitative uncertainty estimates were developed for each of the three major fossil fuels used within each end-use sector; the variations within the sub-fuel types within each end-use sector were not modeled. However, for purposes of assigning uncertainty estimates to the sub-fuel type categories within each end-use sector in the current uncertainty analysis, SAIC/EIA (2001)-reported uncertainty estimates were extrapolated.

[33] The low emission estimates reported in this section have been rounded down to the nearest integer values and the high emission estimates have been rounded up to the nearest integer values.

Source	Gas	(Tg CO_2 Eq.)	(Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Stationary Combustion	CH_4	6.2	4.3	13.4	-31%	+116%
Stationary Combustion	N_2O	14.5	11.0	42.2	-24%	+190%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

The uncertainties associated with the emission estimates of CH_4 and N_2O are greater than those associated with estimates of CO_2 from fossil fuel combustion, which mainly rely on the carbon content of the fuel combusted. Uncertainties in both CH_4 and N_2O estimates are due to the fact that emissions are estimated based on emission factors representing only a limited subset of combustion conditions. For the indirect greenhouse gases, uncertainties are partly due to assumptions concerning combustion technology types, age of equipment, emission factors used, and activity data projections.

QA/QC and Verification

A source-specific QA/QC plan for stationary combustion was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and emission factor sources and methodology used for estimating CH_4, N_2O, and the indirect greenhouse gases from stationary combustion in the United States. Emission totals for the different sectors and fuels were compared and trends were investigated.

Recalculations Discussion

Historical CH_4 and N_2O emissions from stationary sources (excluding CO_2) were revised due to several changes. One of the most significant changes was implementing stationary combustion emission factors updated in IPCC (2006). As a result, N_2O emission factors for coal consumption in all sectors, and CH_4 emission factors for industrial petroleum and natural gas were revised. Slight changes to emission estimates for sectors are also due to revised data from EIA (2007a). This revision is explained in greater detail in the section on CO_2 Emissions from Fossil Fuel Combustion within this sector. Wood consumption data from EIA (2007b) were revised for the residential, industrial, and electric power sectors. The combination of the methodological and historical data changes resulted in an average annual decrease of 0.6 Tg CO_2 Eq. (8.3 percent) in CH_4 emissions from stationary combustion and an average annual increase of 0.6 Tg CO_2 Eq. (4.9 percent) in N_2O emissions from stationary combustion for the period 1990 through 2005.

Planned Improvements

Several items are being evaluated to improve the CH_4 and N_2O emission estimates from stationary combustion and to reduce uncertainty. Efforts will be taken to work with EIA and other agencies to improve the quality of the U.S. territories data. Because these data are not broken out by stationary and mobile uses, further research will be aimed at trying to allocate consumption appropriately. In addition, the uncertainty of biomass emissions will be further investigated since it was expected that the exclusion of biomass from the uncertainty estimates would reduce the uncertainty; and in actuality the exclusion of biomass increases the uncertainty. These improvements are not all-inclusive, but are part of an ongoing analysis and efforts to continually improve these stationary estimates.

3.4. Mobile Combustion (excluding CO_2) (IPCC Source Category 1A)

Mobile combustion produces greenhouse gases other than CO_2, including CH_4, N_2O, and indirect greenhouse gases including NO_x, CO, and NMVOCs. Mobile combustion includes all transportation sources identified in the U.S. inventory with the exception of pipelines, which are stationary; mobile sources also include non-transportation sources such as construction/mining equipment, agricultural equipment, vehicles used off-road, and other sources that have utility associated with their movement but do not have a primary purpose of transporting people or goods (e.g., snowmobiles, riding lawnmowers, etc.). Annex 3.2 includes a summary of all emissions from both transportation and mobile sources.

As with stationary combustion, N_2O and NO_x emissions are closely related to fuel characteristics, air-fuel mixes, combustion temperatures, and the use of pollution control equipment. N_2O, in particular, can be formed by the catalytic processes used to control NO_x, CO, and hydrocarbon emissions. Carbon monoxide emissions from mobile combustion are significantly affected by combustion efficiency and the presence of post-combustion emission controls. CO emissions are highest when air-fuel mixtures have less oxygen than required for complete combustion. These emissions occur especially in idle, low speed, and cold start conditions. CH_4 and NMVOC emissions from motor vehicles are a function of the CH_4 content of the motor fuel, the amount of hydrocarbons passing uncombusted through the engine, and any post-combustion control of hydrocarbon emissions (such as catalytic converters).

Table 3-21 and Table 3-22 provide CH_4 and N_2O emission estimates in Tg CO_2 Eq.; Table 3-23 and Table 3-24 present these estimates in Gg of each gas.[34]

Mobile combustion was responsible for a small portion of national CH_4 emissions (0.4 percent) but was the second largest source of U.S. N_2O emissions (9 percent). From 1990 to 2006, mobile source CH_4 emissions declined by 50 percent, to 2.4 Tg CO_2 Eq. (112 Gg), due largely to control technologies employed in on-road vehicles since the mid-1990s to reduce CO, NO_x, NMVOC, and CH_4 emissions. Mobile source emissions of N_2O decreased by 24 percent, to 33.1 Tg CO_2 Eq (107 Gg). Earlier generation control technologies initially resulted in higher N_2O emissions, causing a 26 percent increase in N_2O emissions from mobile sources between 1990 and 1998. Improvements in later-generation emission control technologies have reduced N_2O output, resulting in a 40 percent decrease in mobile source N_2O emissions from 1998 to 2006 (see Figure 3-15). Overall, CH_4 and N_2O emissions were predominantly from gasoline-fueled passenger cars and light-duty trucks.

Figure 3-15: Mobile Source CH_4 and N_2O Emissions

Table 3-21: CH_4 Emissions from Mobile Combustion (Tg CO_2 Eq.)

Fuel Type/Vehicle Type[a]	1990	1995	2000	2001	2002	2003	2004	2005	2006
Gasoline On-Road	**4.2**	**3.8**	**2.8**	**2.7**	**2.4**	**2.2**	**2.0**	**1.9**	**1.7**
Passenger Cars	2.6	2.1	1.6	1.5	1.4	1.3	1.2	1.1	1.0
Light-Duty Trucks	1.4	1.4	1.1	1.1	0.9	0.8	0.7	0.7	0.7
Medium- and Heavy-Duty Trucks and Buses	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Motorcycles	+	+	+	+	+	+	+	+	+
Diesel On-Road	**+**	**+**	**+**	**+**	**+**	**+**	**+**	**+**	**+**
Passenger Cars	+	+	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+	+	+
Medium- and Heavy-Duty Trucks and Buses	+	+	+	+	+	+	+	+	+
Alternative Fuel On-Road	**+**	**+**	**+**	**+**	**+**	**+**	**0.1**	**0.1**	**0.1**
Non-Road	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.6**	**0.6**
Ships and Boats - Domestic	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Rail	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Agricultural Equipment	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Construction/Mining	+	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1

[34] See Annex 3.2 for a complete time series of emission estimates for 1990 through 2006.

Equipment									
Aircraft - Domestic	0.2	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.1
Other[b]	+	+	+	+	0.1	0.1	0.1	0.1	0.1
Total	**4.7**	**4.3**	**3.4**	**3.3**	**3.0**	**2.7**	**2.6**	**2.5**	**2.4**

+ Less than 0.05 Tg CO_2 Eq.
Note: Totals may not sum due to independent rounding.
[a] See Annex 3.2 for definitions of on-road vehicle types.
[b] "Other" includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment.

Table 3-22: N_2O Emissions from Mobile Combustion (Tg CO_2 Eq.)

Fuel Type/Vehicle Type	1990	1995	2000	2001	2002	2003	2004	2005	2006
Gasoline On-Road	**40.1**	**49.8**	**48.4**	**45.9**	**41.8**	**38.4**	**35.6**	**32.1**	**29.0**
Passenger Cars	25.4	26.9	25.2	23.8	22.5	21.0	19.5	17.7	15.6
Light-Duty Trucks	14.1	22.1	22.4	21.2	18.5	16.5	15.3	13.6	12.6
Medium- and Heavy- Duty Trucks and Buses	0.6	0.7	0.9	0.9	0.9	0.9	0.8	0.8	0.7
Motorcycles	+	+	+	+	+	+	+	+	+
Diesel On-Road	**0.2**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**
Passenger Cars	+	+	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+	+	+
Medium- and Heavy- Duty Trucks and Buses	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Alternative Fuel On- Road	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.2**	**0.2**	**0.2**	**0.2**
Non-Road	**3.2**	**3.3**	**3.7**	**3.6**	**3.6**	**3.4**	**3.6**	**3.7**	**3.6**
Ships and Boats - Domestic	0.4	0.4	0.5	0.3	0.5	0.3	0.4	0.4	0.4
Rail	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4
Agricultural Equipment	0.2	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4
Construction/Mining Equipment	0.3	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5
Aircraft - Domestic	1.7	1.7	1.9	1.8	1.7	1.7	1.7	1.7	1.6
Other*	0.2	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4
Total	**43.5**	**53.4**	**52.5**	**49.9**	**45.9**	**42.3**	**39.7**	**36.3**	**33.1**

+ Less than 0.05 Tg CO_2 Eq.
Note: Totals may not sum due to independent rounding.
*"Other" includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment.

Table 3-23: CH_4 Emissions from Mobile Combustion (Gg)

Fuel Type/Vehicle Type	1990	1995	2000	2001	2002	2003	2004	2005	2006
Gasoline On-Road	**201**	**180**	**134**	**129**	**112**	**103**	**96**	**88**	**82**
Passenger Cars	125	101	77	72	66	61	56	52	47
Light-Duty Trucks	65	69	50	52	41	38	35	32	31
Medium- and Heavy- Duty Trucks and Buses	10	9	5	5	4	4	4	3	3
Motorcycles	1	1	1	1	1	1	1	1	1
Diesel On-Road	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**
Passenger Cars	+	+	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+	+	+
Medium- and Heavy- Duty Trucks and Buses	1	1	1	1	1	1	1	1	1
Alternative Fuel On-	**+**	**+**	**1**	**2**	**2**	**2**	**3**	**3**	**3**

	1990	1995	2000	2001	2002	2003	2004	2005	2006
Road									
Non-Road	**22**	**24**	**26**	**25**	**26**	**24**	**26**	**27**	**27**
Ships and Boats - Domestic	3	4	5	3	4	3	3	4	3
Rail	3	3	3	3	3	3	4	4	4
Agricultural Equipment	4	5	5	6	6	6	6	7	7
Construction/Mining Equipment	2	3	3	3	3	3	3	4	4
Aircraft - Domestic	7	7	7	7	7	6	7	7	7
Other*	2	2	2	2	2	3	3	3	3
Total	**224**	**205**	**162**	**157**	**141**	**131**	**126**	**119**	**112**

+ Less than 0.5 Gg

Note: Totals may not sum due to independent rounding.

* "Other" includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment.

Table 3-24: N$_2$O Emissions from Mobile Combustion (Gg)

Fuel Type/Vehicle Type	1990	1995	2000	2001	2002	2003	2004	2005	2006
Gasoline On-Road	129	161	156	148	135	124	115	104	93
Passenger Cars	82	87	81	77	72	68	63	57	50
Light-Duty Trucks	45	71	72	69	60	53	49	44	41
Medium- and Heavy-Duty Trucks and Buses	2	2	3	3	3	3	3	2	2
Motorcycles	+	+	+	+	+	+	+	+	+
Diesel On-Road	1	1	1	1	1	1	1	1	1
Passenger Cars	+	+	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+	+	+
Medium- and Heavy-Duty Trucks and Buses	1	1	1	1	1	1	1	1	1
Alternative Fuel On-Road	+	+	+	+	+	1	1	1	1
Non-Road	10	11	12	11	12	11	12	12	12
Ships and Boats - Domestic	1	1	2	1	2	1	1	1	1
Rail	1	1	1	1	1	1	1	1	1
Agricultural Equipment	1	1	1	1	1	1	1	1	1
Construction/Mining Equipment	1	1	1	1	1	2	2	2	2
Aircraft - Domestic	6	5	6	6	6	5	6	6	5
Other*	1	1	1	1	1	1	1	1	1
Total	140	172	169	161	148	137	128	117	107

+ Less than 0.5 Gg

Note: Totals may not sum due to independent rounding.

* "Other" includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment.

Methodology

Estimates of CH$_4$ and N$_2$O emissions from mobile combustion were calculated by multiplying emission factors by measures of activity for each fuel and vehicle type (e.g., light-duty gasoline trucks). Activity data included vehicle miles traveled (VMT) for on-road vehicles and fuel consumption for non-road mobile sources. The activity data and emission factors used are described in the subsections that follow. A complete discussion of the methodology used to estimate CH$_4$ and N$_2$O emissions from mobile combustion and the emission factors used in the calculations is provided in Annex 3.2.

EPA (2008, 2005, 2003) provides emission estimates of NO_x, CO, and NMVOCs for eight categories of on-road vehicles,[35] aircraft, and seven categories of non-road vehicles[36] These emission estimates primarily reflect EPA data, which, in final iteration, will be published on the National Emission Inventory (NEI) Air Pollutant Emission Trends web site. The methodology used to develop these estimates can be found on EPA's Air Pollutant Emission Trends website, at <http://www.epa.gov/ttn/chief/trends/index.html>.

On-Road Vehicles

Estimates of CH_4 and N_2O emissions from gasoline and diesel on-road vehicles are based on VMT and emission factors by vehicle type, fuel type, model year, and emission control technology. Emission estimates for alternative fuel vehicles (AFVs)[37] are based on VMT and emission factors by vehicle and fuel type.

Emission factors for gasoline and diesel on-road vehicles utilizing Tier 2 and Low Emission Vehicle (LEV) technologies were developed by ICF (2006b); all other gasoline and diesel on-road vehicle emissions factors were developed by ICF (2004). These factors were derived from EPA, California Air Resources Board (CARB) and Environment Canada laboratory test results of different vehicle and control technology types. The EPA, CARB and Environment Canada tests were designed following the Federal Test Procedure (FTP), which covers three separate driving segments, since vehicles emit varying amounts of GHGs depending on the driving segment. These driving segments are: (1) a transient driving cycle that includes cold start and running emissions, (2) a cycle that represents running emissions only, and (3) a transient driving cycle that includes hot start and running emissions. For each test run, a bag was affixed to the tailpipe of the vehicle and the exhaust was collected; the content of this bag was then analyzed to determine quantities of gases present. The emissions characteristics of segment 2 were used to define running emissions, and subtracted from the total FTP emissions to determine start emissions. These were then recombined based upon the ratio of start to running emissions for each vehicle class from MOBILE6.2, an EPA emission factor model that predicts gram per mile emissions of CO_2, CO, HC, NOx, and PM from vehicles under various conditions, to approximate average driving characteristics.[38]

Emission factors for AFVs were developed by ICF (2006a) after examining Argonne National Laboratory's GREET 1.7–Transportation Fuel Cycle Model (ANL 2006) and Lipman and Delucchi (2002). These sources describe AFV emission factors in terms of ratios to conventional vehicle emission factors. Ratios of AFV to conventional vehicle emissions factors were then applied to estimated Tier 1 emissions factors from light-duty gasoline vehicles to estimate light-duty AFVs. Emissions factors for heavy-duty AFVs were developed in relation to gasoline heavy-duty vehicles. A complete discussion of the data source and methodology used to determine emission factors from AFVs is provided in Annex 3.2.

Annual VMT data for 1990 through 2006 were obtained from the Federal Highway Administration's (FHWA) Highway Performance Monitoring System database as reported in *Highway Statistics* (FHWA 1996 through 2007). VMT estimates were then allocated from FHWA's vehicle categories to fuel-specific vehicle categories using the calculated shares of vehicle fuel use for each vehicle category by fuel type reported in DOE (1993 through 2007) and information on total motor vehicle fuel consumption by fuel type from FHWA (1996 through 2007). VMT for AFVs were taken from Browning (2003). The age distributions of the U.S. vehicle fleet were obtained from EPA (2007c, 2000), and the average annual age-specific vehicle mileage accumulation of U.S. vehicles were obtained

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[35] These categories included: gasoline passenger cars, diesel passenger cars, light-duty gasoline trucks less than 6,000 pounds in weight, light-duty gasoline trucks between 6,000 and 8,500 pounds in weight, light-duty diesel trucks, heavy-duty gasoline trucks and buses, heavy-duty diesel trucks and buses, and motorcycles.

[36] These categories included: locomotives, marine vessels, farm equipment, construction equipment, other non-road liquid fuel (e.g. recreational vehicles and lawn and garden equipment), and other non-road gaseous fuel (e.g., other non-road equipment running on compressed natural gas).

[37] Alternative fuel and advanced technology vehicles are those that can operate using a motor fuel other than gasoline or diesel. This includes electric or other bifuel or dual fuel vehicles that may be partially powered by gasoline or diesel.

[38] Additional information regarding the model can be found online at http://www.epa.gov/OMS/m6.htm.

from EPA (2000).

Control technology and standards data for on-road vehicles were obtained from EPA's Office of Transportation and Air Quality (EPA 2007a, 2007b, 2000, 1998, and 1997) and Browning (2005). These technologies and standards are defined in Annex 3.2, and were compiled from EPA (1993, 1994a, 1994b, 1998, 1999a) and IPCC/UNEP/OECD/IEA (1997).

These emission estimates were obtained from preliminary data (EPA 2008), and disaggregated based on EPA (2003), which, in its final iteration, will be published on the National Emission Inventory (NEI) Air Pollutant Emission Trends web site.

Non-Road Vehicles

To estimate emissions from non-road vehicles, fuel consumption data were employed as a measure of activity, and multiplied by fuel-specific emission factors (in grams of N_2O and CH_4 per kilogram of fuel consumed).[39] Activity data were obtained from AAR (2007), APTA (2007 and 2006), BEA (1991 through 2005), Benson (2002 through 2004), DHS (2008), DOC (1991 through 2007), DOE (1993 through 2007), DESC (2007), DOT (1991 through 2007), EIA (2007a, 2007b, 2007d, 2002), EIA (1991 through 2007), EPA (2006b), Esser (2003 through 2004), FAA (2007 and 2006), Gaffney (2007), Lou (2007), and Whorton (2006 through 2007). Emission factors for non-road modes were taken from IPCC/UNEP/OECD/IEA (1997).

Uncertainty

A quantitative uncertainty analysis was conducted for the on-road portion of the mobile source sector using the IPCC-recommended Tier 2 uncertainty estimation methodology, Monte Carlo simulation technique, using @RISK software. The uncertainty analysis was performed on 2006 estimates of CH_4 and N_2O emissions, incorporating probability distribution functions associated with the major input variables. For the purposes of this analysis, the uncertainty was modeled for the following two major sets of input variables: (1) vehicle miles traveled (VMT) data, by vehicle and fuel type and (2) emission factor data, by vehicle, fuel, and control technology type.

Uncertainty analyses were not conducted for NO_x, CO, or NMVOC emissions. Emission factors for these gases have been extensively researched since emissions of these gases from motor vehicles are regulated in the United States, and the uncertainty in these emission estimates is believed to be relatively low. However, a much higher level of uncertainty is associated with CH_4 and N_2O emission factors, because emissions of these gases are not regulated in the United States (and, therefore, there are not adequate emission test data), and because, unlike CO_2 emissions, the emission pathways of CH_4 and N_2O are highly complex.

The results of the Tier 2 quantitative uncertainty analysis for the mobile source CH_4 and N_2O emissions from on-road vehicles are summarized in Table 3-25. As noted above, an uncertainty analysis was not performed for CH_4 and N_2O emissions from non-road vehicles. Mobile combustion CH_4 emissions (from on-road vehicles) in 2006 were estimated to be between 1.7 and 1.9 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 6 percent below to 6 percent above the corresponding 2006 emission estimate of 1.8 Tg CO_2 Eq. Also at a 95 percent confidence level, mobile combustion N_2O emissions from on-road vehicles in 2006 were estimated to be between 23.8 and 35.2 Tg CO_2 Eq., indicating a range of 19 percent below to 19 percent above the corresponding 2006 emission estimate of 29.5 Tg CO_2 Eq.

Table 3-25. Tier 2 Quantitative Uncertainty Estimates for CH_4 and N_2O Emissions from Mobile Sources (Tg CO_2 Eq. and Percent)

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[39] The consumption of international bunker fuels is not included in these activity data, but is estimated separately under the International Bunker Fuels source category.

Source	Gas	2006 Emission Estimate[a] (Tg CO$_2$ Eq.)	Uncertainty Range Relative to Emission Estimate[a,b]			
			(Tg CO$_2$ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
On-Road Sources	CH$_4$	1.8	1.7	1.9	-6%	6%
On-Road Sources	N$_2$O	29.5	23.8	35.2	-19%	19%

[a] 2006 Emission estimates and the uncertainty range presented in this table correspond to on-road vehicles, comprising conventional and alternative fuel vehicles. Because the uncertainty associated with the emissions from non-road vehicles were not estimated, they were excluded in the estimates reported in this table.
[b] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

This uncertainty analysis is a continuation of a multi-year process for developing quantitative uncertainty estimates for this source category using the IPCC Tier 2 approach to uncertainty analysis. As a result, as new information becomes available, uncertainty characterization of input variables may be improved and revised. For additional information regarding uncertainty in emission estimates for CH$_4$ and N$_2$O please refer to the Uncertainty Annex.

QA/QC and Verification

A source-specific QA/QC plan for mobile combustion was developed and implemented. This plan is based on the IPCC-recommended QA-QC Plan. The specific plan used for mobile combustion was updated prior to collection and analysis of this current year of data. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures focused on the emission factor and activity data sources, as well as the methodology used for estimating emissions. These procedures included a qualitative assessment of the emissions estimates to determine whether they appear consistent with the most recent activity data and emission factors available. A comparison of historical emissions between the current Inventory and the previous Inventory was also conducted to ensure that the changes in estimates were consistent with the changes in activity data and emission factors.

Recalculations Discussion

In order to ensure that these estimates are continuously improved, the calculation methodology is revised annually based on comments from internal and external reviewers. A number of adjustments were made to the methodologies used in calculating emissions in the current Inventory.

Carbon dioxide emissions from gasoline-powered on-road sources are now calculated directly using "bottom-up" fuel sales data; this methodology is similar to the bottom-up calculation of CO$_2$ from transportation diesel sources implemented beginning with the 1990-2004 inventory report. On-road gasoline fuel sales estimates come from FHWA's Highway Statistics (FHWA 1996 through 2007). The ethanol component of these fuel sales is subtracted to yield a fossil-only estimate, which is used to calculate CO$_2$ for gasoline-powered passenger cars, light-duty trucks, medium- and heavy-duty trucks, and buses. To preserve EIA's estimate of total gasoline consumption across all sectors, adjustments were made to estimated gasoline consumption by recreational boats, the commercial sector and the industrial sector. EIA estimates of transportation sector fuel consumption continue to serve as the foundation of inventory estimates for other fuel types (jet fuel, aviation gasoline, residual fuel, natural gas, LPG and natural gas). CO$_2$ from these fuels continues to be apportioned to individual modes using bottom-up data from BTS, FAA, and DOE's Transportation Energy Data Book.

Vehicle age distributions for 1999 to the present were revised based on new data obtained from EPA's MOVES model (EPA 2007c). Diesel fractions for light trucks and medium- and heavy-duty trucks and buses were updated based on data obtained from the Transportation Energy Data Book (DOE 1993 through 2007) for 1998 through 2003, which increased emissions from diesel vehicles and reduced emissions from gasoline vehicles. Updates were made to alternative fuel vehicle (AFV) vehicle miles traveled (VMT) numbers based on new activity data (ICF 2006a) and biodiesel was also added as a vehicle category under alternative fuel vehicles. VMT and fuel consumption estimates for on-road vehicles were also revised for 2005 based on updated data from FHWA's *Highway Statistics* (FHWA 1996 through 2007).

Several changes were also made in the calculation of emissions from non-road vehicles. Similar to the previous inventory, commercial aircraft energy consumption estimates for 2000-2005 come from the Federal Aviation Administration's (FAA) System for Assessing Aviation's Global Emissions (SAGE) database (FAA 2006). Aviation estimates were developed without the availability of 2006 data from the Federal Aviation Administration's (FAA) System for Assessing Aviation's Global Emissions (SAGE) database. Estimates for 1990-1999 were calculated using fuel consumption estimates from the Bureau of Transportation Statistics (DOT 1991 through 2007) adjusted based on the 2000-2005 data. For 2006, an estimate – similar to the method used for 1990-1999 – was derived using a combination of data from BTS and SAGE data. Class II and III railroad diesel use estimates are now obtained from the American Short Line and Regional Railroad Association, with new data for 2002, 2004, and 2006 (Whorton 2006 through 2007).

+As a result of these changes, average estimates of CH_4 and N_2O emissions from mobile combustion were slightly lower relative to the previous inventory—showing a decrease of no more than 0.7 Tg CO_2 Eq. (2.0 percent) each year—for the period 1990 through 2000. Larger decreases in estimates occurred for years 2002 to 2005 when comparing the current inventory estimates with the previous inventory's estimates. The greatest decrease, 1.5 Tg CO_2 Eq. (4 percent), occurs with the 2005 N_2O estimate. Estimates for the year 2001 are the exception, as these estimates increased from the previous Inventory's estimates by 0.07 Tg CO_2 Eq. for CH_4 and 0.15 Tg CO_2 Eq. for N_2O.

Planned Improvements

While the data used for this report represent the most accurate information available, six areas have been identified that could potentially be improved in the short-term given available resources.

1. Develop new emission factors for non-road sources. The current inventory estimates for non-CO2 emissions from non-road sources are based on emission factors from IPCC guidelines published in 1996. Recent data on non-road sources from Environment Canada and the California Air Resources Board will be investigated in order to assess the feasibility of developing new N_2O and CH_4 emissions factors for non-road equipment.

2. Examine the feasibility of estimating aircraft N2O and CH4 emissions by the number of takeoffs and landings, instead of total fuel consumption. Various studies have indicated that aircraft N2O and CH4 emissions are more dependent on aircraft takeoffs and landings than on total aircraft fuel consumption; however, aircraft emissions are currently estimated from fuel consumption data. FAA's SAGE database contains detailed data on takeoffs and landings for each calendar year starting in 1999, and could potentially be used to conduct a Tier II analysis of aircraft emissions. This methodology will require a detailed analysis of the number of takeoffs and landings by aircraft type on domestic trips and development of procedures to develop comparable estimates for years prior to 1999. The feasibility of this approach will be explored.

3. Develop improved estimates of domestic waterborne fuel consumption. The inventory estimates for residual fuel used by ships and boats is based in part on data on bunker fuel use from the U.S. Department of Commerce. The Department of Homeland Security (DHS) maintains an electronic reporting system that automatically registers monthly sales of bunker fuel at ports, which should provide a more accurate and comprehensive estimate of residual bunker fuel use by reducing the amount of non-reporting. This system has been used to collect data since 2002, and these data could be incorporated into the development of inventory figures. The DHS figures will need to be reconciled with figures from the current sources of data and a methodology will need to be developed to produce updated estimates for prior years.

4. Develop improved estimates of domestic aviation fuel consumption. The inventory calculation of domestic jet fuel consumption is derived by first estimating international aviation bunker fuel consumption and subtracting this value from EIA's estimate of total jet fuel consumption. Aviation bunker fuel estimates involve a number of uncertainties, including the lack of specific data on the amount of total jet fuel consumption to allocate to international bunkers. As mentioned above, FAA's SAGE database contains detailed data of domestic operations of aircraft and associated fuel consumption, and could potentially be used for a direct calculation of commercial aviation fuel consumption similar to the bottom-up approaches currently used for transportation diesel sources and on-road gasoline.

5. Improve the process of apportioning VMT by vehicle type to each fuel type. The current inventory process for estimating VMT by vehicle/fuel type category involves apportioning VMT on the basis of fuel consumption. While this is a reasonable simplification, this approach implicitly assumes the same average fuel economy for gasoline and diesel vehicles. A more accurate apportionment of VMT by fuel type for light-duty trucks and medium/heavy-duty trucks could potentially be developed using data on vehicle travel from the Vehicle Inventory and Use Survey (U.S. Census Bureau 2000) and other publications, or using VMT breakdowns by vehicle/fuel type combinations from the MOBILE6 or MOVES models.

6. Continue to examine the use of EPA's MOVES model in the development of the inventory estimates, including use for uncertainty analysis. Although the inventory uses some of the underlying data from MOVES, such as vehicle age distributions by model year, MOVES is not used directly in calculating mobile source emissions. As MOVES goes through additional testing and refinement, the use of MOVES will be further explored.

3.5. Coal Mining (IPCC Source Category 1B1a)

Three types of coal mining related activities release CH_4 to the atmosphere: underground mining, surface mining, and post-mining (i.e., coal-handling) activities. Underground coal mines contribute the largest share of CH_4 emissions. All 120 gassy underground coal mines in the United States employ ventilation systems to ensure that CH_4 levels remain within safe concentrations. These systems can exhaust significant amounts of CH_4 to the atmosphere in low concentrations. Additionally, 20 U.S. coal mines supplement ventilation systems with degasification systems. Degasification systems are wells drilled from the surface or boreholes drilled inside the mine that remove large volumes of CH_4 before, during, or after mining. In 2006, 13 coal mines collected CH_4 from degasification systems and sold this gas to a pipeline, thus reducing emissions to the atmosphere. In addition, one coal mine used CH_4 from its degasification system to heat mine ventilation air on site. Two of the coal mines that sold gas to pipelines also used CH_4 to generate electricity or fuel a thermal coal dryer. Surface coal mines also release CH_4 as the overburden is removed and the coal is exposed, but the level of emissions is much lower than from underground mines. Finally, some of the CH_4 retained in the coal after mining is released during processing, storage, and transport of the coal.

Total CH_4 emissions in 2006 were estimated to be 58.5 Tg CO_2 Eq. (2,784 Gg), a decline of 30 percent since 1990 (see Table 3-26 and Table 3-27). Of this amount, underground mines accounted for 61 percent, surface mines accounted for 24 percent, and post-mining emissions accounted for 15 percent. The decline in CH_4 emissions from underground mines from 1996 to 2002 was the result of the reduction of overall coal production, the mining of less gassy coal, and an increase in CH_4 recovered and used. Since that time, underground coal production and the associated methane emissions have remained fairly level, while surface coal production and its associated emissions have steadily increased.

Table 3-26: CH_4 Emissions from Coal Mining (Tg CO_2 Eq.)

Activity	1990	1995	2000	2001	2002	2003	2004	2005	2006
Underground Mining	62.3	46.7	39.4	38.2	35.5	36.0	38.1	35.2	35.9
Liberated	67.9	59.1	55.0	55.5	54.7	53.0	53.2	52.3	54.6
Recovered & Used	(5.6)	(12.4)	(15.6)	(17.2)	(19.2)	(17.0)	(15.1)	(17.1)	(18.7)
Surface Mining	12.0	11.5	12.3	13.2	12.8	12.4	12.9	13.3	14.0
Post-Mining (Underground)	7.7	6.9	6.7	6.8	6.4	6.4	6.6	6.4	6.3
Post-Mining (Surface)	2.0	1.9	2.0	2.1	2.1	2.0	2.1	2.2	2.3
Total	**84.1**	**67.1**	**60.4**	**60.3**	**56.8**	**56.9**	**59.8**	**57.1**	**58.5**

Note: Totals may not sum due to independent rounding. Parentheses indicate negative values.

Table 3-27: CH_4 Emissions from Coal Mining (Gg)

Activity	1990	1995	2000	2001	2002	2003	2004	2005	2006
Underground Mining	2,968	2,226	1,875	1,820	1,692	1,715	1,813	1,675	1,709
Liberated	3,234	2,816	2,619	2,641	2,605	2,522	2,534	2,491	2,599
Recovered & Used	(266)	(591)	(744)	(821)	(913)	(807)	(721)	(815)	(891)
Surface Mining	574	548	586	627	610	592	616	633	668

Post-Mining (Underground)	368		330		318	325	305	306	317	306	298
Post-Mining (Surface)	93		89		95	102	99	96	100	103	109
Total	**4,003**		**3,193**		**2,874**	**2,874**	**2,707**	**2,709**	**2,846**	**2,717**	**2,784**

Note: Totals may not sum due to independent rounding. Parentheses indicate negative values.

Methodology

The methodology for estimating CH_4 emissions from coal mining consists of two parts. The first part involves estimating CH_4 emissions from underground mines. Because of the availability of ventilation system measurements, underground mine emissions can be estimated on a mine-by-mine basis and then summed to determine total emissions. The second step involves estimating emissions from surface mines and post-mining activities by multiplying basin-specific coal production by basin-specific emission factors.

Underground mines. Total CH_4 emitted from underground mines was estimated as the sum of CH_4 liberated from ventilation systems and CH_4 liberated by means of degasification systems, minus CH_4 recovered and used. The Mine Safety and Heath Administration (MSHA) samples CH_4 emissions from ventilation systems for all mines with detectable[40] CH_4 concentrations. These mine-by-mine measurements are used to estimate CH_4 emissions from ventilation systems.

Some of the higher-emitting underground mines also use degasification systems (e.g., wells or boreholes) that remove CH_4 before, during, or after mining. This CH_4 can then be collected for use or vented to the atmosphere. Various approaches were employed to estimate the quantity of CH_4 collected by each of the twenty mines using these systems, depending on available data. For example, some mines report to EPA the amount of CH_4 liberated from their degasification systems. For mines that sell recovered CH_4 to a pipeline, pipeline sales data published by state petroleum and natural gas agencies were used to estimate degasification emissions. For those mines for which no other data are available, default recovery efficiency values were developed, depending on the type of degasification system employed.

Finally, the amount of CH_4 recovered by degasification systems and then used (i.e., not vented) was estimated. In 2006, thirteen active coal mines sold recovered CH_4 into the local gas pipeline networks, while one coal mine used recovered CH_4 on site. Emissions avoided for these projects were estimated using gas sales data reported by various state agencies. For most mines with recovery systems, companies and state agencies provided individual well production information, which was used to assign gas sales to a particular year. For the few remaining mines, coal mine operators supplied information regarding the number of years in advance of mining that gas recovery occurs. In the case of Jim Walter Resources (JWR), the emissions avoided data was taken from the 1605b reports that the mining company has been filing with the Department of Energy (DOE) since 1991 as part of their Voluntary Reporting Program.

Surface Mines and Post-Mining Emissions. Surface mining and post-mining CH_4 emissions were estimated by multiplying basin-specific coal production, obtained from the Energy Information Administration's *Annual Coal Report* (see Table 3-28) (EIA 2006), by basin-specific emission factors. Surface mining emission factors were developed by assuming that surface mines emit two times as much CH_4 as the average *in situ* CH_4 content of the coal. Revised data on *in situ* CH_4 content and emissions factors are taken from EPA (2005), EPA (1996), and AAPG (1984). This calculation accounts for CH_4 released from the strata surrounding the coal seam. For post-mining emissions, the emission factor was assumed to be 32.5 percent of the average *in situ* CH_4 content of coals mined in the basin.

Table 3-28: Coal Production (Thousand Metric Tons)

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[40] MSHA records coal mine CH_4 readings with concentrations of greater than 50 ppm (parts per million) CH_4. Readings below this threshold are considered non-detectable.

Year	Underground	Surface	Total
1990	384,250	546,818	931,068
1995	359,477	577,638	937,115
2000	338,173	635,592	973,765
2001	345,305	676,142	1,021,446
2002	324,219	667,619	991,838
2003	320,047	651,251	971,297
2004	333,449	674,551	1,008,000
2005	334,404	691,460	1,025,864
2006	325,703	728,459	1,054,162

Uncertainty

A quantitative uncertainty analysis was conducted for the coal mining source category using the IPCC-recommended Tier 2 uncertainty estimation methodology. Because emission estimates from underground ventilation systems were based on actual measurement data, uncertainty is relatively low. A degree of imprecision was introduced because the measurements used were not continuous but rather an average of quarterly instantaneous readings. Additionally, the measurement equipment used can be expected to have resulted in an average of 10 percent overestimation of annual CH_4 emissions (Mutmansky and Wang 2000). Estimates of CH_4 recovered by degasification systems are relatively certain because many coal mine operators provided information on individual well gas sales and mined through dates. Many of the recovery estimates use data on wells within 100 feet of a mined area. Uncertainty also exists concerning the radius of influence of each well. The number of wells counted, and thus the avoided emissions, may vary if the drainage area is found to be larger or smaller than currently estimated.

Compared to underground mines, there is considerably more uncertainty associated with surface mining and post-mining emissions because of the difficulty in developing accurate emission factors from field measurements. However, since underground emissions comprise the majority of total coal mining emissions, the uncertainty associated with underground emissions is the primary factor that determines overall uncertainty. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-29. Coal mining CH_4 emissions in 2006 were estimated to be between 53.3 and 76.3 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 9 percent below to 30 percent above the 2006 emission estimate of 58.5 Tg CO_2 Eq.

Table 3-29: Tier 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Coal Mining (Tg CO_2 Eq. and Percent)

Source	Gas	2006 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a]			
			(Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Coal Mining	CH_4	58.5	53.3	76.3	-9%	+30%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

Recalculations Discussion

In 2006, recalculations of emissions avoided at three JWR coal mines in Alabama were performed as the mining company provided copies of their 1605b reports that they had been filing with DO. These reports cover the years 1991 through 2005. The 2006 report has not yet been filed, however JWR provided the 2006 data. In previous inventories, emissions avoided calculations for any pre-drainage wells at JWR coal mines were based on publicly-available data records from the Alabama State Oil & Gas Board. Emission reductions were calculated for pre-drainage wells located inside the mine plan boundaries and were declared "shut-in" by the O&G Board. The total production for a well was claimed in the year that the well was shut-in and mined through.

Secondly, the gas content values assigned to each coal basin in the surface mine emissions component of the inventory were changed to reflect recent work carried out by U.S. EPA (EPA 2005). This change for the 2006 inventory also impacted the reported emissions attributed to surface mining operations (active and post mining) for all past reported years (1990 – 2005), resulting in increased emission estimates for surface and post-surface mining operations for all reported years.

Finally, the conversion factor used previously to convert from mmcf of methane to Gg of CH_4 was 52,150 (1990 – 2005). The conversion factor used in the natural gas emissions inventory is 51,921. In order to ensure consistency of emissions estimates across the inventory, the conversion factor for the active mines inventory was changed to 51,921. This change impacted all previous year's inventories for the values calculated and reported for Gg of methane emitted, and for Tg of CO_2 Eq. emitted. The difference between these factors is 0.44 percent.

3.6. Abandoned Underground Coal Mines (IPCC Source Category 1B1a)

Underground coal mines contribute the largest share of CH_4 emissions, with active underground mines the leading source of underground emissions. However, mines also continue to release CH_4 after closure. As mines mature and coal seams are mined through, mines are closed and abandoned. Many are sealed and some flood through intrusion of groundwater or surface water into the void. Shafts or portals are generally filled with gravel and capped with a concrete seal, while vent pipes and boreholes are plugged in a manner similar to oil and gas wells. Some abandoned mines are vented to the atmosphere to prevent the buildup of CH_4 that may find its way to surface structures through overburden fractures. As work stops within the mines, the CH_4 liberation decreases but it does not stop completely. Following an initial decline, abandoned mines can liberate CH_4 at a near-steady rate over an extended period of time, or, if flooded, produce gas for only a few years. The gas can migrate to the surface through the conduits described above, particularly if they have not been sealed adequately. In addition, diffuse emissions can occur when CH_4 migrates to the surface through cracks and fissures in the strata overlying the coal mine. The following factors influence abandoned mine emissions:

- Time since abandonment;
- Gas content and adsorption characteristics of coal;
- CH_4 flow capacity of the mine;
- Mine flooding;
- Presence of vent holes; and
- Mine seals.

Gross abandoned mine CH_4 emissions ranged from 6.0 to 9.1 Tg CO_2 Eq. from 1990 through 2006, varying, in general, by less than 1 to approximately 19 percent from year to year. Fluctuations were due mainly to the number of mines closed during a given year as well as the magnitude of the emissions from those mines when active. Gross abandoned mine emissions peaked in 1996 (9.1 Tg CO_2 Eq.) due to the large number of mine closures from 1994 to 1996 (70 gassy mines closed during the three-year period). In spite of this rapid rise, abandoned mine emissions have been generally on the decline since 1996. There were fewer than fifteen gassy mine closures during each of the years from 1998 through 2006, with only one closure in 2006. By 2006, gross abandoned mine emissions declined to 6.8 Tg CO_2 Eq. (see Table 3-30 and Table 3-31). Gross emissions are reduced by methane recovered and used at 20 mines, resulting in net emissions in 2006 of 5.4 Tg CO_2Eq.

Table 3-30: CH_4 Emissions from Abandoned Coal Mines (Tg CO_2 Eq.)

Activity	1990		1995		2000	2001	2002	2003	2004	2005	2006
Abandoned Underground Mines	6.0		8.9		8.9	8.2	7.7	7.5	7.3	7.0	6.8
Recovered & Used	0.0		0.7		1.5	1.5	1.6	1.5	1.5	1.4	1.4
Total	**6.0**		**8.2**		**7.4**	**6.7**	**6.2**	**6.0**	**5.8**	**5.6**	**5.4**

Note: Totals may not sum due to independent rounding.

Table 3-31: CH_4 Emissions from Abandoned Coal Mines (Gg)

Activity	1990		1995		2000	2001	2002	2003	2004	2005	2006
Abandoned Underground Mines	288		424		422	389	368	356	347	333	322
Recovered & Used	0		32		72	70	75	72	71	68	65
Total	288		392		350	319	293	284	276	265	257

Note: Totals may not sum due to independent rounding.

Methodology

Estimating CH_4 emissions from an abandoned coal mine requires predicting the emissions of a mine from the time of abandonment through the inventory year of interest. The flow of CH_4 from the coal to the mine void is primarily dependent on the mine's emissions when active and the extent to which the mine is flooded or sealed. The CH_4 emission rate before abandonment reflects the gas content of the coal, rate of coal mining, and the flow capacity of the mine in much the same way as the initial rate of a water-free conventional gas well reflects the gas content of the producing formation and the flow capacity of the well. A well or a mine which produces gas from a coal seam and the surrounding strata will produce less gas through time as the reservoir of gas is depleted. Depletion of a reservoir will follow a predictable pattern depending on the interplay of a variety of natural physical conditions imposed on the reservoir. The depletion of a reservoir is commonly modeled by mathematical equations and mapped as a type curve. Type curves which are referred to as decline curves have been developed for abandoned coal mines. Existing data on abandoned mine emissions through time, although sparse, appear to fit the hyperbolic type of decline curve used in forecasting production from natural gas wells.

In order to estimate CH_4 emissions over time for a given mine, it is necessary to apply a decline function, initiated upon abandonment, to that mine. In the analysis, mines were grouped by coal basin with the assumption that they will generally have the same initial pressures, permeability and isotherm. As CH_4 leaves the system, the reservoir pressure, P_r, declines as described by the isotherm. The emission rate declines because the mine pressure (P_w) is essentially constant at atmospheric pressure, for a vented mine, and the PI term is essentially constant at the pressures of interest (atmospheric to 30 psia). A rate-time equation can be generated that can be used to predict future emissions. This decline through time is hyperbolic in nature and can be empirically expressed as:

$$q = q_i \, (1+bD_i t)^{(-1/b)}$$

where,

q = Gas rate at time t in mmcf/d

q_i = Initial gas rate at time zero (t_o) in million cubic feet per day mmcfd)

b = The hyperbolic exponent, dimensionless

D_i = Initial decline rate, 1/yr

t = Elapsed time from t_o (years)

This equation is applied to mines of various initial emission rates that have similar initial pressures, permeability and adsorption isotherms (EPA 2003).

The decline curves created to model the gas emission rate of coal mines must account for factors that decrease the rate of emission after mining activities cease, such as sealing and flooding. Based on field measurement data, it was assumed that most U.S. mines prone to flooding will become completely flooded within eight years and therefore no longer have any measurable CH_4 emissions. Based on this assumption, an average decline rate for flooding mines was established by fitting a decline curve to emissions from field measurements. An exponential equation was developed from emissions data measured at eight abandoned mines known to be filling with water located in two of the five basins. Using a least squares, curve-fitting algorithm, emissions data were matched to the exponential

equation shown below. There was not enough data to establish basin-specific equations as was done with the vented, non-flooding mines (EPA 2003).

$$q = q_i e^{(-Dt)}$$

where,

q = Gas flow rate at time t in mcf/d

q_i = Initial gas flow rate at time zero (t_o) in mcfd

D = Decline rate, 1/yr

t = Elapsed time from t_o (years)

Seals have an inhibiting effect on the rate of flow of CH_4 into the atmosphere compared to the rate that would be emitted if the mine had an open vent. The total volume emitted will be the same, but will occur over a longer period. The methodology, therefore, treats the emissions prediction from a sealed mine similar to emissions from a vented mine, but uses a lower initial rate depending on the degree of sealing. The computational fluid dynamics simulator was again used with the conceptual abandoned mine model to predict the decline curve for inhibited flow. The percent sealed is defined as $100 \times (1 - $ (initial emissions from sealed mine / emission rate at abandonment prior to sealing)). Significant differences are seen between 50 percent, 80 percent and 95 percent closure. These decline curves were therefore used as the high, middle, and low values for emissions from sealed mines (EPA 2003).

For active coal mines, those mines producing over 100 mcfd account for 98 percent of all CH_4 emissions. This same relationship is assumed for abandoned mines. It was determined that 441 abandoned mines closing after 1972 produced emissions greater than 100 mcfd when active. Further, the status of 264 of the 441 mines (or 60 percent) is known to be either: 1.) vented to the atmosphere; 2.) sealed to some degree (either earthen or concrete seals); or, 3.) flooded (enough to inhibit CH_4 flow to the atmosphere). The remaining 40 percent of the mines were placed in one of the three categories by applying a probability distribution analysis based on the known status of other mines located in the same coal basin (EPA 2003).

Table 3-32: Number of gassy abandoned mines occurring in U.S. basins grouped by class according to post-abandonment state

Basin	Sealed	Vented	Flooded	Total Known	Unknown	Total Mines
Central Appl.	23	25	48	96	111	207
Illinois	28	3	14	45	25	70
Northern Appl.	41	22	16	79	32	111
Warrior Basin	0	0	14	14	0	14
Western Basins	25	3	2	30	9	39
Total	**117**	**53**	**94**	**264**	**177**	**441**

Inputs to the decline equation require the average emission rate and the date of abandonment. Generally this data is available for mines abandoned after 1972; however, such data are largely unknown for mines closed before 1972. Information that is readily available such as coal production by state and county are helpful, but do not provide enough data to directly employ the methodology used to calculate emissions from mines abandoned after 1971. It is assumed that pre-1972 mines are governed by the same physical, geologic, and hydrologic constraints that apply to post-1972 mines; thus, their emissions may be characterized by the same decline curves.

During the 1970s, 78 percent of CH_4 emissions from coal mining came from seventeen counties in seven states. In addition, mine closure dates were obtained for two states, Colorado and Illinois, for the hundred year period extending from 1900 through 1999. The data were used to establish a frequency of mine closure histogram (by decade) and applied to the other five states with gassy mine closures. As a result, basin-specific decline curve equations were applied to 145 gassy coal mines estimated to have closed between 1920 and 1971 in the United

States, representing 78 percent of the emissions. State-specific, initial emission rates were used based on average coal mine CH_4 emissions rates during the 1970s (EPA 2003).

Abandoned mines emission estimates are based on all closed mines known to have active mine CH_4 ventilation emission rates greater than 100 mcfd at the time of abandonment. For example, for 1990 the analysis included 145 mines closed before 1972 and 258 mines closed between 1972 and 1990. Initial emission rates based on MSHA reports, time of abandonment, and basin-specific decline curves influenced by a number of factors were used to calculate annual emissions for each mine in the database. Coal mine degasification data are not available for years prior to 1990, thus the initial emission rates used reflect ventilation emissions only for pre-1990 closures. CH_4 degasification amounts were added to the quantity of CH_4 ventilated for the total CH_4 liberation rate for fifteen mines that closed between 1992 and 2006. Since the sample of gassy mines (with active mine emissions greater than 100 mcfd) is assumed to account for 78 percent of the pre-1971 and 98 percent of the post-1971 abandoned mine emissions, the modeled results were multiplied by 1.22 and 1.02 to account for all U.S. abandoned mine emissions.

From 1993 through 2006, emission totals were downwardly adjusted to reflect abandoned mine CH_4 emissions avoided from those mines. The inventory totals were not adjusted for abandoned mine reductions in 1990 through 1992, because no data was reported for abandoned coal mining CH_4 recovery projects during that time.

Uncertainty

A quantitative uncertainty analysis was conducted to estimate the uncertainty surrounding the estimates of emissions from abandoned underground coal mines. The uncertainty analysis described below provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. The results provide the range within which, with 95 percent certainty, emissions from this source category are likely to fall.

As discussed above, the parameters for which values must be estimated for each mine in order to predict its decline curve are: 1) the coal's adsorption isotherm; 2) CH_4 flow capacity as expressed by permeability; and 3) pressure at abandonment. Because these parameters are not available for each mine, a methodological approach to estimating emissions was used that generates a probability distribution of potential outcomes based on the most likely value and the probable range of values for each parameter. The range of values is not meant to capture the extreme values, but values that represent the highest and lowest quartile of the cumulative probability density function of each parameter. Once the low, mid, and high values are selected, they are applied to a probability density function.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-33. Abandoned coal mines CH_4 emissions in 2006 were estimated to be between 4.5 and 6.4 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 17 percent below to 19 percent above the 2006 emission estimate of 5.4 Tg CO_2 Eq. One of the reasons for the relatively narrow range is that mine-specific data is used in the methodology. The largest degree of uncertainty is associated with the unknown status mines (which account for 40 percent of the mines), with a ±50 percent uncertainty.

Table 3-33: Tier 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Abandoned Underground Coal Mines (Tg CO_2 Eq. and Percent)

Source	Gas	2006 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a]			
			(Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Abandoned Underground Coal Mines	CH_4	5.4	4.5	6.4	-17%	+19%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

3.7. Natural Gas Systems (IPCC Source Category 1B2b)

The U.S. natural gas system encompasses hundreds of thousands of wells, hundreds of processing facilities, and over a million miles of transmission and distribution pipelines. Overall, natural gas systems emitted 102.4 Tg CO_2 Eq. (4,877 Gg) of CH_4 in 2006, an 18 percent decrease over 1990 emissions (see Table 3-34 and Table 3-35), and 28.5 Tg CO_2 Eq. (28,504Gg) of non-combustion CO_2 in 2006, a 15 percent decrease over 1990 emissions (see Table 3-36 and Table 3-37). Improvements in management practices and technology, along with the replacement of older equipment, have helped to stabilize emissions.

CH_4 and non-combustion CO_2 emissions from natural gas systems are generally process related, with normal operations, routine maintenance, and system upsets being the primary contributors. Emissions from normal operations include: natural gas engines and turbine uncombusted exhaust, bleed and discharge emissions from pneumatic devices, and fugitive emissions from system components. Routine maintenance emissions originate from pipelines, equipment, and wells during repair and maintenance activities. Pressure surge relief systems and accidents can lead to system upset emissions. Below is a characterization of the four major stages of the natural gas system. Each of the stages is described and the different factors affecting CH_4 and non-combustion CO_2 emissions are discussed.

Field Production. In this initial stage, wells are used to withdraw raw gas from underground formations. Emissions arise from the wells themselves, gathering pipelines, and well-site gas treatment facilities such as dehydrators and separators. Fugitive emissions and emissions from pneumatic devices account for the majority of CH_4 emissions. Flaring emissions account for the majority of the non-combustion CO_2 emissions. Emissions from field production accounted for approximately 27 percent of CH_4 emissions and about 25 percent of non-combustion CO_2 emissions from natural gas systems in 2006.

Processing. In this stage, natural gas liquids and various other constituents from the raw gas are removed, resulting in "pipeline quality" gas, which is injected into the transmission system. Fugitive CH_4 emissions from compressors, including compressor seals, are the primary emission source from this stage. The majority of non-combustion CO_2 emissions come from acid gas removal units, which are designed to remove CO_2 from natural gas. Processing plants account for about 12 percent of CH_4 emissions and approximately 74 percent of non-combustion CO_2 emissions from natural gas systems.

Transmission and Storage. Natural gas transmission involves high pressure, large diameter pipelines that transport gas long distances from field production and processing areas to distribution systems or large volume customers such as power plants or chemical plants. Compressor station facilities, which contain large reciprocating and turbine compressors, are used to move the gas throughout the United States transmission system. Fugitive CH_4 emissions from these compressor stations and from metering and regulating stations account for the majority of the emissions from this stage. Pneumatic devices and engine uncombusted exhaust are also sources of CH_4 emissions from transmission facilities.

Natural gas is also injected and stored in underground formations, or liquefied and stored in above ground tanks, during periods of low demand (e.g., summer), and withdrawn, processed, and distributed during periods of high demand (e.g., winter). Compressors and dehydrators are the primary contributors to emissions from these storage facilities. CH_4 emissions from the transmission and storage sector account for approximately 37 percent of emissions from natural gas systems, while CO_2 emissions from transmission and storage account for less than 1 percent of the non-combustion CO_2 emissions from natural gas systems.

Distribution. Distribution pipelines take the high-pressure gas from the transmission system at "city gate" stations, reduce the pressure and distribute the gas through primarily underground mains and service lines to individual end users. There were over 1,250,000 miles of distribution mains in 2006, an increase from just over 947,000 miles in 1990 (OPS 2007b). Distribution system emissions, which account for approximately 24 percent of CH_4 emissions

from natural gas systems and less than 1 percent of non-combustion CO_2 emissions, result mainly from fugitive emissions from gate stations and pipelines.[41] An increased use of plastic piping, which has lower emissions than other pipe materials, has reduced emissions from this stage. Distribution system CH_4 emissions in 2006 were 20 percent lower than 1990 levels.

Table 3-34. CH_4 Emissions from Natural Gas Systems (Tg CO_2 Eq.)*

Stage	1990	1995	2000	2001	2002	2003	2004	2005	2006
Field Production	32.7	37.2	38.8	41.5	42.5	40.1	32.9	25.0	27.6
Processing	14.9	14.9	14.6	14.7	14.2	13.6	13.4	11.8	11.9
Transmission and Storage	46.3	45.8	43.8	40.7	42.4	42.8	40.9	38.5	38.2
Distribution	30.8	30.1	29.3	28.5	25.8	26.9	26.8	27.2	24.7
Total	**124.7**	**128.1**	**126.5**	**125.3**	**124.9**	**123.3**	**114.0**	**102.5**	**102.4**

*Including CH_4 emission reductions achieved by the Natural Gas STAR program and NESHAP regulations.
Note: Totals may not sum due to independent rounding.

Table 3-35. CH_4 Emissions from Natural Gas Systems (Gg)*

Stage	1990	1995	2000	2001	2002	2003	2004	2005	2006
Field Production	1,555	1,774	1,849	1,976	2,024	1,909	1,566	1,190	1,317
Processing	707	711	693	699	675	646	639	560	568
Transmission and Storage	2,206	2,181	2,087	1,936	2,019	2,039	1,947	1,834	1,817
Distribution	1,468	1,432	1,395	1,356	1,228	1,279	1,275	1,296	1,176
Total	**5,937**	**6,098**	**6,024**	**5,968**	**5,946**	**5,874**	**5,426**	**4,880**	**4,877**

*Including CH_4 emission reductions achieved by the Natural Gas STAR program and NESHAP regulations.
Note: Totals may not sum due to independent rounding.

Table 3-36. Non-combustion CO_2 Emissions from Natural Gas Systems (Tg CO_2 Eq.)

Stage	1990	1995	2000	2001	2002	2003	2004	2005	2006
Field Production	5.9	9.1	6.0	6.3	6.5	6.3	6.2	7.6	7.2
Processing	27.8	24.6	23.3	22.4	23.1	22.0	21.8	21.7	21.2
Transmission and Storage	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Distribution	+	+	+	+	+	+	+	+	+
Total	**33.7**	**33.8**	**29.4**	**28.8**	**29.6**	**28.4**	**28.1**	**29.5**	**28.5**

Note: Totals may not sum due to independent rounding.

Table 3-37. Non-combustion CO_2 Emissions from Natural Gas Systems (Gg)

Stage	1990	1995	2000	2001	2002	2003	2004	2005	2006
Field Production	5,876	9,083	5,956	6,307	6,463	6,342	6,242	7,627	7,203
Processing	27,752	24,621	23,333	22,387	23,066	22,002	21,780	21,736	21,204
Transmission and Storage	58	60	60	59	61	61	61	60	59
Distribution	42	42	41	40	40	40	40	39	37
Total	**33,729**	**33,806**	**29,390**	**28,793**	**29,629**	**28,445**	**28,122**	**29,462**	**28,504**

Note: Totals may not sum due to independent rounding.

Methodology

The primary basis for estimates of CH_4 and non-combustion-related CO_2 emissions from the U.S. natural gas industry is a detailed study by the Gas Research Institute and EPA (EPA/GRI 1996). The EPA/GRI study developed over 80 CH_4 emission and activity factors to characterize emissions from the various components within the operating stages of the U.S. natural gas system. The same activity factors were used to estimate both CH_4 and

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[41] The percentages of total emissions from each stage may not sum to 100 percent due to independent rounding.

non-combustion CO_2 emissions. However, the CH_4 emission factors were adjusted for CO_2 content when estimating fugitive and vented non-combustion CO_2 emissions. The EPA/GRI study was based on a combination of process engineering studies and measurements at representative gas facilities. From this analysis, a 1992 emission estimate was developed using the emission and activity factors. For other years, a set of industry activity factor drivers was developed that can be used to update activity factors. These drivers include statistics on gas production, number of wells, system throughput, miles of various kinds of pipe, and other statistics that characterize the changes in the U.S. natural gas system infrastructure and operations.

See Annex 3.4 for more detailed information on the methodology and data used to calculate CH_4 and non-combustion CO_2 emissions from natural gas systems.

Activity factor data were taken from the following sources: American Gas Association (AGA 1991 through 1998); Minerals and Management Service (MMS 2007a-e); Monthly Energy Review (EIA 2007f); Natural Gas Liquids Reserves Report (EIA 2005); Natural Gas Monthly (EIA 2007b,c,e); the Natural Gas STAR Program annual emissions savings (EPA 2007); Oil and Gas Journal (OGJ 1997 through 2007); Office of Pipeline Safety (OPS 2007a-b) and other Energy Information Administration publications (EIA 2001, 2004, 2007a,d); World Oil Magazine (2007a-b). Data for estimating emissions from hydrocarbon production tanks is incorporated (EPA 1999). Coalbed CH_4 well activity factors were taken from the Wyoming Oil and Gas Conservation Commission (Wyoming 2007) and the Alabama State Oil and Gas Board (Alabama 2007). Other state well data was taken from: American Association of Petroleum Geologists (AAPG 2004); Brookhaven College (Brookhaven 2004); Kansas Geological Survey (Kansas 2007); Montana Board of Oil and Gas Conservation (Montana 2007); Oklahoma Geological Survey (Oklahoma 2007); Morgan Stanley (Morgan Stanley 2005); Rocky Mountain Production Report (Lippman (2003); New Mexico Oil Conservation Division (New Mexico 2007a,b); Texas Railroad Commission (Texas 2007a-d); Utah Division of Oil, Gas and Mining (Utah 2007). Emission factors were taken from EPA/GRI (1996). GTI's Unconventional Natural Gas and Gas Composition Databases (GTI 2001) were used to adapt the CH_4 emission factors into non-combustion related CO_2 emission factors. Additional information about CO_2 content in transmission quality natural gas was obtained via the internet from numerous U.S. transmission companies to help further develop the non-combustion CO_2 emission factors.

Uncertainty

A quantitative uncertainty analysis was conducted to determine the level of uncertainty surrounding estimates of emissions from natural gas systems. Performed using @RISK software and the IPCC-recommended Tier 2 methodology (Monte Carlo Simulation technique), this analysis provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. The results presented below provide with 95 percent certainty the range within which emissions from this source category are likely to fall.

The heterogeneous nature of the natural gas industry makes it difficult to sample facilities that are completely representative of the entire industry. Because of this, scaling up from model facilities introduces a degree of uncertainty. Additionally, highly variable emission rates were measured among many system components, making the calculated average emission rates uncertain. The results of the Tier 2 quantitative uncertainty analysis is summarized in Table 3-38. Natural gas systems CH_4 emissions in 2006 were estimated to be between 79.1 and 148.4 Tg CO_2 Eq. at a 95 percent confidence level. Natural gas systems non-combustion CO_2 emissions in 2006 were estimated to be between 22.0 and 41.3 Tg CO_2 Eq. at 95 percent confidence level.

Table 3-38: Tier 2 Quantitative Uncertainty Estimates for CH_4 and Non-combustion CO_2 Emissions from Natural Gas Systems (Tg CO_2 Eq. and Percent)

Source	Gas	2006 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a]			
			(Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Natural Gas Systems	CH_4	102.4	79.1	148.4	-23%	+45%

Natural Gas Systems[b]	CO_2	28.5	22.0	41.3	-23%	+45%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.
[b] An uncertainty analysis for the non-combustion CO_2 emissions was not performed. The relative uncertainty estimated (expressed as a percent) from the CH_4 uncertainty analysis was applied to the point estimate of non-combustion CO_2 emissions.

Recalculations Discussion

Offshore oil and gas platform counts are driven by the percentage of total platforms that are located on oil and gas fields, respectively, as identified by MMS. This percentage can be calculated from MMS (2007a,b,e) for years 2003 onward. For year 1992, the estimate was provided by MMS by direct communication. The oil platform count for years 1990, 1991, and 1993 through 2002 are driven by a linear projection based on known platform counts in 1992 and 2003. A miscalculation in year 2003 for oil platform count was re-estimated, which caused the entire time series prior to year 2003 (except 1992) to change. This change resulted in a reallocation of platform counts to the natural gas and petroleum models. The total number of offshore platforms, both oil and gas, used as drivers remained the same. The effects of this recalculation are most significant in 1990, with an absolute difference of 31 Gg; less significant changes occurred in all subsequent years.

The second recalculation is a result of changing several base year (1992) activity factor and emissions factor data to the exact values from the EPA/GRI 1996 report. These changes were small and the effects were an increase of less than 1 percent in 1992 CH_4 emissions.

A third recalculation is the result of updating previous years' activity and Natural Gas STAR reduction values with revised data. This is especially evident in 2005, where the revised reductions data reports an additional 443 Gg of reductions totaled from all four sectors; decreasing total 2005 emission estimates by nearly 9.5 percent.

QA/QC and Verification Discussion

A tier 2 QA/QC analysis was undertaken to examine why emissions from small reciprocating compressors are lower in the production sector than in other sectors of the natural gas industry. The emission factor for these compressors is based on EPA/GRI 1996. Background information from EPA/GRI 1996, along with information from the Natural Gas STAR program was analyzed and it was determined that the emission factor for small compressors in the eastern United States (U.S. East) was significantly lower than the emission factor developed for the western area of the country (U.S. West). Details of the emission factor development revealed that the U.S. East emission factor in EPA/GRI 1996 does not include fugitives from compressor seals and pressure relief valves. Experience from the Natural Gas STAR Program demonstrates that seal leakage from rod packing is the largest source of fugitive emissions from reciprocating compressors. To account for compressor seal leakage, the U.S. West emission factor was used for the entire United States for 1990 through 2006. These updated emission factors are an interim improvement and further research is underway to compare these updated emissions factors with recent vendor data.

Planned Improvements

Currently, activity factors for most sources in the natural gas inventory are dependent on EPA/GRI 1996 estimates of activity data in base year 1992. The activity factors for all years other than the base year are estimated from the base year activity data and are driven by an appropriate activity driver. However, in some instances activity data are directly available from published sources and there is no need to derive the current year activity data through the use of drivers. Research is underway to determine the feasibility of using published activity data, where available, and whether this would impact any of the emission factors currently used.

Separately, work has been initiated to update select emission factors from the earlier study. Where relevant, these emission factors will be incorporated into the inventory when they become available.

As noted above, additional research will be undertaken to evaluate, and as necessary refine, the emission factor for small reciprocating compressors in the U.S. West region.

3.8. Petroleum Systems (IPCC Source Category 1B2a)

CH_4 emissions from petroleum systems are primarily associated with crude oil production, transportation, and refining operations. During each of these activities, CH_4 emissions are released to the atmosphere as fugitive emissions, vented emissions, emissions from operational upsets, and emissions from fuel combustion. Fugitive and vented CO_2 emissions from petroleum systems are primarily associated with crude oil production and are negligible in the transportation and refining operations. Combusted CO_2 emissions are already accounted for in the Fossil Fuels Combustion calculations previously discussed, and hence have not been taken into account in this inventory. Total CH_4 and CO_2 emissions from petroleum systems in 2006 were 28.4 Tg CO_2 Eq. (1,354 Gg CH_4) and 0.3 Tg CO_2 (293 Gg) respectively. Since 1990, CH_4 emissions have declined by 16 percent, due to industry efforts to reduce emissions and a decline in domestic oil production (see Table 3-39, Table 3-40, Table 3-41, and Table 3-42). CO_2 emissions have also declined by 22 percent since 1990 due to similar reasons.

Production Field Operations. Production field operations account for over 97 percent of total CH_4 emissions from petroleum systems. Vented CH_4 from field operations account for over 91 percent of the emissions from the production sector, unburned CH_4 combustion emissions account for 5.2 percent, fugitive emissions are 3.4 percent, and process upset emissions, slightly over one-tenth of a percent. The most dominant sources of emissions, in the order of magnitude, are shallow water offshore oil platforms, natural-gas-powered pneumatic devices (low bleed and high bleed), field storage tanks, gas engines, chemical injection pumps and deep water offshore platforms. These seven sources alone emit over 95 percent of the production field operations emissions. Offshore platform emissions are a combination of fugitive, vented, and unburned fuel combustion emissions from all equipment housed on oil platforms producing oil and associated gas. Emissions from high and low-bleed pneumatics occur when pressurized gas that is used for control devices is bled to the atmosphere as they cycle open and closed to modulate the system. Emissions from storage tanks occur when the CH_4 entrained in crude oil under pressure volatilizes once the crude oil is put into storage tanks at atmospheric pressure. Emissions from gas engines are due to unburned CH_4 that vents with the exhaust. Emissions from chemical injection pumps are due to the 25 percent that use associated gas to drive pneumatic pumps. The remaining five percent of the emissions are distributed among 26 additional activities within the four categories: vented, fugitive, combustion and process upset emissions. For more detailed, source-level, data on methane emissions in production field operations refer to Annex 3.5.

Vented CO_2 associated with natural gas emissions from field operations account for 99 percent of the total CO_2 emissions, while fugitive and process upsets together account for 1 percent of the emissions. The most dominant sources of vented emissions are field storage tanks, pneumatic devices (high bleed and low bleed), shallow water offshore oil platforms, and chemical injection pumps. These five sources together account for 98.5 percent of the non-combustion CO_2 emissions while the remaining 1.5 percent of the emissions is distributed among 24 additional activities within the three categories: vented, fugitive and process upsets.

Crude Oil Transportation. Crude oil transportation activities account for less than one half of one percent of total CH_4 emissions from the oil industry. Venting from tanks and marine vessel loading operations accounts for 64 percent of CH_4 emissions from crude oil transportation. Fugitive emissions, almost entirely from floating roof tanks, account for 19 percent. The remaining 17 percent is distributed among six additional sources within these two categories. Emissions from pump engine drivers and heaters were not estimated due to lack of data.

Crude Oil Refining. Crude oil refining processes and systems account for slightly over two percent of total CH_4 emissions from the oil industry because most of the CH_4 in crude oil is removed or escapes before the crude oil is delivered to the refineries. There is an insignificant amount of CH_4 in all refined products. Within refineries, vented emissions account for about 87 percent of the emissions, while fugitive and combustion emissions account for approximately six and seven percent, respectively. Refinery system blowdowns for maintenance and the process of asphalt blowing—with air, to harden the asphalt—are the primary venting contributors. Most of the fugitive CH_4 emissions from refineries are from leaks in the fuel gas system. Refinery combustion emissions include small amounts of unburned CH_4 in process heater stack emissions and unburned CH_4 in engine exhausts and flares.

Table 3-39: CH_4 Emissions from Petroleum Systems (Tg CO_2 Eq.)

Activity	1990		1995		2000	2001	2002	2003	2004	2005	2006
Production Field Operations	33.2		31.3		29.6	29.5	29.2	28.5	28.0	27.6	27.7

	1990	1995	2000	2001	2002	2003	2004	2005	2006
Pneumatic device venting	10.3	9.7	9.0	8.9	8.9	8.7	8.6	8.3	8.4
Tank venting	3.8	3.4	3.2	3.2	3.2	3.1	3.0	2.8	2.9
Combustion & process upsets	1.9	1.7	1.6	1.6	1.6	1.5	1.5	1.5	1.5
Misc. venting & fugitives	16.8	16.0	15.3	15.3	15.1	14.7	14.5	14.5	14.5
Wellhead fugitives	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.4	0.4
Crude Oil Transportation	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Refining	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Total	**33.9**	**32.0**	**30.3**	**30.2**	**29.9**	**29.2**	**28.7**	**28.3**	**28.4**

Note: Totals may not sum due to independent rounding.

Table 3-40: CH_4 Emissions from Petroleum Systems (Gg)

Activity	1990	1995	2000	2001	2002	2003	2004	2005	2006
Production Field Operations	1,581	1,493	1,409	1,404	1,390	1,357	1,335	1,314	1,321
Pneumatic device venting	489	463	428	425	424	412	408	397	399
Tank venting	179	161	154	154	151	150	142	135	138
Combustion & process upsets	88	82	76	75	75	73	72	71	72
Misc. venting & fugitives	799	762	728	727	717	701	692	691	693
Wellhead fugitives	26	25	22	22	23	22	21	20	20
Crude Oil Transportation	7	6	5	5	5	5	5	5	5
Refining	25	25	28	27	27	27	28	28	28
Total	**1,612**	**1,524**	**1,442**	**1,436**	**1,422**	**1,390**	**1,368**	**1,346**	**1,354**

Note: Totals may not sum due to independent rounding.

Table 3-41: CO_2 Emissions from Petroleum Systems (Tg CO2 Eq.)

Activity	1990	1995	2000	2001	2002	2003	2004	2005	2006
Production Field Operations	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Pneumatic device venting	+	+	+	+	+	+	+	+	+
Tank venting	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.3
Misc. venting & fugitives	+	+	+	+	+	+	+	+	+
Wellhead fugitives	+	+	+	+	+	+	+	+	+
Total	**0.4**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**

+ Does not exceed 0.05 Tg CO_2 Eq.

Table 3-42: CO_2 Emissions from Petroleum Systems (Gg)

Activity	1990	1995	2000	2001	2002	2003	2004	2005	2006
Production Field Operations	376	341	325	325	320	316	302	287	293
Pneumatic device venting	27	26	24	24	24	23	23	22	22
Tank venting	328	296	283	283	278	276	262	248	253
Misc. venting & fugitives	18	18	17	17	16	16	16	16	16
Wellhead fugitives	1	1	1	1	1	1	1	1	1
Total	**376**	**341**	**325**	**325**	**320**	**316**	**302**	**287**	**293**

Note: Totals may not sum due to independent rounding.

Methodology

The methodology for estimating CH_4 emissions from petroleum systems is a bottom-up approach, based on comprehensive studies of CH_4 emissions from U.S. petroleum systems (EPA 1996, EPA 1999). These studies combined emission estimates from 64 activities occurring in petroleum systems from the oil wellhead through crude oil refining, including 33 activities for crude oil production field operations, 11 for crude oil transportation activities, and 20 for refining operations. Annex 3.5 provides greater detail on the emission estimates for these 64 activities. The estimates of CH_4 emissions from petroleum systems do not include emissions downstream of oil refineries because these emissions are very small compared to CH_4 emissions upstream of oil refineries.

The methodology for estimating CH_4 emissions from the 64 oil industry activities employs emission factors initially developed by EPA (1999) and activity factors that are based on two EPA studies (1996, 1999) and EPA (2005). Emissions are estimated for each activity by multiplying emission factors (e.g., emission rate per equipment item or per activity) by their corresponding activity factor (e.g., equipment count or frequency of activity). The report provides emission factors and activity factors for all activities except those related to offshore oil production and field storage tanks. For offshore oil production, two emission factors were calculated using data collected over a one-year period for all federal offshore platforms (EPA 2005, MMS 2004). One emission factor is for oil platforms in shallow water, and one emission factor is for oil platforms in deep water. Emission factors are held constant for the period 1990 through 2006. The number of platforms in shallow water and the number of platforms in deep water are used as activity factors and are taken from Minerals Management Service statistics (MMS 2007a-c). For oil storage tanks, the emissions factor was calculated from API TankCalc data as the total emissions per barrel of crude charge (EPA 1999).

The methodology for estimating CO_2 emissions from petroleum systems combines vented, fugitive and process upset emissions sources from 29 activities for crude oil production field operations. Emissions are estimated for each activity by multiplying emission factors by their corresponding activity factors. The emission factors for CO_2 are estimated by multiplying the CH_4 emission factors by a conversion factor, which is the ratio of CO_2 content and methane content in produced associated gas. The only exceptions to this methodology are the emission factors for crude oil storage tanks which are obtained from API TankCalc simulation runs.

Activity factors for years 1990 through 2006 were collected from a wide variety of statistical resources. For some years, complete activity factor data were not available. In such cases, one of three approaches was employed. Where appropriate, the activity factor was calculated from related statistics using ratios developed for EPA (1996). For example, EPA (1996) found that the number of heater treaters (a source of CH_4 emissions) is related to both number of producing wells and annual production. To estimate the activity factor for heater treaters, reported statistics for wells and production were used, along with the ratios developed for EPA (1996). In other cases, the activity factor was held constant from 1990 through 2006 based on EPA (1999). Lastly, the previous year's data were used when data for the current year were unavailable. The CH_4 and CO_2 sources in the production sector share common activity factors. See Annex 3.5 for additional detail.

Nearly all emission factors were taken from EPA (1995, 1996, 1999). The remaining emission factors were taken from EPA default values in (EPA 2005) and the consensus of industry peer review panels.

Among the more important references used to obtain activity factors are the Energy Information Administration annual and monthly reports (EIA 1990 through 2006, 1990 through 2007, 1995 through 2007a-b), *Methane Emissions from the Natural Gas Industry* by the Gas Research Institute and EPA (EPA/GRI 1996a-d), *Estimates of Methane Emissions from the U.S. Oil Industry* (EPA 1999), consensus of industry peer review panels, MMS reports (MMS 2001, 2007a-c), analysis of MMS data (EPA 2005, MMS 2004), the *Oil & Gas Journal* (OGJ 2007a,b), the Interstate Oil and Gas Compact Commission (IOGCC 2007), and the United States Army Corps of Engineers (1995-2005).

Uncertainty

This section describes the analysis conducted to quantify uncertainty associated with the estimates of emissions from petroleum systems. Performed using @RISK software and the IPCC-recommended Tier 2 methodology (Monte Carlo Simulation technique), the method employed provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. The results provide the range within which, with 95 percent certainty, emissions from this source category are likely to fall.

The detailed, bottom-up inventory analysis used to evaluate U.S. petroleum systems reduces the uncertainty related to the CH_4 emission estimates in comparison with a top-down approach. However, some uncertainty still remains. Emission factors and activity factors are based on a combination of measurements, equipment design data, engineering calculations and studies, surveys of selected facilities and statistical reporting. Statistical uncertainties arise from natural variation in measurements, equipment types, operational variability and survey and statistical

methodologies. Published activity factors are not available every year for all 64 activities analyzed for petroleum systems; therefore, some are estimated. Because of the dominance of the seven major sources, which account for 93.0 percent of the total emissions, the uncertainty surrounding these seven sources has been estimated most rigorously, and serves as the basis for determining the overall uncertainty of petroleum systems emission estimates.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-43 Petroleum systems CH_4 emissions in 2006 were estimated to be between 20.5 and 69.3 Tg CO_2 Eq., while CO_2 emissions were estimated to be between 0.2 and 0.7 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 28 percent below to 144 percent above the 2006 emission estimates of 28.4 and 0.3 Tg CO_2 Eq. for CH_4 and CO_2, respectively.

Table 3-43: Tier 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Petroleum Systems (Tg CO_2 Eq. and Percent)

Source	Gas	2006 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Petroleum Systems	CH_4	28.4	20.5	69.3	-28%	+144%
Petroleum Systems	CO_2	0.3	0.2	0.7	-28%	+144%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

Recalculations Discussion

Estimates of vented, fugitive, and process upset CO_2 emissions from the production sector were incorporated into the petroleum systems inventory for 1990-2006. CO_2 emissions were estimated using the methane emission sources' activity factors and drivers for the corresponding CO_2 emission sources. The emission factors for CO_2 were estimated by multiplying the methane emission factors by a conversion factor, which is the ratio of CO_2 content divided by methane content in produced associated gas. The only exceptions to this methodology are the emission factors for crude oil storage tanks, which were estimated from API TankCalc simulation runs. CO_2 emissions from the production sector account for 293 Gg of CO_2 in the year 2006. CO_2 emissions from the transportation and refining sectors are assumed to be negligible. Combustion emissions are already accounted for in the Fossils Fuels Combustion inventory.

In addition, two types of activity factor and seven types of activity driver revisions were made in the 2006 Petroleum Systems emissions inventory. All revisions but one were due to updating previous years' data with revised data from existing data sources. The one exception to the general revisions was the recalculation of an activity driver for oil platforms. Offshore oil and gas platform counts are driven by the percentage of total platforms that are located on oil and gas fields, respectively, as identified by MMS. This percentage can be calculated from MMS (2007a-c) for years 2003 onward. For year 1992, the estimate was provided by MMS by direct communication. The oil platform counts for years 1990, 1991, and 1993 through 2002 are driven by a linear projection based on known platform counts in 1992 and 2003. A miscalculation in year 2003 was re-estimated, causing the entire time series prior to year 2003 (except 1992) to change. This change resulted in a reallocation of platform counts to the natural gas and petroleum models. The total number of offshore platforms, both oil and gas, used as drivers remained the same.

Overall changes resulted in a decrease in total emissions of approximately 0.22 Tg CO_2 Eq. (0.8 percent) for year 2005. For 1990 and 1991, total emissions decreased by 2 percent or less; while between 1993 and 2004 the total emission estimates increased by up to 13 percent from the previous year's inventory estimates. This increase is largely due to the recalculation of the oil platform activity driver.

Planned Improvements

As noted above, nearly all emission factors used in the development of the petroleum systems estimates were taken from EPA (1995, 1996, 1999), with the remaining emission factors taken from EPA default values in (EPA 2005)

and a consensus of industry peer review panels. These emission factors will be reviewed as part of future inventory work. Results of this review and analysis will be incorporated into future inventories, as appropriate.

[BEGIN BOX]

Box 3-3. Carbon Dioxide Transport, Injection, and Geological Storage

Carbon dioxide is produced, captured, transported, and used for Enhanced Oil Recovery (EOR) as well as commercial and non-EOR industrial applications. This CO_2 is produced from both naturally-occurring CO_2 reservoirs and from industrial sources such as natural gas processing plants and ammonia plants. In the current Inventory, emissions from naturally-produced CO_2 are estimated based on the application.

In the current Inventory report, the CO_2 that is used in non-EOR industrial and commercial applications (e.g., food processing, chemical production) is assumed to be emitted to the atmosphere during its industrial use. These emissions are discussed in the Carbon Dioxide Consumption section. The naturally-occurring CO_2 used in EOR operations is assumed to be fully sequestered. Additionally, all anthropogenic CO_2 emitted from natural gas processing and ammonia plants is assumed to be emitted to the atmosphere, regardless of whether the CO_2 is captured or not. These emissions are currently included in the Natural Gas Systems and the Ammonia Manufacture sections of the Inventory report, respectively.

IPCC (2006) includes, for the first time, methodological guidance to estimate emissions from the capture, transport, injection, and geological storage of CO_2. The methodology is based on the principle that the carbon capture and storage system should be handled in a complete and consistent manner across the entire Energy sector. The approach accounts for CO_2 captured at natural and industrial sites as well as emissions from capture, transport, and use. For storage specifically, a Tier 3 methodology is outlined for estimating and reporting emissions based on site-specific evaluations. However, IPCC (2006) notes that if a national regulatory process exists, emissions information available through that process may support development of CO_2 emissions estimates for geologic storage.

In October 2007, the U.S. EPA announced plans to develop regulations for geologic sequestration of CO_2 under the EPA Underground Injection Control Program. Given that the regulatory process is in its early phases, and site-specific emissions estimates are not yet available, emissions estimates from CO_2 capture, transport, injection and geologic storage are not yet included in national totals. Preliminary estimates indicate that the amount of CO_2 captured from industrial and natural sites, as well as fugitive emissions from pipelines is 39.0 Tg CO_2 (39,041 Gg CO_2) (see Table 3-44). Site-specific monitoring and reporting data for CO_2 injection sites (i.e., EOR operations) were not readily available, therefore, these estimates assume all CO_2 is emitted.

Table 3-44: Potential Emissions from CO_2 Capture and Transport (Tg CO_2 Eq.)

Year	1990	1995	2000	2001	2002	2003	2004	2005	2006
Acid Gas Removal Plants	4.8	3.7	2.3	2.9	2.9	3.0	3.7	6.0	7.0
Naturally Occurring CO_2	15.1	22.7	23.1	23.4	23.0	24.4	27.0	28.2	31.4
Ammonia Production Plants	0.0	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Pipelines Transporting CO_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**20.0**	**26.9**	**26.1**	**27.0**	**26.6**	**28.1**	**31.4**	**34.9**	**39.0**

Table 3-45: Potential Emissions from CO_2 Capture and Transport (Gg)

Year	1990	1995	2000	2001	2002	2003	2004	2005	2006
Acid Gas Removal Plants	4,832	3,672	2,264	2,894	2,943	2,993	3,719	5,992	6,997
Naturally Occurring CO_2	15,129	22,547	23,149	23,442	22,967	24,395	27,002	28,192	31,359
Ammonia Production Plants	0	676	676	676	676	676	676	676	676
Pipelines Transporting CO_2	8	8	8	8	8	8	7	7	8

| Total | 19,969 | | 26,904 | | 26,098 | 27,020 | 26,595 | 28,073 | 31,405 | 34,868 | 39,041 |

[END BOX]

3.9.   Municipal Solid Waste Combustion (IPCC Source Category 1A5)

Combustion is used to manage about 7 to 17 percent of the municipal solid wastes (MSW) generated in the United States, depending on the source of the estimate and the scope of materials included in the definition of solid waste (EPA 2000b, Goldstein and Matdes 2001, Kaufman et al. 2004a, Simmons et al. 2006). Almost all combustion of municipal solid wastes in the United States occurs at waste-to-energy facilities where useful energy is recovered, and thus emissions from waste combustion are accounted for in the Energy chapter. Combustion of municipal solid wastes results in conversion of the organic inputs to CO_2. According to IPCC guidelines, when the CO_2 emitted is of fossil origin, it is counted as a net anthropogenic emission of CO_2 to the atmosphere. Thus, the emissions from waste combustion are calculated by estimating the quantity of waste combusted and the fraction of the waste that is C derived from fossil sources.

Most of the organic materials in municipal solid wastes are of biogenic origin (e.g., paper, yard trimmings), and have their net C flows accounted for under the Land Use, Land-Use Change, and Forestry chapter. However, some components—plastics, synthetic rubber, synthetic fibers, and carbon black—are of fossil origin. Plastics in the U.S. waste stream are primarily in the form of containers, packaging, and durable goods. Rubber is found in durable goods, such as carpets, and in non-durable goods, such as clothing and footwear. Fibers in municipal solid wastes are predominantly from clothing and home furnishings. Tires (which contain rubber and carbon black) are also considered a "non-hazardous" waste and are included in the municipal solid waste combustion estimate, though waste disposal practices for tires differ from the rest of municipal solid waste (viz., most combustion occurs outside of MSW combustion facilities).

Over 31 million metric tons of municipal solid wastes were combusted in the United States in 2006 (EPA 2007). CO_2 emissions from combustion of municipal solid wastes rose 91 percent since 1990, to an estimated 20.9 Tg CO_2 Eq. (20,922 Gg) in 2006, as the volume of synthetic fibers and other fossil C-containing materials in MSW increased (see Table 3-46 and Table 3-47). Waste combustion is also a source of N_2O emissions (De Soete 1993). N_2O emissions from municipal solid waste combustion were estimated to be 0.4 Tg CO_2 Eq. (1 Gg N_2O) in 2006, and have not changed significantly since 1990.

Table 3-46: CO_2 and N_2O Emissions from Municipal Solid Waste Combustion (Tg CO_2 Eq.)

Gas/Waste Product	1990		1995		2000	2001	2002	2003	2004	2005	2006
CO₂	10.9		15.7		17.5	18.0	18.5	19.1	20.1	20.7	20.9
Plastics	8.0		10.3		11.8	12.1	12.3	12.7	13.4	13.7	13.7
Synthetic Rubber in Tires	0.2		0.8		0.9	0.9	1.0	1.0	1.1	1.2	1.2
Carbon Black in Tires	0.2		1.1		1.2	1.2	1.2	1.3	1.4	1.6	1.6
Synthetic Rubber in MSW	1.3		1.6		1.6	1.7	1.8	1.8	1.9	1.9	1.9
Synthetic Fibers	1.2		1.8		2.0	2.1	2.2	2.3	2.3	2.4	2.5
N₂O	0.5		0.5		0.4	0.4	0.4	0.4	0.4	0.4	0.4
Total	11.4		16.2		17.9	18.4	18.9	19.5	20.5	21.1	21.3

Table 3-47: CO_2 and N_2O Emissions from Municipal Solid Waste Combustion (Gg)

Gas/Waste Product	1990		1995		2000	2001	2002	2003	2004	2005	2006
CO₂	10,950		15,712		17,518	17,971	18,458	19,058	20,097	20,673	20,922
Plastics	7,976		10,347		11,791	12,094	12,316	12,657	13,356	13,662	13,746
Synthetic Rubber in Tires	191		841		893	895	952	1,010	1,108	1,207	1,207
Carbon Black in Tires	249		1,099		1,167	1,170	1,245	1,320	1,449	1,579	1,579

Synthetic Rubber in MSW	1,334		1,596		1,640	1,721	1,760	1,815	1,871	1,873	1,902
Synthetic Fibers	1,200		1,830		2,027	2,090	2,185	2,257	2,312	2,352	2,489
N₂O	**2**		**1**		**1**	**1**	**1**	**1**	**1**	**1**	**1**

Methodology

Emissions of CO_2 from MSW combustion include CO_2 generated by the combustion of plastics, synthetic fibers, and synthetic rubber, as well as the combustion of synthetic rubber and carbon black in tires. These emissions were estimated by multiplying the amount of each material combusted by the C content of the material and the fraction oxidized (98 percent). Plastics combusted in municipal solid wastes were categorized into seven plastic resin types, each material having a discrete C content. Similarly, synthetic rubber is categorized into three product types, and synthetic fibers were categorized into four product types, each having a discrete C content. Scrap tires contain several types of synthetic rubber, as well as carbon black. Each type of synthetic rubber has a discrete C content, and carbon black is 100 percent C. Emissions of CO_2 were calculated based on the number of scrap tires used for fuel and the synthetic rubber and carbon black content of the tires.

More detail on the methodology for calculating emissions from each of these waste combustion sources is provided in Annex 3.6.

For each of the methods used to calculate CO_2 emissions from municipal solid waste combustion, data on the quantity of product combusted and the C content of the product are needed. For plastics, synthetic rubber, and synthetic fibers, the amount of material in municipal solid wastes and its portion combusted were taken from the *Characterization of Municipal Solid Waste in the United States* (EPA 2000b, 2002, 2003, 2005a, 2006b, 2007) and detailed unpublished backup data for some years not shown in the reports (Schneider 2007). For synthetic rubber and carbon black in scrap tires, information was obtained from *U.S. Scrap Tire Markets in the United States 2005 Edition* (RMA 2006) and *Scrap Tires, Facts and Figures* (STMC 2000 through 2003, 2006). For 2006, synthetic rubber data is set equal to 2005 due to a lack of more recently available data.

Average C contents for the "Other" plastics category, synthetic rubber in municipal solid wastes, and synthetic fibers were calculated from 1998 production statistics, which divide their respective markets by chemical compound. Information about scrap tire composition was taken from the Scrap Tire Management Council's internet site (STMC 2006).

The assumption that 98 percent of organic C is oxidized (which applies to all municipal solid waste combustion categories for CO_2 emissions) was reported in EPA's life cycle analysis of greenhouse gas emissions and sinks from management of solid waste (EPA 2006a).

Combustion of municipal solid waste also results in emissions of N_2O. These emissions were calculated as a function of the total estimated mass of municipal solid waste combusted and an emission factor. The N_2O emission estimates are based on different data sources than the CO_2 emission estimates. As noted above, N_2O emissions are a function of total waste combusted in each year; for 1990 through 2004, these data were derived from the information published in *BioCycle* (Simmons et al. 2006). Data on total waste combusted was not available for 2005 and 2006, so the values for 2005 and 2006 were assumed to equal the most recent value available (2004). Table 3-48 provides data on municipal solid waste generation and percentage combustion for the total waste stream. The emission factor of N_2O emissions per quantity of municipal solid waste combusted is an average of values from IPCC's *Good Practice Guidance* (2000).

Table 3-48: Municipal Solid Waste Generation (Metric Tons) and Percent Combusted

Year	Waste Generation	Combusted (%)
1990	266,365,714	11.5
1995	296,390,405	10.0
2000	371,071,109	7.0

2001	353,086,962[a]	7.4[a]
2002	335,102,816	7.7
2003	343,482,645[b]	7.6[b]
2004	351,862,474	7.4
2005	351,862,474[c]	7.4[c]
2006	351,86,2474[c]	7.4[c]

[a] Interpolated between 2000 and 2002 values.
[b] Interpolated between 2002 and 2004 values.
[c] Assumed equal to 2004 value.

Uncertainty

A Tier 2 Monte Carlo analysis was performed to determine the level of uncertainty surrounding the estimates of CO_2 emissions and N_2O emissions from municipal solid waste combustion. IPCC Tier 2 analysis allows the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. Uncertainty estimates and distributions for waste generation variables (i.e., plastics, synthetic rubber, and textiles generation) were obtained through a conversation with one of the authors of the *Municipal Solid Waste in the United States* reports. Statistical analyses or expert judgments of uncertainty were not available directly from the information sources for the other variables; thus, uncertainty estimates for these variables were determined using assumptions based on source category knowledge and the known uncertainty estimates for the waste generation variables.

The uncertainties in the waste combustion emission estimates arise from both the assumptions applied to the data and from the quality of the data. Key factors include MSW combustion rate; fraction oxidized; missing data on MSW composition; average C content of MSW components; assumptions on the synthetic/biogenic C ratio; and combustion conditions affecting N_2O emissions. The highest levels of uncertainty surround the variables that are based on assumptions (e.g., percent of clothing and footwear composed of synthetic rubber); the lowest levels of uncertainty surround variables that were determined by quantitative measurements (e.g., combustion efficiency, C content of C black).

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-49. Municipal solid waste combustion CO_2 emissions in 2006 were estimated to be between 16.8 and 23.7 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 20 percent below to 13 percent above the 2006 emission estimate of 20.9 Tg CO_2 Eq. Also at a 95 percent confidence level, municipal solid waste combustion N_2O emissions in 2006 were estimated to be between 0.1 and 1.1 Tg CO_2 Eq. This indicates a range of 66 percent below to 184 percent above the 2006 emission estimate of 0.4 Tg CO_2 Eq.

Table 3-49: Tier 2 Quantitative Uncertainty Estimates for CO_2 and N_2O from Municipal Solid Waste Combustion (Tg CO_2 Eq. and Percent)

Source	Gas	2006 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a]			
			(Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Municipal Solid Waste Combustion	CO_2	20.9	16.8	23.7	-20%	13%
Municipal Solid Waste Combustion	N_2O	0.4	0.1	1.1	-66%	184%

[a]Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

QA/QC and Verification

A source-specific QA/QC plan was implemented for MSW Combustion. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures that were implemented involved checks specifically

focusing on the activity data and specifically focused on the emission factor and activity data sources and methodology used for estimating emissions from MSW combustion. Trends across the time series were analyzed to determine whether any corrective actions were needed.

Planned Improvements

Additional data sources for calculating an N_2O emission factor for U.S. MSW combustion will be investigated for future drafts. In addition, the use of new techniques using radiocarbon dating to directly measure biogenic C content of MSW combustion flue gas will also be investigated. Additional data sources for calculating an N_2O emission factor for U.S. MSW combustion will be investigated for future drafts. In addition, the use of new techniques using radiocarbon dating to directly measure biogenic C content of MSW combustion flue gas will also be investigated. Furthermore, efforts have been initiated to reconcile differences in the separate data sources used for the CO_2 and N_2O emission calculations

3.10. Energy Sources of Indirect Greenhouse Gas Emissions

In addition to the main greenhouse gases addressed above, many energy-related activities generate emissions of indirect greenhouse gases. Total emissions of nitrogen oxides (NO_x), carbon monoxide (CO), and non-CH_4 volatile organic compounds (NMVOCs) from energy-related activities from 1990 to 2006 are reported in Table 3-50.

Table 3-50: NO_x, CO, and NMVOC Emissions from Energy-Related Activities (Gg)

Gas/Source	1990	1995	2000	2001	2002	2003	2004	2005	2006
NO_x	**21,024**	**20,631**	**18,537**	**17,714**	**17,364**	**16,474**	**15,607**	**15,005**	**14,309**
Mobile Combustion	10,920	10,622	10,310	9,819	10,154	9,642	9,191	8,739	8,287
Stationary Combustion	9,883	9,821	8,002	7,667	6,791	6,419	6,004	5,853	5,610
Oil and Gas Activities	139	100	111	113	321	316	316	316	315
Municipal Solid Waste Combustion	82	88	114	114	98	97	97	97	97
International Bunker Fuels*	*1,985*	*1,540*	*1,334*	*1,266*	*988*	*900*	*1,190*	*1,190*	*1,731*
CO	**125,640**	**104,402**	**89,715**	**86,046**	**82,148**	**77,689**	**73,731**	**69,773**	**65,815**
Mobile Combustion	119,360	97,630	83,559	79,851	75,421	71,038	67,096	63,154	59,213
Stationary Combustion	5,000	5,383	4,340	4,377	4,965	4,893	4,876	4,860	4,844
Municipal Solid Waste Combustion	302	316	146	147	323	321	321	321	322
Oil and Gas Activities	978	1,073	1,670	1,672	1,439	1,437	1,437	1,437	1,437
International Bunker Fuels*	*115*	*113*	*124*	*120*	*118*	*112*	*128*	*133*	*150*
NMVOCs	**12,620**	**10,538**	**8,953**	**8,610**	**9,608**	**9,223**	**8,910**	**8,597**	**8,284**
Mobile Combustion	10,932	8,745	7,230	6,872	7,235	6,885	6,587	6,289	5,991
Stationary Combustion	912	973	1,077	1,080	1,585	1,560	1,553	1,545	1,538
Oil and Gas Activities	554	582	389	400	545	538	533	528	523
Municipal Solid Waste Combustion	222	237	257	258	243	239	237	235	232
International Bunker Fuels*	*59*	*48*	*44*	*42*	*35*	*32*	*41*	*41*	*56*

* These values are presented for informational purposes only and are not included in totals.
Note: Totals may not sum due to independent rounding.

Methodology

These emission estimates were obtained from preliminary data (EPA 2008), and disaggregated based on EPA (2003), which, in its final iteration, will be published on the National Emission Inventory (NEI) Air Pollutant Emission Trends web site. Emissions were calculated either for individual categories or for many categories combined, using basic activity data (e.g., the amount of raw material processed) as an indicator of emissions. National activity data were collected for individual categories from various agencies. Depending on the category, these basic activity data may include data on production, fuel deliveries, raw material processed, etc.

Activity data were used in conjunction with emission factors, which together relate the quantity of emissions to the activity. Emission factors are generally available from the EPA's *Compilation of Air Pollutant Emission Factors, AP-42* (EPA 1997). The EPA currently derives the overall emission control efficiency of a source category from a variety of information sources, including published reports, the 1985 National Acid Precipitation and Assessment Program emissions inventory, and other EPA databases.

Uncertainty

Uncertainties in these estimates are partly due to the accuracy of the emission factors used and accurate estimates of activity data. A quantitative uncertainty analysis was not performed.

3.11. International Bunker Fuels (IPCC Source Category 1: Memo Items)

Emissions resulting from the combustion of fuels used for international transport activities, termed international bunker fuels under the UNFCCC, are currently not included in national emission totals, but are reported separately based upon location of fuel sales. The decision to report emissions from international bunker fuels separately, instead of allocating them to a particular country, was made by the Intergovernmental Negotiating Committee in establishing the Framework Convention on Climate Change.[42] These decisions are reflected in the *Revised 1996 IPCC Guidelines*, as well as the 2006 IPCC GLs, in which countries are requested to report emissions from ships or aircraft that depart from their ports with fuel purchased within national boundaries and are engaged in international transport separately from national totals (IPCC/UNEP/OECD/IEA 1997).[43]

Greenhouse gases emitted from the combustion of international bunker fuels, like other fossil fuels, include CO_2, CH_4 and N_2O. Two transport modes are addressed under the IPCC definition of international bunker fuels: aviation and marine.[44] Emissions from ground transport activities—by road vehicles and trains—even when crossing international borders are allocated to the country where the fuel was loaded into the vehicle and, therefore, are not counted as bunker fuel emissions.

The IPCC Guidelines distinguish between different modes of air traffic. Civil aviation comprises aircraft used for the commercial transport of passengers and freight, military aviation comprises aircraft under the control of national armed forces, and general aviation applies to recreational and small corporate aircraft. The IPCC Guidelines further define international bunker fuel use from civil aviation as the fuel combusted for civil (e.g., commercial) aviation purposes by aircraft arriving or departing on international flight segments. However, as mentioned above, and in keeping with the IPCC Guidelines, only the fuel purchased in the United States and used by aircraft taking-off (i.e., departing) from the United States are reported here. The standard fuel used for civil aviation is kerosene-type jet fuel, while the typical fuel used for general aviation is aviation gasoline.[45]

Emissions of CO_2 from aircraft are essentially a function of fuel use. CH_4 and N_2O emissions also depend upon engine characteristics, flight conditions, and flight phase (i.e., take-off, climb, cruise, decent, and landing). CH_4 is the product of incomplete combustion and occur mainly during the landing and take-off phases. In jet engines, N_2O is primarily produced by the oxidation of atmospheric nitrogen, and the majority of emissions occur during the cruise phase. International marine bunkers comprise emissions from fuels burned by ocean-going ships of all flags

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[42] See report of the Intergovernmental Negotiating Committee for a Framework Convention on Climate Change on the work of its ninth session, held at Geneva from 7 to 18 February 1994 (A/AC.237/55, annex I, para. 1c).

[43] Note that the definition of international bunker fuels used by the UNFCCC differs from that used by the International Civil Aviation Organization.

[44] Most emission related international aviation and marine regulations are under the rubric of the International Civil Aviation Organization (ICAO) or the International Maritime Organization (IMO), which develop international codes, recommendations, and conventions, such as the International Convention of the Prevention of Pollution from Ships (MARPOL).

[45] Naphtha-type jet fuel was used in the past by the military in turbojet and turboprop aircraft engines.

that are engaged in international transport. Ocean-going ships are generally classified as cargo and passenger carrying, military (i.e., Navy), fishing, and miscellaneous support ships (e.g., tugboats). For the purpose of estimating greenhouse gas emissions, international bunker fuels are solely related to cargo and passenger carrying vessels, which is the largest of the four categories, and military vessels. Two main types of fuels are used on sea-going vessels: distillate diesel fuel and residual fuel oil. CO_2 is the primary greenhouse gas emitted from marine shipping.

Overall, aggregate greenhouse gas emissions in 2006 from the combustion of international bunker fuels from both aviation and marine activities were 128.4 Tg CO_2 Eq., or 12 percent above emissions in 1990 (see Table 3-51 and Table 3-52). Although emissions from international flights departing from the United States have increased significantly (56 percent), emissions from international shipping voyages departing the United States have decreased by 18 percent since 1990. The majority of these emissions were in the form of CO_2; however, small amounts of CH_4 and N_2O were also emitted.

Table 3-51: CO_2, CH_4, and N_2O Emissions from International Bunker Fuels (Tg CO_2 Eq.)

Gas/Mode	1990	1995	2000	2001	2002	2003	2004	2005	2006
CO_2	113.7	100.6	101.1	97.6	89.1	103.6	119.0	122.6	127.1
Aviation	45.7	50.2	59.9	58.7	61.1	58.8	64.9	67.5	71.1
Marine	68.0	50.4	41.3	38.9	28.0	44.8	54.1	55.1	56.0
CH_4	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2
Aviation	+	+	+	+	+	+	+	+	+
Marine	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
N_2O	1.0	0.9	0.9	0.9	0.8	0.8	1.1	1.1	1.1
Aviation	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.7	0.7
Marine	0.5	0.4	0.3	0.3	0.2	0.3	0.4	0.4	0.4
Total	114.8	101.6	102.2	98.6	90.0	104.6	120.2	123.8	128.4

+ Does not exceed 0.05 Tg CO_2 Eq.
Note: Totals may not sum due to independent rounding. Includes aircraft cruise altitude emissions.

Table 3-52: CO_2, CH_4 and N_2O Emissions from International Bunker Fuels (Gg)

Gas/Mode	1990	1995	2000	2001	2002	2003	2004	2005	2006
CO_2	113,683	100,627	101,125	97,563	89,101	103,583	118,975	122,580	127,097
Aviation	45,731	50,202	59,853	58,696	61,120	58,806	64,891	67,517	71,141
Marine	67,952	50,425	41,272	38,866	27,981	44,777	54,084	55,063	55,956
CH_4	8	6	6	5	4	6	7	7	7
Aviation	1	1	2	2	2	2	2	2	2
Marine	7	5	4	4	3	4	5	5	5
N_2O	3	3	3	3	3	3	3	4	4
Aviation	1	2	2	2	2	2	2	2	2
Marine	2	1	1	1	1	1	1	1	1

Note: Totals may not sum due to independent rounding. Includes aircraft cruise altitude emissions.

Methodology

Emissions of CO_2 were estimated by applying C content and fraction oxidized factors to fuel consumption activity data. This approach is analogous to that described under CO_2 from Fossil Fuel Combustion. C content and fraction oxidized factors for jet fuel, distillate fuel oil, and residual fuel oil were taken directly from EIA and are presented in Annex 2.1, Annex 2.2, and Annex 3.7 of this Inventory. Density conversions were taken from Chevron (2000), ASTM (1989), and USAF (1998). Heat content for distillate fuel oil and residual fuel oil were taken from EIA (2007) and USAF (1998), and heat content for jet fuel was taken from EIA (2007). A complete description of the methodology and a listing of the various factors employed can be found in Annex 2.1. See Annex 3.7 for a specific discussion on the methodology used for estimating emissions from international bunker fuel use by the U.S. military.

Emission estimates for CH_4 and N_2O were calculated by multiplying emission factors by measures of fuel consumption by fuel type and mode. Emission factors used in the calculations of CH_4 and N_2O emissions were obtained from the *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997). For aircraft emissions, the following values, in units of grams of pollutant per kilogram of fuel consumed (g/kg), were employed: 0.09 for CH_4 and 0.1 for N_2O For marine vessels consuming either distillate diesel or residual fuel oil the following values (g/MJ), were employed: 0.32 for CH_4 and 0.08 for N_2O. Activity data for aviation included solely jet fuel consumption statistics, while the marine mode included both distillate diesel and residual fuel oil.

Activity data on aircraft fuel consumption were collected from three government agencies. Jet fuel consumed by U.S. flag air carriers for international flight segments was supplied by the Bureau of Transportation Statistics (DOT 1991 through 2006). It was assumed that 50 percent of the fuel used by U.S. flagged carriers for international flights—both departing and arriving in the United States—was purchased domestically for flights departing from the United States. In other words, only one-half of the total annual fuel consumption estimate was used in the calculations. Data on jet fuel expenditures by foreign flagged carriers departing U.S. airports was taken from unpublished data collected by the Bureau of Economic Analysis (BEA) under the U.S. Department of Commerce (BEA 1991 through 2006). Approximate average fuel prices paid by air carriers for aircraft on international flights was taken from DOT (1991 through 2006) and used to convert the BEA expenditure data to gallons of fuel consumed. Data on U.S. Department of Defense (DoD) aviation bunker fuels and total jet fuel consumed by the U.S. military was supplied by the Office of the Under Secretary of Defense (Installations and Environment), DoD. Estimates of the percentage of each Service's total operations that were international operations were developed by DoD. Military aviation bunkers included international operations, operations conducted from naval vessels at sea, and operations conducted from U.S. installations principally over international water in direct support of military operations at sea. Military aviation bunker fuel emissions were estimated using military fuel and operations data synthesized from unpublished data by the Defense Energy Support Center, under DoD's Defense Logistics Agency (DESC 2007). Together, the data allow the quantity of fuel used in military international operations to be estimated. Densities for each jet fuel type were obtained from a report from the U.S. Air Force (USAF 1998). Final jet fuel consumption estimates are presented in Table 3-53. See Annex 3.7 for additional discussion of military data.

Activity data on distillate diesel and residual fuel oil consumption by cargo or passenger carrying marine vessels departing from U.S. ports were taken from unpublished data collected by the Foreign Trade Division of the U.S. Department of Commerce's Bureau of the Census (DOC 1991 through 2007) for 1990 through 2002, and the Department of Homeland Security's Bunker Report for 2003 through 2006 (DHS 2008). Activity data on distillate diesel consumption by military vessels departing from U.S. ports were provided by DESC (2007). The total amount of fuel provided to naval vessels was reduced by 13 percent to account for fuel used while the vessels were not-underway (i.e., in port). Data on the percentage of steaming hours underway versus not-underway were provided by the U.S. Navy. These fuel consumption estimates are presented in Table 3-53.

Table 3-53: Aviation Jet Fuel Consumption for International Transport (Million Gallons)

Nationality	1990	1995	2000	2001	2002	2003	2004	2005	2006
U.S. and Foreign Carriers	1,954	2,221	2,737	2,619	2,495	2,418	2,466	2,760	2,914
Foreign Carriers	2,051	2,544	3,162	3,113	3,537	3,377	3,953	3,975	4,272
U.S. Military	862	581	480	524	482	473	498	462	400
Total	**4,867**	**5,347**	**6,380**	**6,255**	**6,515**	**6,268**	**6,917**	**7,198**	**7,586**

Note: Totals may not sum due to independent rounding.

Table 3-54: Marine Fuel Consumption for International Transport (Million Gallons)

Fuel Type	1990	1995	2000	2001	2002	2003	2004	2005	2006
Residual Fuel Oil	4,781	3,495	2,967	2,846	1,937	3,152	3,695	3,881	4,004
Distillate Diesel Fuel & Other	617	573	290	204	158	290	505	444	446
U.S. Military Naval Fuels	522	334	329	318	348	459	530	471	414
Total	**5,920**	**4,402**	**3,586**	**3,368**	**2,443**	**3,901**	**4,730**	**4,796**	**4,864**

Note: Totals may not sum due to independent rounding.

Uncertainty

Emission estimates related to the consumption of international bunker fuels are subject to the same uncertainties as those from domestic aviation and marine mobile combustion emissions; however, additional uncertainties result from the difficulty in collecting accurate fuel consumption activity data for international transport activities separate from domestic transport activities.[46] For example, smaller aircraft on shorter routes often carry sufficient fuel to complete several flight segments without refueling in order to minimize time spent at the airport gate or take advantage of lower fuel prices at particular airports. This practice, called tankering, when done on international flights, complicates the use of fuel sales data for estimating bunker fuel emissions. Tankering is less common with the type of large, long-range aircraft that make many international flights from the United States, however. Similar practices occur in the marine shipping industry where fuel costs represent a significant portion of overall operating costs and fuel prices vary from port to port, leading to some tankering from ports with low fuel costs.

Particularly for aviation, the DOT (1991 through 2007) international flight segment fuel data used for U.S. flagged carriers does not include smaller air carriers and unfortunately defines flights departing to Canada and some flights to Mexico as domestic instead of international. As for the BEA (1991 through 2007) data on foreign flagged carriers, there is some uncertainty as to the average fuel price, and to the completeness of the data. It was also not possible to determine what portion of fuel purchased by foreign carriers at U.S. airports was actually used on domestic flight segments; this error, however, is believed to be small.[47]

Uncertainties exist with regard to the total fuel used by military aircraft and ships, and in the activity data on military operations and training that were used to estimate percentages of total fuel use reported as bunker fuel emissions. Total aircraft and ship fuel use estimates were developed from DoD records, which document fuel sold to the Navy and Air Force from the Defense Logistics Agency. These data may slightly over or under estimate actual total fuel use in aircraft and ships because each Service may have procured fuel from, and/or may have sold to, traded with, and/or given fuel to other ships, aircraft, governments, or other entities. There are uncertainties in aircraft operations and training activity data. Estimates for the quantity of fuel actually used in Navy and Air Force flying activities reported as bunker fuel emissions had to be estimated based on a combination of available data and expert judgment. Estimates of marine bunker fuel emissions were based on Navy vessel steaming hour data, which reports fuel used while underway and fuel used while not underway. This approach does not capture some voyages that would be classified as domestic for a commercial vessel. Conversely, emissions from fuel used while not underway preceding an international voyage are reported as domestic rather than international as would be done for a commercial vessel. There is uncertainty associated with ground fuel estimates for 1997 through 2001. Small fuel quantities may have been used in vehicles or equipment other than that which was assumed for each fuel type.

There are also uncertainties in fuel end-uses by fuel-type, emissions factors, fuel densities, diesel fuel sulfur content, aircraft and vessel engine characteristics and fuel efficiencies, and the methodology used to back-calculate the data set to 1990 using the original set from 1995. The data were adjusted for trends in fuel use based on a closely correlating, but not matching, data set. All assumptions used to develop the estimate were based on process knowledge, Department and military Service data, and expert judgments. The magnitude of the potential errors related to the various uncertainties has not been calculated, but is believed to be small. The uncertainties associated with future military bunker fuel emission estimates could be reduced through additional data collection.

Although aggregate fuel consumption data have been used to estimate emissions from aviation, the recommended method for estimating emissions of gases other than CO_2 in the *Revised 1996 IPCC Guidelines* is to use data by specific aircraft type (IPCC/UNEP/OECD/IEA 1997). The IPCC also recommends that cruise altitude emissions be estimated separately using fuel consumption data, while landing and take-off (LTO) cycle data be used to estimate

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[46] See uncertainty discussions under Carbon Dioxide Emissions from Fossil Fuel Combustion.

[47] Although foreign flagged air carriers are prevented from providing domestic flight services in the United States, passengers may be collected from multiple airports before an aircraft actually departs on its international flight segment. Emissions from these earlier domestic flight segments should be classified as domestic, not international, according to the IPCC.

near-ground level emissions of gases other than CO_2.[48]

There is also concern as to the reliability of the existing DOC (1991 through 2007) data on marine vessel fuel consumption reported at U.S. customs stations due to the significant degree of inter-annual variation.

QA/QC and Verification

A source-specific QA/QC plan for international bunker fuels was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and emission factor sources and methodology used for estimating CO_2, CH_4, and N_2O from international bunker fuels in the United States. Emission totals for the different sectors and fuels were compared and trends were investigated. No corrective actions were necessary.

Recalculations Discussion

Historical activity data for aviation was revised for both U.S. and foreign carriers. In addition, distillate and residual fuel oil consumption by cargo or passenger carrying marine vessels from 2003 through 2006 was revised using DHS (2008). These historical data changes resulted in changes to the emission estimates for 1990 through 2005, which averaged to an annual decrease in emissions from international bunker fuels of 4.3 Tg CO_2 Eq. (4.7 percent) in CO_2 emissions, an annual decrease of less than 0.1 Tg CO_2 Eq. (8 percent) in CH_4 emissions, and annual decrease of less than 0.1 Tg CO_2 Eq. (4 percent) in N_2O emissions.

3.12. Wood Biomass and Ethanol Consumption (IPCC Source Category 1A)

The combustion of biomass fuels—such as wood, charcoal, and wood waste—and biomass-based fuels—such as ethanol from corn and woody crops—generates CO_2. However, in the long run the CO_2 emitted from biomass consumption does not increase atmospheric CO_2 concentrations, assuming that the biogenic C emitted is offset by the uptake of CO_2 that results from the growth of new biomass. As a result, CO_2 emissions from biomass combustion have been estimated separately from fossil fuel-based emissions and are not included in the U.S. totals. Net C fluxes from changes in biogenic C reservoirs in wooded or crop lands are accounted for in the Land Use, Land-Use Change, and Forestry chapter.

In 2006, total CO_2 emissions from the burning of woody biomass in the industrial, residential, commercial, and electricity generation sectors were approximately 204.4 Tg CO_2 Eq. (204,435 Gg) (see Table 3-55 and Table 3-56). As the largest consumer of woody biomass, the industrial sector was responsible for 67 percent of the CO_2 emissions from this source. The residential sector was the second largest emitter, constituting 20 percent of the total, while the commercial and electricity generation sectors accounted for the remainder.

Table 3-55: CO_2 Emissions from Wood Consumption by End-Use Sector (Tg CO_2 Eq.)

End-Use Sector	1990		1995		2000	2001	2002	2003	2004	2005	2006
Industrial	135.3		155.1		153.6	135.4	131.1	128.0	138.5	136.3	137.9
Residential	59.8		53.6		43.3	38.2	39.2	41.2	42.3	42.3	40.2
Commercial	6.8		7.5		7.4	6.9	7.1	7.4	7.3	7.2	6.7

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[48] U.S. aviation emission estimates for CO, NO_x, and NMVOCs are reported by EPA's National Emission Inventory (NEI) Air Pollutant Emission Trends web site, and reported under the Mobile Combustion section. It should be noted that these estimates are based solely upon LTO cycles and consequently only capture near ground-level emissions, which are more relevant for air quality evaluations. These estimates also include both domestic and international flights. Therefore, estimates reported under the Mobile Combustion section overestimate IPCC-defined domestic CO, NO_x, and NMVOC emissions by including landing and take-off (LTO) cycles by aircraft on international flights, but underestimate because they do not include emissions from aircraft on domestic flight segments at cruising altitudes. The estimates in Mobile Combustion are also likely to include emissions from ocean-going vessels departing from U.S. ports on international voyages.

Electricity Generation	13.3		12.9		13.9	13.0	15.5	17.3	17.0	19.1	19.6
Total	**215.2**		**229.1**		**218.1**	**193.5**	**192.8**	**193.8**	**205.1**	**204.8**	**204.4**

Note: Totals may not sum due to independent rounding.

Table 3-56: CO_2 Emissions from Wood Consumption by End-Use Sector (Gg)

End-Use Sector	1990		1995		2000	2001	2002	2003	2004	2005	2006
Industrial	135,348		155,075		153,559	135,415	131,079	127,970	138,522	136,269	137,929
Residential	59,808		53,621		43,309	38,153	39,184	41,247	42,278	42,278	40,215
Commercial	6,779		7,463		7,370	6,887	7,080	7,366	7,252	7,191	6,685
Electricity Generation	13,252		12,932		13,851	13,034	15,487	17,250	17,034	19,704	19,606
Total	**215,186**		**229,091**		**218,088**	**193,489**	**192,830**	**193,833**	**205,086**	**204,812**	**204,435**

Note: Totals may not sum due to independent rounding.

Biomass-derived fuel consumption in the United States consisted primarily of ethanol use in the transportation sector. Ethanol is primarily produced from corn grown in the Midwest, and was used mostly in the Midwest and South. Pure ethanol can be combusted, or it can be mixed with gasoline as a supplement or octane-enhancing agent. The most common mixture is a 90 percent gasoline, 10 percent ethanol blend known as gasohol. Ethanol and ethanol blends are often used to fuel public transport vehicles such as buses, or centrally fueled fleet vehicles. These fuels burn cleaner than gasoline (i.e., lower in NO_x and hydrocarbon emissions), and have been employed in urban areas with poor air quality. However, because ethanol is a hydrocarbon fuel, its combustion emits CO_2.

In 2006, the United States consumed an estimated 459 trillion Btu of ethanol, and as a result, produced approximately 30.3 Tg CO_2 Eq. (30,291 Gg) (see Table 3-57 and) of CO_2 emissions. Ethanol production and consumption has grown steadily every year since 1990, with the exception of 1996 due to short corn supplies and high prices in that year.

Table 3-57: CO_2 Emissions from Ethanol Consumption (Tg CO_2 Eq.)

End-Use Sector	1990		1995		2000	2001	2002	2003	2004	2005	2006
Transportation	4.1		7.6		9.1	9.5	11.3	15.4	19.3	22.0	29.6
Industrial	0.1		0.1		0.1	0.2	0.2	0.3	0.4	0.5	0.6
Commercial	+		+		+	+	+	0.1	0.1	0.1	0.1
Total	**4.2**		**7.7**		**9.2**	**9.7**	**11.5**	**15.7**	**19.7**	**22.6**	**30.3**

+ Does not exceed 0.05 Tg CO_2 Eq.

Table 3-58: CO_2 Emissions from Ethanol Consumption (Gg)

End-Use Sector	1990		1995		2000	2001	2002	2003	2004	2005	2006
Transportation	4,066		7,570		9,078	9,479	11,280	15,353	19,267	22,014	29,566
Industrial	55		104		85	172	209	296	418	478	641
Commercial	33		9		25	22	31	55	55	62	84
Total	**4,155**		**7,683**		**9,188**	**9,673**	**11,520**	**15,704**	**19,740**	**22,554**	**30,291**

Methodology

Woody biomass emissions were estimated by applying two EIA gross heat contents (Lindstrom 2006) to U.S. consumption data (EIA 2007) (see Table 3-59), provided in energy units for the industrial, residential, commercial, and electric generation sectors. One heat content (16.953114 MMBtu/MT wood and wood waste) was applied to the industrial sector's consumption, while the other heat content (15.432359 MMBtu/MT wood and wood waste) was applied to the consumption data for the other sectors. An EIA emission factor of 0.434 MT C/MT wood (Lindstrom 2006) was then applied to the resulting quantities of woody biomass to obtain CO_2 emission estimates. It was assumed that the woody biomass contains black liquor and other wood wastes, has a moisture content of 12 percent, and is converted into CO_2 with 100 percent efficiency. The emissions from ethanol consumption were calculated by applying an EIA emission factor of 17.99 Tg C/QBtu (Lindstrom 2006) to U.S. ethanol consumption

estimates that were provided in energy units (EIA 2007) (see Table 3-60).

Table 3-59: Woody Biomass Consumption by Sector (Trillion Btu)

End-Use Sector	1990		1995		2000	2001	2002	2003	2004	2005	2006
Industrial	1,442		1,652		1,636	1,443	1,396	1,363	1,476	1,452	1,469
Residential	580		520		420	370	380	400	410	410	390
Commercial	66		72		71	67	69	71	70	70	65
Electricity Generation	129		125		134	126	150	167	165	185	190
Total	**2,216**		**2,370**		**2,262**	**2,006**	**1,995**	**2,002**	**2,121**	**2,116**	**2,114**

Table 3-60: Ethanol Consumption (Trillion Btu)

End-Use Sector	1990		1995		2000	2001	2002	2003	2004	2005	2006
Transportation	61.7		114.8		137.7	143.7	171.0	232.8	292.1	333.8	448.3
Industrial	0.8		1.6		1.3	2.6	3.2	4.5	6.3	7.2	9.7
Commercial	0.5		0.1		0.4	0.3	0.5	0.8	0.8	0.9	1.3
Total	**63.0**		**116.5**		**139.3**	**146.7**	**174.7**	**238.1**	**299.3**	**342.0**	**459.3**

Uncertainty

It is assumed that the combustion efficiency for woody biomass is 100 percent, which is believed to be an overestimate of the efficiency of wood combustion processes in the United States. Decreasing the combustion efficiency would increase emission estimates. Additionally, the heat content applied to the consumption of woody biomass in the residential, commercial, and electric power sectors is unlikely to be a completely accurate representation of the heat content for all the different types of woody biomass consumed within these sectors. Emission estimates from ethanol production are more certain than estimates from woody biomass consumption due to better activity data collection methods and uniform combustion techniques.

Recalculations Discussion

Residential wood consumption values were revised in 1997, 1999, and 2000 based on updated information from EIA's Annual Energy Review (EIA 2007). EIA (2007) also reported minor changes in wood consumption for all sectors in 2005. This adjustment of historical data for wood biomass consumption resulted in an average annual increase in emissions from wood biomass consumption of 1.1 Tg CO_2 Eq. (0.6 percent) from 1990 through 2005. Industrial and commercial sector ethanol consumption is now estimated in EIA (2007), which slightly decreased estimates for ethanol consumed in the transportation sector in all years. As a result of these adjustments, average annual emissions from ethanol consumption in the transportation sector decreased by 0.2 Tg CO_2 Eq. (1.8 percent).
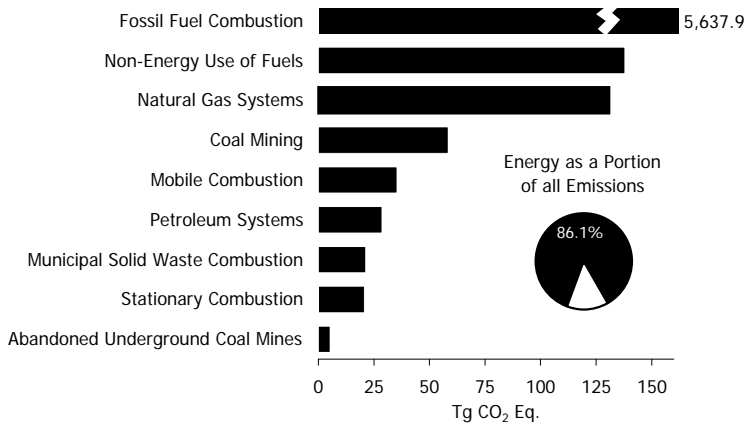
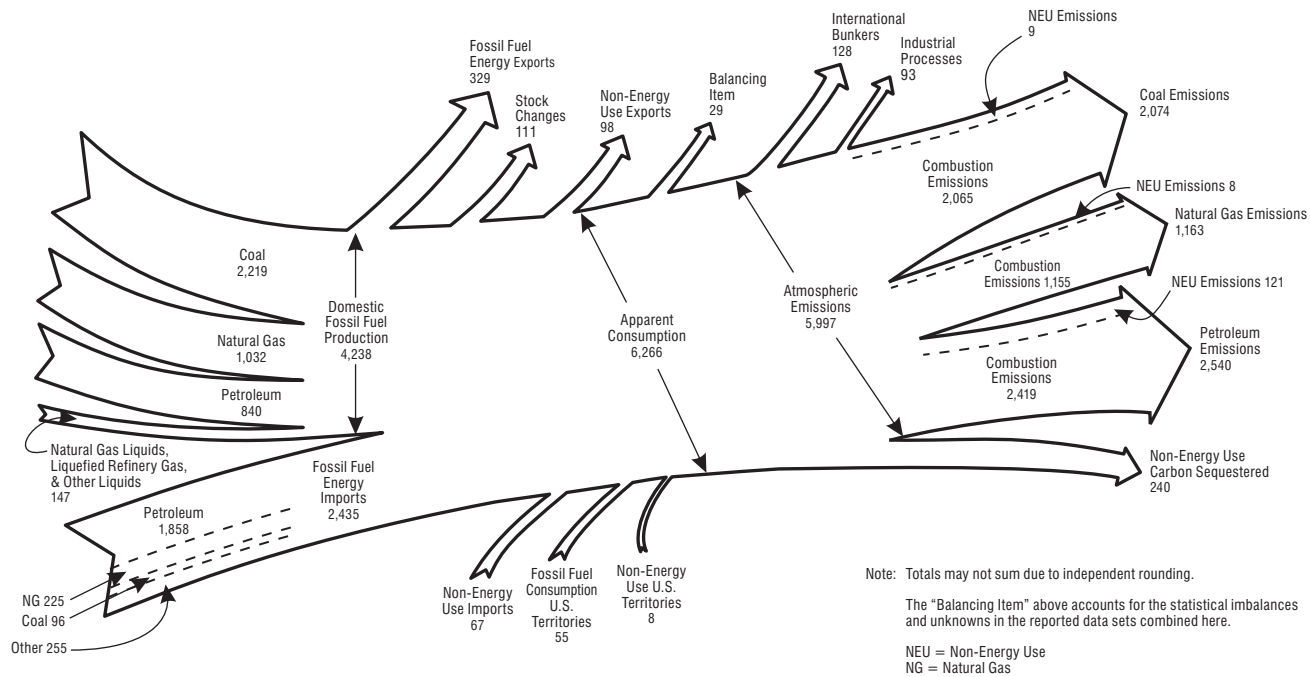Figure 3-1: 2006 Energy Sector Greenhouse Gas Sources
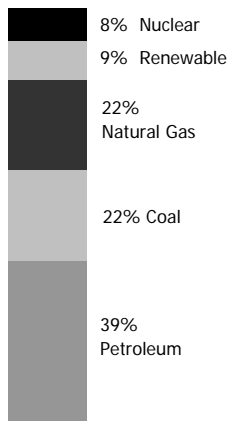
Figure 3-2 2006 U.S. Fossil Carbon Flows (Tg CO$_2$ Eq.)

Fossil Fuel Energy Exports 329

Stock Changes 111

Non-Energy Use Exports 98

Balancing Item 29

International Bunkers 128

Industrial Processes 93

NEU Emissions 9

Coal Emissions 2,074

Combustion Emissions 2,065

NEU Emissions 8

Natural Gas Emissions 1,163

Combustion Emissions 1,155

NEU Emissions 121

Petroleum Emissions 2,540

Combustion Emissions 2,419

Coal 2,219

Natural Gas 1,032

Petroleum 840

Domestic Fossil Fuel Production 4,238

Apparent Consumption 6,266

Atmospheric Emissions 5,997

Natural Gas Liquids, Liquefied Refinery Gas, & Other Liquids 147

Fossil Fuel Energy Imports 2,435

Non-Energy Use Carbon Sequestered 240

Petroleum 1,858

NG 225

Coal 96

Other 255

Non-Energy Use Imports 67

Fossil Fuel Consumption U.S. Territories 55

Non-Energy Use U.S. Territories 8

Note: Totals may not sum due to independent rounding.

The "Balancing Item" above accounts for the statistical imbalances and unknowns in the reported data sets combined here.

NEU = Non-Energy Use
NG = Natural Gas

8% Nuclear

9% Renewable

22%
Natural Gas

22% Coal

39%
Petroleum

Figure 3-3: 2006 U.S. Energy Consumption by Energy Source

Figure 3-4: U.S. Energy Consumption (Quadrillion Btu)
Note: Expressed as gross calorific values
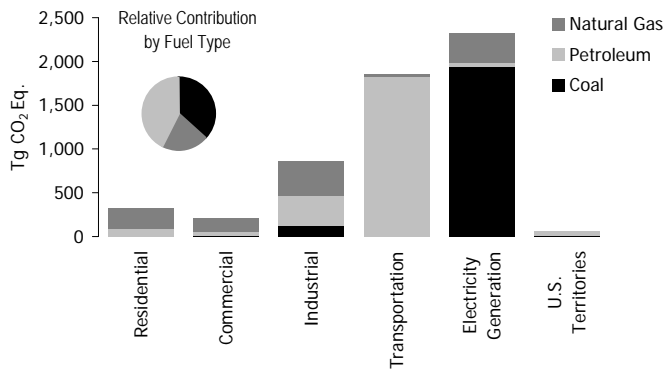
Figure 3-5: 2006 CO$_2$ Emissions from Fossil Fuel Combustion by Sector and Fuel Type
Note: The electricity generation sector also includes emissions of less than 0.5 Tg CO$_2$ Eq.
    from geothermal-based electricity generation
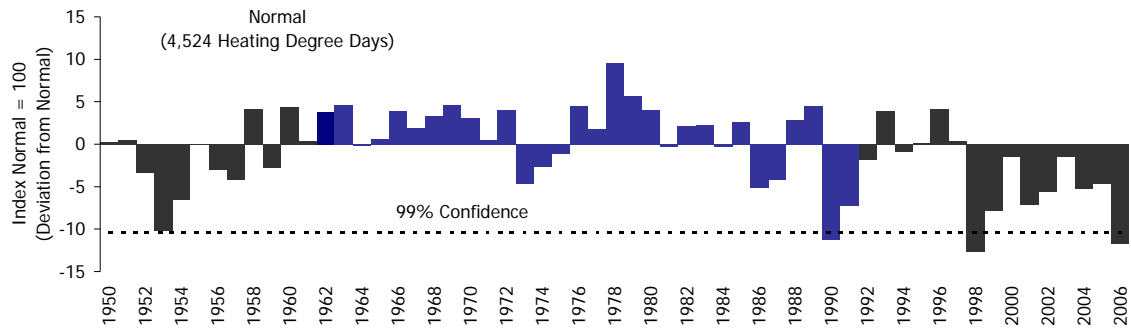
Figure 3-6. Annual Deviations from Normal Heating Degree Days for the United States (1950-2006)
Note: Climatological normal data are highlighted.
Statistical confidence interval for "normal" climatology period of 1961 through 1990.
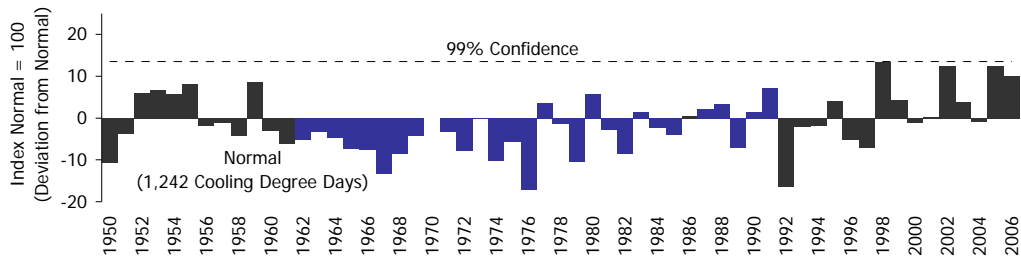
Figure 3-7: Annual Deviations from Normal Cooling Degree Days for the United States (1950-2006)
Note: Climatological normal data are highlighted.
Statistical confidence interval for "normal" climatology period of 1961 through 1990.
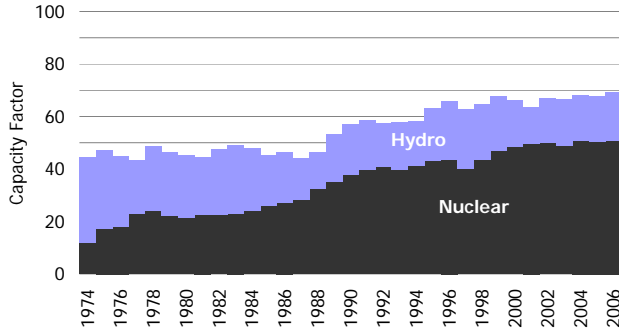
Figure 3-8: Aggregate Nuclear and Hydroelectric Power Plant Capacity Factors in the United States (1974-2006)
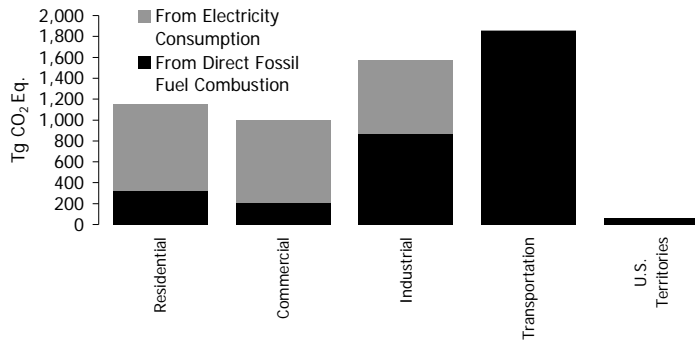
Figure 3-9: 2006 End-Use Sector Emissions of CO$_2$ from Fossil Fuel Combustion
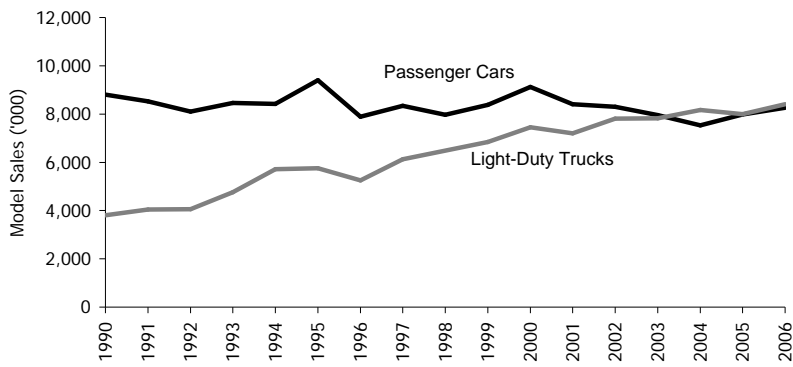
Figure 3-10: Sales of New Automobiles and Light-Duty Trucks, 1990-2006
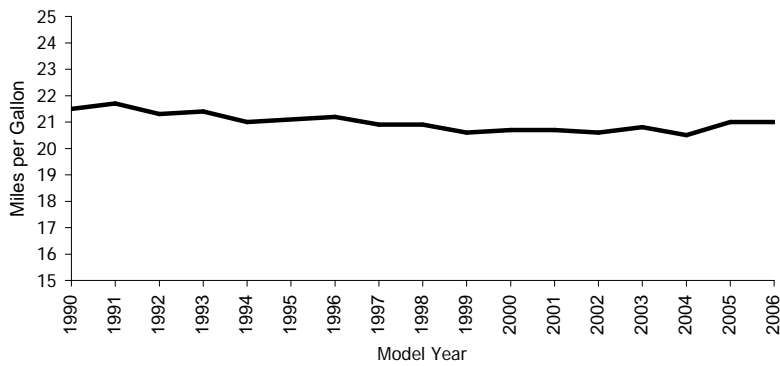
Figure 3-11: Sales-Weighted Fuel Economy of New Automobiles and Light-Duty Trucks, 1990-2006
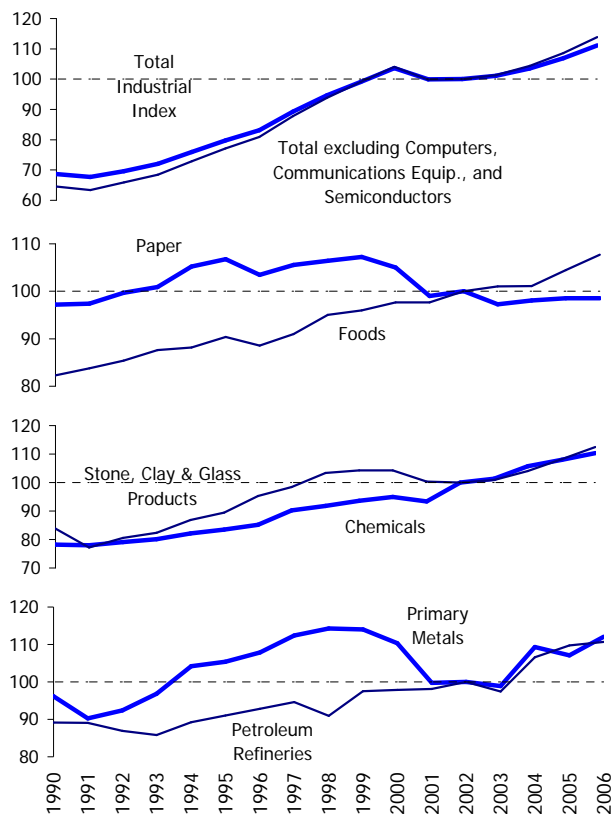
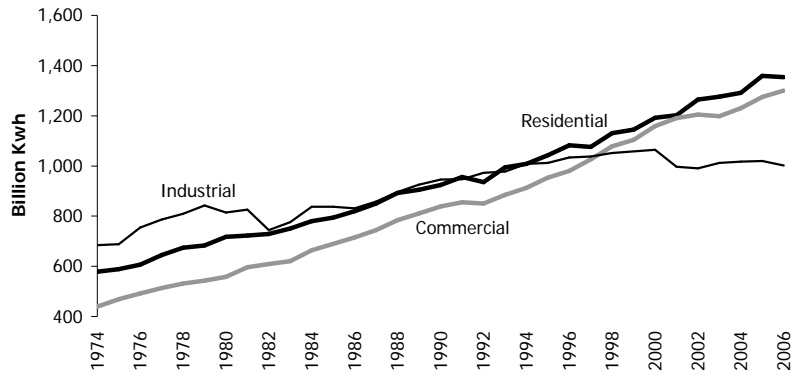Figure 3-12: Industrial Production Indexes (Index 2002=100)

Figure 3-13: Electric Generation Retail Sales by End-Use Sector
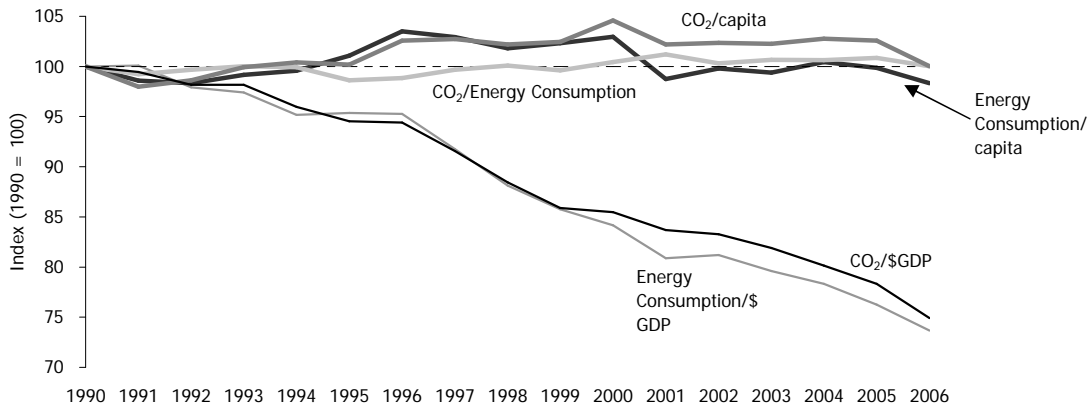Note: The transportation end-use sector consumes minor quanties of electricity.

Figure 3-14: U.S. Energy Consumption and Energy-Related CO_2 Emissions Per Capita and Per Dollar GDP
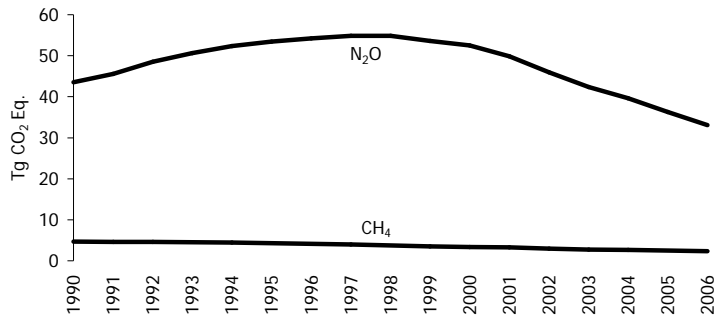

Figure 3-15: Mobile Source CH_4 and N_2O Emissions