3. Energy

Energy-related activities were the primary sources of U.S. anthropogenic greenhouse gas emissions, accounting for 87.0 percent of total greenhouse gas emissions on a carbon dioxide (CO_2) equivalent basis[53] in 2010. This included 97, 50, and 14 percent of the nation's CO_2, methane (CH_4), and nitrous oxide (N_2O) emissions, respectively. Energy-related CO_2 emissions alone constituted 81 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 (5.5 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 30,313 Tg of CO_2 were added to the atmosphere through the combustion of fossil fuels in 2009, of which the United States accounted for about 18 percent.[54] Due to their relative importance, fossil fuel combustion-related CO_2 emissions 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. Stationary combustion of fossil fuels was the second largest source of N_2O emissions in the United States and mobile fossil fuel combustion was the third largest source.

Figure 3-1: 2010 Energy Chapter Greenhouse Gas Sources

Figure 3-2: 2010 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.

Table 3-1 summarizes emissions from the Energy sector in units of teragrams (or million metric tons) 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 5,933.5 Tg CO_2 Eq. in 2010, an increase of 12 percent since 1990.

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

Gas/Source	1990	2005	2006	2007	2008	2009	2010
CO_2	**4,903.9**	**5,933.3**	**5,840.4**	**5,936.7**	**5,755.2**	**5,374.1**	**5,557.6**
Fossil Fuel Combustion	4,738.3	5,746.5	5,653.0	5,757.8	5,571.5	5,206.2	5,387.8
Electricity Generation	1,820.8	2,402.1	2,346.4	2,412.8	2,360.9	2,146.4	2,258.4
Transportation	1,485.9	1,896.6	1,878.1	1,893.9	1,789.8	1,727.9	1,745.5
Industrial	846.4	816.4	848.1	844.4	806.5	726.6	777.8
Residential	338.3	357.9	321.5	341.6	349.3	339.0	340.2
Commercial	219.0	223.5	208.6	218.9	225.1	224.6	224.2
U.S. Territories	27.9	50.0	50.3	46.1	39.8	41.7	41.6
Non-Energy Use of Fuels	119.6	144.1	143.8	134.9	138.6	123.7	125.1
Natural Gas Systems	37.6	29.9	30.8	31.0	32.8	32.2	32.3
Incineration of Waste	8.0	12.5	12.5	12.7	11.9	11.7	12.1
Petroleum Systems	0.4	0.3	0.3	0.3	0.3	0.3	0.3
*Biomass - Wood**	*214.4*	*205.7*	*202.7*	*202.2*	*197.4*	*181.8*	*191.6*
*International Bunker Fuels**	*111.8*	*109.8*	*128.4*	*127.6*	*133.7*	*122.3*	*127.8*
*Biomass – Ethanol**	*4.2*	*22.9*	*31.0*	*38.9*	*54.7*	*62.3*	*74.5*
CH_4	**327.1**	**291.2**	**319.1**	**307.0**	**323.5**	**335.1**	**332.3**
Natural Gas Systems	189.6	190.5	217.7	205.3	212.7	220.9	215.4

[53] Estimates are presented in units of teragrams of carbon dioxide equivalent (Tg CO_2 Eq.), which weight each gas by its global warming potential, or GWP, value. See section on global warming potentials in the Executive Summary.

[54] Global CO_2 emissions from fossil fuel combustion were taken from Energy Information Administration *International Energy Statistics 2010* < http://tonto.eia.doe.gov/cfapps/ipdbproject/IEDIndex3.cfm> EIA (2010).

Coal Mining	84.1	56.8	58.1	57.8	66.9	70.1	72.6
Petroleum Systems	35.2	29.2	29.2	29.8	30.0	30.7	31.0
Stationary Combustion	7.5	6.6	6.2	6.5	6.6	6.3	6.3
Abandoned Underground Coal Mines	6.0	5.5	5.5	5.3	5.3	5.1	5.0
Mobile Combustion	4.7	2.5	2.4	2.2	2.1	2.0	1.9
Incineration of Waste	+	+	+	+	+	+	+
*International Bunker Fuels**	*0.2*	*0.1*	*0.2*	*0.2*	*0.2*	*0.1*	*0.2*
N_2O	**56.7**	**58.0**	**54.8**	**50.6**	**46.7**	**43.6**	**43.6**
Mobile Combustion	43.9	37.0	33.7	29.0	25.2	22.5	20.6
Stationary Combustion	12.3	20.6	20.8	21.2	21.1	20.7	22.6
Incineration of Waste	0.5	0.4	0.4	0.4	0.4	0.4	0.4
*International Bunker Fuels**	*1.1*	*1.0*	*1.2*	*1.2*	*1.2*	*1.1*	*1.2*
Total	**5,287.7**	**6,282.4**	**6,214.4**	**6,294.3**	**6,125.4**	**5,752.7**	**5,933.5**

+ Does not exceed 0.05 Tg CO_2 Eq.

* These values are presented for informational purposes only, in line with IPCC methodological guidance and UNFCCC reporting obligations, and are not included in the specific energy sector contribution to the totals, and are already accounted for elsewhere.

Note: Totals may not sum due to independent rounding.

Table 3-2: CO_2, CH_4, and N_2O Emissions from Energy (Gg)

Gas/Source	1990	2005	2006	2007	2008	2009	2010
CO_2	**4,903,922**	**5,933,252**	**5,840,384**	**5,936,724**	**5,755,172**	**5,374,077**	**5,557,611**
Fossil Fuel Combustion	4,738,338	5,746,480	5,653,032	5,757,775	5,571,537	5,206,168	5,387,790
Non-Energy Use of Fuels	119,627	144,098	143,761	134,863	138,624	123,712	125,130
Natural Gas Systems	37,574	29,901	30,754	31,049	32,826	32,169	32,301
Incineration of Waste	7,989	12,468	12,531	12,727	11,888	11,703	12,054
Petroleum Systems	394	305	306	310	297	325	337
*Biomass -Wood**	*214,410*	*205,671*	*202,680*	*202,204*	*197,358*	*181,806*	*191,591*
*International Bunker Fuels**	*111,828*	*109,765*	*128,413*	*127,643*	*133,730*	*122,338*	*127,841*
*Biomass - Ethanol**	*4,227*	*22,943*	*30,985*	*38,924*	*54,739*	*62,272*	*74,519*
CH_4	**15,575**	**13,864**	**15,196**	**14,619**	**15,405**	**15,955**	**15,825**
Natural Gas Systems	9,029	9,071	10,369	9,774	10,127	10,519	10,259
Coal Mining	4,003	2,705	2,768	2,754	3,186	3,340	3,458
Petroleum Systems	1,677	1,390	1,389	1,420	1,427	1,460	1,478
Stationary Combustion	355	315	296	311	313	298	301
Abandoned Underground Coal Mines	288	264	261	254	253	244	237
Mobile Combustion	223	121	114	107	99	93	91
Incineration of Waste	+	+	+	+	+	+	+
*International Bunker Fuels**	*8*	*7*	*8*	*8*	*8*	*7*	*8*
N_2O	**183**	**187**	**177**	**163**	**151**	**141**	**141**
Mobile Combustion	142	119	109	94	81	73	66
Stationary Combustion	40	66	67	68	68	67	73
Incineration of Waste	2	1	1	1	1	1	1
*International Bunker Fuels**	*3*	*3*	4	4	4	4	4

+ Does not exceed 0.05 Tg CO_2 Eq.

* These values are presented for informational purposes only, in line with IPCC methodological guidance and UNFCCC reporting obligations, and are not included in the specific energy sector contribution to the totals, and are already accounted for elsewhere.

Note: Totals may not sum due to independent rounding.

[BEGIN BOX]

Box 3 1: Energy Data from the Greenhouse Gas Reporting Program

On October 30, 2009, the U.S. Environmental Protection Agency (EPA) published a rule for the mandatory reporting of greenhouse gases (GHG) from large GHG emissions sources in the United States. Implementation of 40 CFR Part 98 is referred to as the Greenhouse Gas Reporting Program (GHGRP). 40 CFR part 98 applies to direct greenhouse gas emitters, fossil fuel suppliers, industrial gas suppliers, and facilities that inject CO_2 underground for sequestration or other reasons. Reporting is at the facility level, except for certain suppliers of fossil fuels and industrial greenhouse gases. 40 CFR part 98 requires reporting by 41 industrial categories. In general, the threshold for reporting is 25,000 metric tons or more of CO_2 Eq. per year. For calendar year 2010, the first year in which data were reported, facilities in 29 categories provided in 40 CFR part 98 were required to report their 2010 emissions by the September 30, 2011 reporting deadline. Data reporting by affected facilities included the reporting of emissions from fuel combustion at that affected facility.

The GHGRP dataset and the data presented in this inventory report are complementary and, as indicated in the respective planned improvements sections for source categories in this chapter, EPA is analyzing how to use facility-level GHGRP data to improve the national estimates presented in this inventory. Most methodologies used in the GHGRP are consistent with IPCC, though for the GHGRP, facilities collect detailed information specific to their operations according to detailed measurement standards, which may differ with the more aggregated data collected for the inventory to estimate total, national U.S. emissions. It should be noted that the definitions and provisions for reporting fuel types in the GHGRP may differ from those used in the inventory in meeting the UNFCCC reporting guidelines. In line with the UNFCCC reporting guidelines, the inventory report is a comprehensive accounting of all emissions from fuel types identified in the IPCC guidelines and provides a separate reporting of emissions from biomass. Further information on the reporting categorizations in GHGRP and specific data caveats associated with monitoring methods in the GHGRP has been provided on the GHGRP website.

EPA presents the data collected by the GHGRP through a data publication tool that allows data to be viewed in several formats including maps, tables, charts and graphs for individual facilities or groups of facilities.

[END BOX]

3.1. Fossil Fuel Combustion (IPCC Source Category 1A)

Emissions from the combustion of fossil fuels for energy include the gases CO_2, CH_4, and N_2O. Given that CO_2 is the primary gas emitted from fossil fuel combustion and represents the largest share of U.S. total emissions, CO_2 emissions from fossil fuel combustion are discussed at the beginning of this section. Following that is a discussion of emissions of all three gases from fossil fuel combustion presented by sectoral breakdowns. Methodologies for estimating CO_2 from fossil fuel combustion also differ from the estimation of CH_4 and N_2O emissions from stationary combustion and mobile combustion. Thus, three separate descriptions of methodologies, uncertainties, recalculations, and planned improvements are provided at the end of this section. Total CO_2, CH_4, and N_2O emissions from fossil fuel combustion are presented in Table 3-3 and Table 3-4.

Table 3-3: CO_2, CH_4, and N_2O Emissions from Fossil Fuel Combustion (Tg CO_2 Eq.)

Gas	1990	2005	2006	2007	2008	2009	2010
CO_2	4,738.3	5,746.5	5,653.0	5,757.8	5,571.5	5,206.2	5,387.8
CH_4	12.1	9.1	8.6	8.8	8.7	8.2	8.2
N_2O	56.2	57.6	54.5	50.2	46.4	43.3	43.2
Total	**4,806.7**	**5,813.3**	**5,716.1**	**5,816.8**	**5,626.6**	**5,257.7**	**5,439.3**

Note: Totals may not sum due to independent rounding.

Table 3-4: CO_2, CH_4, and N_2O Emissions from Fossil Fuel Combustion (Gg)

Gas	1990	2005	2006	2007	2008	2009	2010
CO_2	4,738,338	5,746,480	5,653,032	5,757,775	5,571,537	5,206,168	5,387,790
CH_4	578	436	410	417	412	392	392
N_2O	181	186	176	162	150	140	139

Note: Totals may not sum due to independent rounding.

CO_2 from Fossil Fuel Combustion

CO_2 is the primary gas emitted from fossil fuel combustion and represents the largest share of U.S. total greenhouse gas emissions. CO_2 emissions from fossil fuel combustion are presented in Table 3-5. In 2010, CO_2 emissions from fossil fuel combustion increased by 3.7 percent relative to the previous year which represents the largest annual increase in CO_2 emissions from fossil fuel combustion for the twenty-one-year period.[55] The increase in CO_2 emissions from fossil fuel combustion was a result of multiple factors including: (1) an increase in economic output resulting in an increase in energy consumption across all sectors; (2) an increase in the carbon intensity of fuels consumed due to only a slight increase in the price of coal, and a significant increase in the price of petroleum and natural gas; and (3) much warmer summer conditions resulting in an increase in electricity demand. In 2010, CO_2 emissions from fossil fuel combustion were 5,387.8 Tg CO_2 Eq., or 14 percent above emissions in 1990 (see Table 3-5).[56]

Table 3-5: CO_2 Emissions from Fossil Fuel Combustion by Fuel Type and Sector (Tg CO_2 Eq.)

Fuel/Sector	1990	2005	2006	2007	2008	2009	2010
Coal	**1,718.4**	**2,112.3**	**2,076.6**	**2,106.0**	**2,072.5**	**1,834.4**	**1,933.2**
Residential	3.0	0.8	0.6	0.7	0.7	0.7	0.7
Commercial	12.0	9.3	6.2	6.7	6.5	5.9	5.5
Industrial	155.3	115.3	112.6	107.0	102.6	83.3	96.2
Transportation	NE	NE	NE	NE	NE	NE	NE
Electricity Generation	1,547.6	1,983.8	1,953.7	1,987.3	1,959.4	1,740.9	1,827.3
U.S. Territories	0.6	3.0	3.4	4.3	3.3	3.5	3.5
Natural Gas	**1,001.4**	**1,159.6**	**1,151.8**	**1,226.3**	**1,237.9**	**1,216.6**	**1,261.6**
Residential	238.0	262.2	237.3	256.3	265.5	258.8	258.8
Commercial	142.1	162.9	153.8	163.5	171.1	168.9	167.7
Industrial	409.9	381.4	388.2	398.6	401.0	377.3	394.2
Transportation	36.0	33.1	33.1	35.2	36.7	37.9	40.1
Electricity Generation	175.3	318.8	338.0	371.3	361.9	372.2	399.4
U.S. Territories	NO	1.3	1.4	1.4	1.6	1.5	1.5
Petroleum	**2,018.1**	**2,474.2**	**2,424.2**	**2,425.1**	**2,260.8**	**2,154.8**	**2,192.6**
Residential	97.4	94.9	83.6	84.6	83.1	79.4	80.7
Commercial	64.9	51.3	48.5	48.7	47.4	49.7	51.1
Industrial	281.2	319.6	347.3	338.7	302.9	265.9	287.4
Transportation	1,449.9	1,863.5	1,845.0	1,858.7	1,753.2	1,690.0	1,705.4
Electricity Generation	97.5	99.2	54.4	53.9	39.2	33.0	31.3
U.S. Territories	27.2	45.7	45.5	40.4	35.0	36.7	36.7
Geothermal*	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**
Total	**4,738.3**	**5,746.5**	**5,653.0**	**5,757.8**	**5,571.5**	**5,206.2**	**5,387.8**

NE (Not estimated)

* 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

[55] This increase also represents the largest absolute and percentage increase since 1988 (EIA 2011a).

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

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, size of houses, and number 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.[57] Table 3-6 shows annual changes in emissions during the last five years for coal, petroleum, and natural gas in selected sectors.

Table 3-6: Annual Change in CO_2 Emissions and Total 2010 Emissions from Fossil Fuel Combustion for Selected Fuels and Sectors (Tg CO_2 Eq. and Percent)

Sector	Fuel Type	2006 to 2007		2007 to 2008		2008 to 2009		2009 to 2010		Total 2010
Electricity Generation	Coal	33.6	1.7%	-27.9	-1.4%	-218.5	-11.2%	86.4	5.0%	1,827.3
Electricity Generation	Natural Gas	33.3	9.9%	-9.3	-2.5%	10.3	2.8%	27.2	7.3%	399.4
Electricity Generation	Petroleum	-0.5	-0.9%	-14.7	-27.2%	-6.3	-15.9%	-1.7	-5.2%	31.3
Transportation[a]	Petroleum	13.7	0.7%	-105.6	-5.7%	-63.1	-3.6%	15.4	0.9%	1,705.4
Residential	Natural Gas	19.0	8.0%	9.3	3.6%	-6.7	-2.5%	0.0	0.0%	258.8
Commercial	Natural Gas	9.7	6.3%	7.6	4.6%	-2.2	-1.3%	-1.2	-0.7%	167.7
Industrial	Coal	-5.6	-5.0%	-4.4	-4.1%	-19.3	-18.8%	12.8	15.4%	96.2
Industrial	Natural Gas	10.4	2.7%	2.4	0.6%	-23.7	-5.9%	16.9	4.5%	394.2
All Sectors[b]	**All Fuels[b]**	**104.7**	**1.9%**	**-186.2**	**-3.2%**	**-365.4**	**-6.6%**	**181.6**	**3.5%**	**5,387.8**

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

In the United States, 85 percent of the energy consumed in 2010 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 (9 percent) and by a variety of renewable energy sources[58] (6 percent), primarily hydroelectric power and biofuels (EIA 2011a). Specifically, petroleum supplied the largest share of domestic energy demands, accounting for 41 percent of total fossil fuel based energy consumption in 2010. Natural gas and coal followed in order of energy demand importance, accounting for approximately 32 and 27 percent of total consumption, respectively. Petroleum was consumed primarily in the transportation end-use sector and the vast majority of coal was used in electricity generation. Natural gas was broadly consumed in all end-use sectors except transportation (see Figure 3-5) (EIA 2011a).

Figure 3-3: 2010 U.S. Energy Consumption by Energy Source

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

Figure 3-5: 2010 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

[57] Based on national aggregate carbon content of all coal, natural gas, and petroleum fuels combusted in the United States.
[58] Renewable energy, as defined in EIA's energy statistics, includes the following energy sources: hydroelectric power, geothermal energy, biofuels, solar energy, and wind energy

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.[59] These other C containing non-CO_2 gases are emitted as a byproduct of incomplete fuel combustion, but are, for the most part, eventually oxidized to CO_2 in the atmosphere. Therefore, it is assumed that all of the C in fossil fuels used to produce energy is eventually converted to atmospheric CO_2.

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

In 2010, weather conditions remained fairly constant in the winter and much hotter in the summer compared to 2009, as heating degree days decreased slightly (0.7 percent) and cooling degree days increased by 19 percent. This increase in cooling degree days led to an increase in electricity demand to cool homes. Winter conditions were relatively constant in 2010 compared to 2009, and the winter was slightly warmer than normal, with heating degree days in the United States 1.4 percent below normal (see Figure 3-6). Summer conditions were much warmer in 2010 compared to 2009, and summer temperatures were much warmer than normal, with cooling degree days 17 percent above normal (see Figure 3-7) (EIA 2011a).[60]

Figure 3-6: Annual Deviations from Normal Heating Degree Days for the United States (1950–2010)

Figure 3-7: Annual Deviations from Normal Cooling Degree Days for the United States (1950–2010)

Although no new U.S. nuclear power plants have been constructed in recent years, the utilization (i.e., capacity factors[61]) of existing plants in 2010 remained high at just over 91 percent. Electricity output by hydroelectric power plants decreased in 2010 by approximately 6.0 percent. Electricity generated by nuclear plants in 2010 provided more than 3 times as much of the energy consumed in the United States as hydroelectric plants (EIA 2011a). Nuclear, hydroelectric, and wind power capacity factors since 1990 are shown in Figure 3-8.

Figure 3-8: Nuclear, Hydroelectric, and Wind Power Plant Capacity Factors in the United States (1990–2010)

[END BOX]

Fossil Fuel Combustion Emissions by Sector

In addition to the CO_2 emitted from fossil fuel combustion, CH_4 and N_2O are emitted from stationary and mobile combustion as well. Table 3-7 provides an overview of the CO_2, CH_4, and N_2O emissions from fossil fuel combustion by sector.

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

[60] 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).

[61] The capacity factor equals generation divided by net summer capacity. Summer capacity is defined as "The maximum output that generating equipment can supply to system load, as demonstrated by a multi-hour test, at the time of summer peak demand (period of June 1 through September 30)." Data for both the generation and net summer capacity are from EIA (2011a).

Table 3-7: CO_2, CH_4, and N_2O Emissions from Fossil Fuel Combustion by Sector (Tg CO_2 Eq.)

End-Use Sector	1990	2005	2006	2007	2008	2009	2010
Electricity Generation	**1,828.5**	**2,418.6**	**2,363.1**	**2,430.0**	**2,378.2**	**2,163.7**	**2,277.3**
CO_2	1,820.8	2,402.1	2,346.4	2,412.8	2,360.9	2,146.4	2,258.4
CH_4	0.3	0.5	0.5	0.5	0.5	0.4	0.5
N_2O	7.4	16.0	16.2	16.7	16.9	16.9	18.5
Transportation	**1,534.6**	**1,936.1**	**1,914.2**	**1,925.1**	**1,817.1**	**1,752.4**	**1,768.0**
CO_2	1,485.9	1,896.6	1,878.1	1,893.9	1,789.8	1,727.9	1,745.5
CH_4	4.7	2.5	2.4	2.2	2.1	2.0	1.9
N_2O	43.9	37.0	33.7	29.0	25.2	22.5	20.6
Industrial	**851.3**	**821.0**	**852.9**	**849.0**	**810.8**	**730.4**	**782.0**
CO_2	846.4	816.4	848.1	844.4	806.5	726.6	777.8
CH_4	1.6	1.5	1.5	1.5	1.4	1.2	1.4
N_2O	3.3	3.1	3.2	3.1	2.9	2.5	2.8
Residential	**344.1**	**362.5**	**325.6**	**346.2**	**354.0**	**343.5**	**344.7**
CO_2	338.3	357.9	321.5	341.6	349.3	339.0	340.2
CH_4	4.6	3.6	3.3	3.6	3.7	3.6	3.5
N_2O	1.1	1.0	0.9	0.9	1.0	0.9	0.9
Commercial	**220.2**	**224.8**	**209.8**	**220.1**	**226.4**	**225.9**	**225.5**
CO_2	219.0	223.5	208.6	218.9	225.1	224.6	224.2
CH_4	0.9	0.9	0.9	0.9	0.9	1.0	0.9
N_2O	0.4	0.4	0.3	0.3	0.3	0.3	0.3
U.S. Territories*	**28.0**	**50.2**	**50.5**	**46.3**	**40.0**	**41.8**	**41.8**
Total	**4,806.7**	**5,813.3**	**5,716.1**	**5,816.8**	**5,626.6**	**5,257.7**	**5,439.3**

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.

* U.S. Territories are not apportioned by sector, and emissions are total greenhouse gas emissions from all fuel combustion sources.

Other than CO_2, gases emitted from stationary combustion include the greenhouse gases CH_4 and N_2O and the indirect greenhouse gases NO_x, CO, and NMVOCs.[62] Methane and N_2O emissions from stationary combustion sources depend upon fuel characteristics, size and vintage, along with combustion technology, pollution control equipment, ambient environmental conditions, and operation and maintenance practices. 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. Methane emissions from stationary combustion are primarily a function of the CH_4 content of the fuel and combustion efficiency.

Mobile combustion produces greenhouse gases other than CO_2, including CH_4, N_2O, and indirect greenhouse gases including NO_x, CO, and NMVOCs. As with stationary combustion, N_2O and NO_x emissions from mobile combustion are closely related to fuel characteristics, air-fuel mixes, combustion temperatures, and the use of pollution control equipment. N_2O from mobile sources, 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. Methane 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).

An alternative method of presenting combustion 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. In the table below, electricity generation emissions have been distributed to each end-use sector based upon the sector's share of national electricity consumption, with the exception of CH_4 and N_2O

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

from transportation.[63] Emissions from U.S. territories are also calculated separately due to a lack of end-use-specific consumption data. This method assumes that emissions from combustion sources are distributed across the four end-use sectors based on the ratio of electricity consumption in that sector. The results of this alternative method are presented in Table 3-8.

Table 3-8: CO_2, CH_4, and N_2O Emissions from Fossil Fuel Combustion by End-Use Sector (Tg CO_2 Eq.)

End-Use Sector	1990	2005	2006	2007	2008	2009	2010
Transportation	**1,537.6**	**1,940.9**	**1,918.8**	**1,930.2**	**1,821.9**	**1,756.9**	**1,772.5**
CO_2	1,489.0	1,901.3	1,882.6	1,899.0	1,794.5	1,732.4	1,750.0
CH_4	4.7	2.5	2.4	2.2	2.1	2.0	1.9
N_2O	44.0	37.0	33.7	29.0	25.3	22.5	20.6
Industrial	**1,540.9**	**1,563.0**	**1,570.0**	**1,569.5**	**1,513.2**	**1,337.2**	**1,424.9**
CO_2	1,533.1	1,553.3	1,560.2	1,559.8	1,503.8	1,328.6	1,415.4
CH_4	1.7	1.7	1.7	1.6	1.5	1.4	1.5
N_2O	6.1	8.1	8.2	8.1	7.9	7.2	8.0
Residential	**939.6**	**1,225.1**	**1,162.4**	**1,215.8**	**1,203.1**	**1,136.3**	**1,195.2**
CO_2	931.4	1,214.7	1,152.4	1,205.2	1,192.2	1,125.5	1,183.7
CH_4	4.7	3.8	3.4	3.8	3.9	3.8	3.7
N_2O	3.5	6.7	6.6	6.9	7.0	7.1	7.8
Commercial	**760.5**	**1,034.0**	**1,014.5**	**1,054.9**	**1,048.4**	**985.4**	**1,004.9**
CO_2	757.0	1,027.2	1,007.6	1,047.7	1,041.1	978.0	997.1
CH_4	1.0	1.1	1.0	1.1	1.1	1.1	1.1
N_2O	2.6	5.7	5.9	6.1	6.2	6.3	6.7
U.S. Territories*	**28.0**	**50.2**	**50.5**	**46.3**	**40.0**	**41.8**	**41.8**
Total	**4,806.7**	**5,813.3**	**5,716.1**	**5,816.8**	**5,626.6**	**5,257.7**	**5,439.3**

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.

* U.S. Territories are not apportioned by sector, and emissions are total greenhouse gas emissions from all fuel combustion sources.

Stationary Combustion

The direct combustion of fuels by stationary sources in the electricity generation, industrial, commercial, and residential sectors represent the greatest share of U.S. greenhouse gas emissions. Table 3-9 presents CO_2 emissions from fossil fuel combustion by stationary sources. The CO_2 emitted is closely linked to the type of fuel being combusted in each sector (see Methodology section for CO_2 from fossil fuel combustion). Other than CO_2, gases emitted from stationary combustion include the greenhouse gases CH_4 and N_2O. Table 3-10 and Table 3-11 present CH_4 and N_2O emissions from the combustion of fuels in stationary sources. [64] Methane and N_2O emissions from stationary combustion sources depend upon fuel characteristics, combustion technology, pollution control equipment, ambient environmental conditions, and operation and maintenance practices. 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. Methane emissions from stationary combustion are primarily a function of the CH_4 content of the fuel and combustion efficiency. The CH_4 and N_2O emission estimation methodology was revised in 2010 to utilize the facility-specific technology and fuel use data reported to EPA's Acid Rain Program (see Methodology section for CH_4 and N_2O from stationary combustion). Please refer to Table 3-7 for the corresponding presentation of all direct emission sources of fuel combustion.

Table 3-9: CO_2 Emissions from Stationary Fossil Fuel Combustion (Tg CO_2 Eq.)

[63] Separate calculations were performed for transportation-related CH_4 and N_2O. The methodology used to calculate these emissions are discussed in the mobile combustion section.

[64] Since emissions estimates for U.S. territories cannot be disaggregated by gas in Table 3-10 and Table 3-11, the percentages for CH_4 and N_2O exclude U.S. territory estimates.

Sector/Fuel Type	1990	2005	2006	2007	2008	2009	2010
Electricity Generation	**1,820.8**	**2,402.1**	**2,346.4**	**2,412.8**	**2,360.9**	**2,146.4**	**2,258.4**
Coal	1,547.6	1,983.8	1,953.7	1,987.3	1,959.4	1,740.9	1,827.3
Natural Gas	175.3	318.8	338.0	371.3	361.9	372.2	399.4
Fuel Oil	97.5	99.2	54.4	53.9	39.2	33.0	31.3
Geothermal	0.4	0.38	0.37	0.38	0.38	0.38	0.40
Industrial	**846.4**	**816.4**	**848.1**	**844.4**	**806.5**	**726.6**	**777.8**
Coal	155.3	115.3	112.6	107.0	102.6	83.3	96.2
Natural Gas	409.9	381.4	388.2	398.6	401.0	377.3	394.2
Fuel Oil	281.2	319.6	347.3	338.7	302.9	265.9	287.4
Commercial	**219.0**	**223.5**	**208.6**	**218.9**	**225.1**	**224.6**	**224.2**
Coal	12.0	9.3	6.2	6.7	6.5	5.9	5.5
Natural Gas	142.1	162.9	153.8	163.5	171.1	168.9	167.7
Fuel Oil	64.9	51.3	48.5	48.7	47.4	49.7	51.1
Residential	**338.3**	**357.9**	**321.5**	**341.6**	**349.3**	**339.0**	**340.2**
Coal	3.0	0.8	0.6	0.7	0.7	0.7	0.7
Natural Gas	238.0	262.2	237.3	256.3	265.5	258.8	258.8
Fuel Oil	97.4	94.9	83.6	84.6	83.1	79.4	80.7
U.S. Territories	**27.9**	**50.0**	**50.3**	**46.1**	**39.8**	**41.7**	**41.6**
Coal	0.6	3.0	3.4	4.3	3.3	3.5	3.5
Natural Gas	NO	1.3	1.4	1.4	1.6	1.5	1.5
Fuel Oil	27.2	45.7	45.5	40.4	35.0	36.7	36.7
Total	**3,252.4**	**3,849.9**	**3,774.9**	**3,863.9**	**3,781.7**	**3,478.3**	**3,642.3**

* U.S. Territories are not apportioned by sector, and emissions are from all fuel combustion sources (stationary and mobile) are presented in this table.

Table 3-10: CH_4 Emissions from Stationary Combustion (Tg CO_2 Eq.)

Sector/Fuel Type	1990	2005	2006	2007	2008	2009	2010
Electricity Generation	**0.3**	**0.5**	**0.5**	**0.5**	**0.5**	**0.4**	**0.5**
Coal	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Fuel Oil	+	+	+	+	+	+	+
Natural Gas	0.1	0.1	0.1	0.1	0.1	0.1	0.2
Wood	+	+	+	+	+	+	+
Industrial	**1.6**	**1.5**	**1.5**	**1.5**	**1.4**	**1.2**	**1.4**
Coal	0.3	0.3	0.3	0.2	0.2	0.2	0.2
Fuel Oil	0.2	0.2	0.2	0.2	0.2	0.1	0.1
Natural Gas	0.2	0.1	0.1	0.1	0.2	0.1	0.1
Wood	0.9	0.9	1.0	0.9	0.9	0.8	0.9
Commercial	**0.9**	**0.9**	**0.9**	**0.9**	**0.9**	**1.0**	**0.9**
Coal	+	+	+	+	+	+	+
Fuel Oil	0.2	0.2	0.1	0.1	0.1	0.1	0.2
Natural Gas	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Wood	0.4	0.5	0.4	0.5	0.5	0.5	0.5
Residential	**4.6**	**3.6**	**3.3**	**3.6**	**3.7**	**3.6**	**3.5**
Coal	0.2	0.1	+	+	+	+	+
Fuel Oil	0.3	0.3	0.3	0.3	0.3	0.2	0.3
Natural Gas	0.4	0.5	0.4	0.5	0.5	0.5	0.5
Wood	3.7	2.8	2.5	2.8	2.9	2.8	2.7
U.S. Territories	**+**	**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	**7.5**	**6.6**	**6.2**	**6.5**	**6.6**	**6.3**	**6.3**

+ Does not exceed 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding.

Table 3-11: N_2O Emissions from Stationary Combustion (Tg CO_2 Eq.)

Sector/Fuel Type	1990	2005	2006	2007	2008	2009	2010
Electricity Generation	**7.4**	**16.0**	**16.2**	**16.7**	**16.8**	**16.8**	**18.5**
Coal	6.3	11.6	11.5	11.4	11.6	11.2	12.5
Fuel Oil	0.1	0.1	0.1	0.1	+	+	+
Natural Gas	1.0	4.3	4.7	5.2	5.2	5.6	5.9
Wood	+	+	+	+	+	+	+
Industrial	**3.3**	**3.1**	**3.2**	**3.1**	**2.9**	**2.5**	**2.8**
Coal	0.8	0.6	0.6	0.5	0.5	0.4	0.5
Fuel Oil	0.5	0.5	0.6	0.6	0.5	0.4	0.4
Natural Gas	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Wood	1.8	1.9	1.9	1.8	1.7	1.5	1.7
Commercial	**0.4**	**0.4**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**
Coal	0.1	+	+	+	+	+	+
Fuel Oil	0.2	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
Wood	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Residential	**1.1**	**1.0**	**0.9**	**0.9**	**1.0**	**0.9**	**0.9**
Coal	+	+	+	+	+	+	+
Fuel Oil	0.3	0.3	0.2	0.2	0.2	0.2	0.2
Natural Gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wood	0.7	0.6	0.5	0.5	0.6	0.6	0.5
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	0.1
Natural Gas	+	+	+	+	+	+	+
Wood	+	+	+	+	+	+	+
Total	**12.3**	**20.6**	**20.8**	**21.2**	**21.1**	**20.7**	**22.6**

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

Electricity Generation

The process of generating electricity is the single largest source of CO_2 emissions in the United States, representing 42 percent of total CO_2 emissions from all CO_2 emissions sources across the United States. Methane and N_2O accounted for a small portion of emissions from electricity generation, representing less than 0.1 percent and 0.8 percent, respectively. Electricity generation also accounted for the largest share of CO_2 emissions from fossil fuel combustion, approximately 42 percent in 2010. Methane and N_2O from electricity generation represented 6 and 43 percent of emissions from CH_4 and N_2O emissions from fossil fuel combustion in 2010, respectively. 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 3-9).

Figure 3-9: 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) places 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,[65] while the other sectors consist of those producers that indicate their primary business is something other than the production of electricity.

The industrial, residential, and commercial end-use sectors, as presented in Table 3-8, were reliant on electricity for meeting energy needs. The residential and commercial end-use sectors were especially reliant on electricity consumption for lighting, heating, air conditioning, and operating appliances. Electricity sales to the residential and commercial end-use sectors in 2010 increased approximately 6.3 percent and 1.7 percent, respectively. The trend in the residential and commercial sectors can largely be attributed to warmer, more energy-intensive summer weather conditions compared to 2009. Electricity sales to the industrial sector in 2010 increased approximately 5.0 percent. Overall, in 2010, the amount of electricity generated (in kWh) increased by 4.3 percent from the previous year. This increase was due to an increase in economic output, an increase in the carbon intensity of fuels used to generate electricity due to fuel switching as the price of coal only slightly increased, and the price of petroleum and natural gas increased significantly, and a slight decrease in the contribution of non-fossil fuel sources used to generate electricity. As a result, CO_2 emissions from the electric power sector increased by 5.2 percent as the consumption of coal and natural gas for electricity generation increased by 5.0 percent and 7.3 percent, respectively, in 2010 and the consumption of petroleum for electricity generation, decreased by 6.1 percent.

Industrial Sector

The industrial sector accounted for 15 percent of CO_2 emissions from fossil fuel combustion, 17 percent of CH_4 emissions from fossil fuel combustion, and 6 percent of N_2O emissions from fossil fuel combustion. CO_2, CH_4, and N_2O emissions resulted from the direct consumption of fossil fuels for steam and process heat production.

The industrial 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, Paper, Primary Metals, Food, and Nonmetallic Mineral Products—represent the vast majority of the energy use (EIA 2011a and EIA 2009c).

In theory, emissions from the industrial sector should be highly correlated with economic growth and industrial

[65] 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).

output, but heating of industrial buildings and agricultural energy consumption are also affected by weather conditions.[66] 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 effect on industrial emissions.

From 2009 to 2010, total industrial production and manufacturing output increased by 5.3 and 5.8 percent, respectively (FRB 2011). Over this period, output increased across all production indices for Food, Petroleum Refineries, Chemicals, Paper, Primary Metals, and Nonmetallic Mineral Products (see Figure 3-10).

Figure 3-10: Industrial Production Indices (Index 2007=100)

Despite the growth in industrial output (45 percent) and the overall U.S. economy (63 percent) from 1990 to 2010, CO_2 emissions from fossil fuel combustion in the industrial sector decreased by 8.1 percent over that time. A number of factors are believed to have caused this disparity between 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) energy-intensive industries such as steel are employing new methods, such as electric arc furnaces, that are less carbon intensive than the older methods. In 2010, CO_2, CH_4, and N_2O emissions from fossil fuel combustion and electricity use within the industrial end-use sector totaled 1,424.9 Tg CO_2 Eq., or approximately 6.6 percent above 2009 emissions.

Residential and Commercial Sectors

The residential and commercial sectors accounted for 6 and 4 percent of CO_2 emissions from fossil fuel combustion, 43 and 11 percent of CH_4 emissions from fossil fuel combustion, and 2 and 1 percent of N_2O emissions from fossil fuel combustion, respectively. Emissions from these sectors 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 2010, CO_2, CH_4, and N_2O emissions from fossil fuel combustion and electricity use within the residential and commercial end-use sectors were 1,195.2 Tg CO_2 Eq. and 1,004.9 Tg CO_2 Eq., respectively. Total CO_2, CH_4, and N_2O emissions from the residential and commercial sectors increased by 5.2 and 2.0 percent from 2009 to 2010, 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. In the long-term, both 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 about 76 and 75 percent of the direct fossil fuel CO_2 emissions from the residential and commercial sectors, respectively. In 2010, natural gas CO_2 emissions from the residential and commercial sectors remained relatively constant and decreased by 0.3 percent, respectively.

U.S. Territories

Emissions from U.S. territories are based on the fuel consumption in American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands. As described in the Methodology section for CO_2 from fossil fuel combustion, this data is collected separately from the sectoral-level data available for the general calculations. As sectoral information is not available for U.S. Territories, CO_2, CH_4, and N_2O emissions are not presented for U.S. Territories in the tables above, though the emissions will include some transportation and mobile combustion sources.

[66] 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.

Transportation Sector

This discussion of transportation emissions follows the alternative method of presenting combustion emissions by allocating emissions associated with electricity generation to the transportation end-use sector, as presented in Table 3-8. For direct emissions from transportation (i.e., not including emissions associated with the sector's electricity consumption), please see Table 3-7.

Transportation End-Use Sector

The transportation end-use sector accounted for 1,772.5 Tg CO_2 Eq. in 2010, which represented 33 percent of CO_2 emissions, 23 percent of CH_4 emissions, and 48 percent of N_2O emissions from fossil fuel combustion, respectively. Fuel purchased in the U.S. for international aircraft and marine travel accounted for an additional 127.8 Tg CO_2 in 2010; 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 61 percent of CO_2 emissions, medium- and heavy-duty trucks 22 percent, commercial aircraft 7 percent, and other sources 10 percent. Passenger car CO_2 emissions increased by 20 percent from 1990 to 2010, light-duty truck[67] CO_2 emissions decreased by 3 percent and medium- and heavy-duty trucks increased by 74 percent. [68] General aviation aircraft CO_2 emissions also increased by nearly 67 percent (6.5 Tg) from 1990 to 2010. CO_2 from the domestic operation of commercial aircraft decreased by 16 percent (21.4 Tg) from 1990 to 2010. Across all categories of aviation[69], CO_2 emissions decreased by 20.6 percent (36.9 Tg) between 1990 and 2010. This includes a 64 percent (21.9 Tg) decrease in emissions from domestic military operations. For further information on all greenhouse gas emissions from transportation sources, please refer to Annex 3.2. See Table 3-12 for a detailed breakdown of CO_2 emissions by mode and fuel type.

From 1990 to 2010, transportation emissions rose by 19 percent due, in large part, to increased demand for travel and the stagnation of fuel efficiency across the U.S. vehicle fleet. The number of vehicle miles traveled by light-duty motor vehicles (passenger cars and light-duty trucks) increased 34 percent from 1990 to 2010, as a result of a confluence of factors including population growth, economic growth, urban sprawl, and low fuel prices over much of this period.

From 2009 to 2010, CO_2 emissions from the transportation end-use sector increased 0.9 percent. The increase in emissions can largely be attributed to increased economic activity in 2010 and an associated increase in the demand for transportation. Modes such as medium- and heavy-duty trucks were impacted by the increase in freight transport. In contrast, commercial aircraft emissions continued to fall, having decreased 21 percent since 2007, with increased jet fuel prices being a factor.

Almost all of the energy consumed for transportation was supplied by petroleum-based products, with more than half being related to gasoline consumption in automobiles and other highway vehicles. Other fuel uses, especially diesel fuel for freight trucks and jet fuel for aircraft, accounted for the remainder. The primary driver of transportation-related emissions was CO_2 from fossil fuel combustion, which increased by 20 percent from 1990 to 2010. This rise in CO_2 emissions, combined with an increase in HFCs from close to zero emissions in 1990 to 60.2 Tg CO_2 Eq. in 2010, led to an increase in overall emissions from transportation activities of 20 percent.

Transportation Fossil Fuel Combustion CO_2 Emissions

Domestic transportation CO_2 emissions increased by 18 percent (261.0 Tg) between 1990 and 2010, an annualized increase of 0.8 percent. The 1 percent increase in emissions between 2009 and 2010 contrasted with the previous

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[67] Includes "light-duty trucks" fueled by gasoline, diesel and LPG

[68] In 2011 FHWA changed how they defined vehicle types for the purposes of reporting VMT for the years 2007-2010. The old approach to vehicle classification was based on body type and split passenger vehicles into "Passenger Cars" and "Other 2 Axle 4-Tire Vehicles". The new approach is a vehicle classification system based on wheelbase. Vehicles with a wheelbase less than or equal to 121 inches are counted as "Light-duty Vehicles –Short Wheelbase". Passenger vehicles with a Wheelbase greater than 121 inches are counted as "Light-duty Vehicles - Long Wheelbase". This change in vehicle classification has moved some smaller trucks and sport utility vehicles from the light truck category to the passenger vehicle category in this emission inventory. These changes are reflected in a large drop in light-truck emissions between 2006 and 2007.

[69] Includes consumption of jet fuel and aviation gasoline. Does not include aircraft bunkers, which are not included in national emission totals, in line with IPCC methodological guidance and UNFCCC reporting obligations.

year's trend of decreasing emissions. Almost all of the energy consumed by the transportation sector is petroleum-based, including motor gasoline, diesel fuel, jet fuel, and residual oil. [70] Transportation sources also produce CH_4 and N_2O; these emissions are included in Table 3-13 and Table 3-14 in 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 1,073.5 Tg in 2010, an increase of 13 percent (123.1 Tg) from 1990. CO_2 emissions from passenger cars and light-duty trucks peaked at 1,184.3 Tg in 2004, and since then have declined about 9 percent. Over the 1990s through early this decade, growth in vehicle travel substantially outweighed improvements in vehicle fuel economy; however, the rate of Vehicle Miles Traveled (VMT) growth slowed considerably starting in 2005 (and declined rapidly in 2008) while average vehicle fuel economy increased. However, in 2010, fuel VMT grew by 0.3 percent, while average fuel economy decreased slightly. Among new vehicles sold annually, average fuel economy gradually declined from 1990 to 2004 (Figure 3-11), reflecting substantial growth in sales of light-duty trucks—in particular, growth in the market share of sport utility vehicles—relative to passenger cars (Figure 3-12). New vehicle fuel economy improved beginning in 2005, largely due to higher light-duty truck fuel economy standards, which have risen each year since 2005. The overall increase in fuel economy is also due to a slightly lower light-duty truck market share, which peaked in 2004 at 44 percent and declined to 23 percent in 2010.

Figure 3-11: Sales-Weighted Fuel Economy of New Passenger Cars and Light-Duty Trucks, 1990–2010

Figure 3-12: Sales of New Passenger Cars and Light-Duty Trucks, 1990–2010

Table 3-12: CO_2 Emissions from Fossil Fuel Combustion in Transportation End-Use Sector (Tg CO_2 Eq.) [a]

Fuel/Vehicle Type	1990		2005	2006	2007 [e]	2008	2009	2010
Gasoline	**983.7**		**1,187.8**	**1,178.2**	**1,181.2**	**1,130.3**	**1,128.5**	**1,117.0**
Passenger Cars	621.4		658.0	635.0	800.2	765.5	762.4	753.8
Light-Duty Trucks	309.1		478.8	491.5	315.5	298.9	304.1	302.2
Medium- and Heavy-Duty Trucks [b]	38.7		34.9	35.5	46.6	47.2	43.6	43.4
Buses	0.3		0.4	0.4	0.7	0.8	0.8	0.7
Motorcycles	1.7		1.6	1.9	4.3	4.4	4.2	3.7
Recreational Boats	12.4		14.1	14.0	13.9	13.5	13.3	13.1
Distillate Fuel Oil (Diesel)	**262.9**		**458.1**	**470.3**	**476.3**	**443.5**	**402.9**	**418.9**
Passenger Cars	7.9		4.2	4.1	4.1	3.7	3.6	3.7
Light-Duty Trucks	11.5		25.8	26.8	13.6	12.1	12.1	12.6
Medium- and Heavy-Duty Trucks [b]	190.5		360.7	370.0	384.6	366.1	332.2	345.3
Buses	8.0		10.6	10.8	15.9	15.2	14.1	14.0
Rail	35.5		45.6	47.8	46.6	43.2	36.3	39.0
Recreational Boats	2.0		3.1	3.2	3.3	0.9	3.5	3.5
Ships and Other Boats	7.5		8.1	7.5	8.2	2.2	1.2	0.7
International Bunker Fuels [c]	*11.7*		*9.4*	*8.8*	*8.2*	*9.0*	*8.3*	*8.8*
Jet Fuel	**176.2**		**194.2**	**169.5**	**168.7**	**155.1**	**139.6**	**140.5**
Commercial Aircraft	135.4		161.2	137.1	138.1	122.2	111.4	114.0
Military Aircraft	34.4		18.1	16.3	16.1	16.2	14.1	12.5
General Aviation	6.4		14.9	16.0	14.5	16.6	14.1	14.0

[70] Biofuel estimates are presented for informational purposes only in the Energy chapter, in line with IPCC methodological guidance and UNFCCC reporting obligations. Net carbon fluxes from changes in biogenic carbon reservoirs in croplands are accounted for in the estimates for Land Use, Land-Use Change, and Forestry (see Chapter 7). More information and additional analyses on biofuels are available at EPA's "Renewable Fuels: Regulations & Standards" web page: http://www.epa.gov/otaq/fuels/renewablefuels/regulations.htm

Aircraft							
International Bunker Fuels [c]	*46.4*	*56.8*	*74.6*	*73.8*	*75.5*	*68.6*	*72.5*
Aviation Gasoline	3.1	2.4	2.3	2.2	2.0	1.8	1.9
General Aviation Aircraft	3.1	2.4	2.3	2.2	2.0	1.8	1.9
Residual Fuel Oil	**22.6**	**19.3**	**23.0**	**29.0**	**19.9**	**15.4**	**25.3**
Ships and Other Boats	22.6	19.3	23.0	29.0	19.9	15.4	25.3
International Bunker Fuels [c]	*53.7*	*43.6*	*45.0*	*45.6*	*49.2*	*45.4*	*46.5*
Natural Gas	**36.0**	**33.1**	**33.1**	**35.2**	**36.7**	**37.9**	**40.1**
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+
Buses	+	0.8	0.8	1.0	1.1	1.3	1.3
Pipeline	36.0	32.2	32.3	34.2	35.6	36.6	38.8
LPG	**1.4**	**1.7**	**1.7**	**1.4**	**2.5**	**1.7**	**1.8**
Light-Duty Trucks	0.6	1.3	1.2	1.0	1.8	1.2	1.2
Medium- and Heavy-Duty Trucks[b]	0.8	0.4	0.5	0.4	0.7	0.5	0.6
Buses	+	+	+	+	+	+	+
Electricity	**3.0**	**4.7**	**4.5**	**5.1**	**4.7**	**4.5**	**4.5**
Rail	3.0	4.7	4.5	5.1	4.7	4.5	4.5
Total	**1,489.0**	**1,901.3**	**1,882.6**	**1,899.0**	**1,794.5**	**1,732.4**	**1,750.0**
Total (Including Bunkers) [c]	**1,600.8**	**2,011.1**	**2,011.1**	**2,026.6**	**1,928.3**	**1,854.7**	**1,877.8**

[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] 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.
[d] Residual fuel oil data for ships and boats is based on EIA's December 2011 Monthly Energy Review
[e] In 2011, FHWA changed how vehicles are classified, moving form a system based on body-type to one that is based on wheelbase. This change in methodology in FHWA's VM-1 table resulted in large changes in fuel consumption data by vehicle class, thus leading to a shift in emissions among on-road vehicle classes in the 2007-2010 time period. Note: Totals may not sum due to independent rounding.
Note: See section 3.10 of this chapter, in line with IPCC methodological guidance and UNFCCC reporting obligations, for more information on ethanol.
+ Less than 0.05 Tg CO_2 Eq.
- Unreported or zero

Mobile Fossil Fuel Combustion CH_4 and N_2O Emissions

Mobile combustion includes emissions of CH_4 and N_2O from 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 (e.g., snowmobiles, lawnmowers, etc.). Annex 3.2 includes a summary of all emissions from both transportation and mobile sources. Table 3-13 and Table 3-14 provide CH_4 and N_2O emission estimates in Tg CO_2 Eq.[71]

Mobile combustion was responsible for a small portion of national CH_4 emissions (0.3 percent) but was the second largest source of U.S. N_2O emissions (7 percent). From 1990 to 2010, mobile source CH_4 emissions declined by 59 percent, to 1.9 Tg CO_2 Eq. (91 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 53 percent, to 20.6 Tg CO_2 Eq. (66 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

[71] See Annex 3.2 for a complete time series of emission estimates for 1990 through 2010.

later-generation emission control technologies have reduced N_2O output, resulting in a 63 percent decrease in mobile source N_2O emissions from 1998 to 2010 (Figure 3-13). Overall, CH_4 and N_2O emissions were predominantly from gasoline-fueled passenger cars and light-duty trucks.

Figure 3-13: Mobile Source CH_4 and N_2O Emissions

Table 3-13: CH_4 Emissions from Mobile Combustion (Tg CO_2 Eq.)

Fuel Type/Vehicle Type[a]	1990	2005	2006	2007[e]	2008	2009	2010
Gasoline On-Road	**4.2**	**1.9**	**1.7**	**1.6**	**1.4**	**1.3**	**1.2**
Passenger Cars	2.6	1.1	1.0	1.1	1.0	0.9	0.9
Light-Duty Trucks	1.4	0.7	0.6	0.3	0.3	0.3	0.3
Medium- and Heavy-Duty Trucks and Buses	0.2	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**	**0.1**	**0.1**	**0.1**
Non-Road	**0.4**	**0.6**	**0.6**	**0.5**	**0.5**	**0.5**	**0.4**
Ships and Boats	+	+	+	+	+	+	+
Rail	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Aircraft	0.2	0.2	0.1	0.1	0.1	0.1	0.1
Agricultural Equipment[b]	0.1	0.1	0.1	0.1	0.1	0.1	+
Construction/Mining Equipment[c]	+	0.1	0.1	0.1	0.1	0.1	0.1
Other[d]	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**4.7**	**2.5**	**2.4**	**2.2**	**2.1**	**2.0**	**1.9**

[a] See Annex 3.2 for definitions of on-road vehicle types.
[b] Includes equipment, such as tractors and combines, as well as fuel consumption from trucks that are used off-road in agriculture.
[c] Includes equipment, such as cranes, dumpers, and excavators, as well as fuel consumption from trucks that are used off-road in construction.
[d] "Other" includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment, as well as fuel consumption from trucks that are used off-road for commercial/industrial purposes.
[e] In 2011, FHWA changed how vehicles are classified, moving from a system based on body-type to one that is based on wheelbase. This change in methodology in FHWA's VM-1 table resulted in large changes in VMT by vehicle class, thus leading to a shift in emissions among on-road vehicle classes in the 2007 to 2010 time period.
Note: Totals may not sum due to independent rounding.
+ Less than 0.05 Tg CO_2 Eq.

Table 3-14: N_2O Emissions from Mobile Combustion (Tg CO_2 Eq.)

Fuel Type/Vehicle Type[a]	1990	2005	2006	2007[e]	2008	2009	2010
Gasoline On-Road	**40.1**	**32.1**	**29.0**	**24.1**	**20.7**	**18.3**	**16.1**
Passenger Cars	25.4	17.8	15.7	17.3	14.6	12.4	10.8
Light-Duty Trucks	14.1	13.6	12.6	5.8	5.2	5.1	4.6
Medium- and Heavy-Duty Trucks and Buses	0.6	0.8	0.7	0.9	0.9	0.6	0.6
Motorcycles	+	+	+	+	+	+	+
Diesel On-Road	**0.2**	**0.3**	**0.3**	**0.4**	**0.4**	**0.4**	**0.4**
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+

Medium- and Heavy-Duty Trucks and Buses	0.2		0.3	0.3	0.4	0.4	0.4	0.4
Alternative Fuel On-Road	**0.1**		**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**
Non-Road	**3.6**		**4.3**	**4.2**	**4.3**	**3.8**	**3.6**	**3.8**
Ships and Boats	0.6		0.6	0.7	0.8	0.5	0.5	0.6
Rail	0.3		0.4	0.4	0.4	0.3	0.3	0.3
Aircraft	1.7		1.9	1.6	1.6	1.5	1.3	1.3
Agricultural Equipment[b]	0.2		0.4	0.4	0.4	0.4	0.4	0.4
Construction/Mining Equipment[c]	0.3		0.5	0.5	0.5	0.5	0.5	0.6
Other[d]	0.4		0.6	0.6	0.6	0.6	0.6	0.6
Total	**43.9**		**37.0**	**33.7**	**29.0**	**25.2**	**22.5**	**20.6**

[a] See Annex 3.2 for definitions of on-road vehicle types.
[b] Includes equipment, such as tractors and combines, as well as fuel consumption from trucks that are used off-road in agriculture.
[c] Includes equipment, such as cranes, dumpers, and excavators, as well as fuel consumption from trucks that are used off-road in construction.
[d] "Other" includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment, as well as fuel consumption from trucks that are used off-road for commercial/industrial purposes.
[e] In 2011, FHWA changed how vehicles are classified, moving from a system based on body-type to one that is based on wheelbase. This change in methodology in FHWA's VM-1 table resulted in large changes in VMT by vehicle class, thus leading to a shift in emissions among on-road vehicle classes in the 2007 to 2010 time period.
Note: Totals may not sum due to independent rounding.
+ Less than 0.05 Tg CO_2 Eq.

CO_2 from Fossil Fuel Combustion

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 in line with a Tier 2 method in the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (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 2011b). The EIA does not include territories in its national energy statistics, so fuel consumption data for territories were collected separately from Jacobs (2010).[72]

   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 on an annual basis and used in this inventory are predominantly from mid-stream or conversion energy consumers such as refiners and electric power generators. These annual surveys are supplemented with end-use energy consumption surveys, such as the Manufacturing Energy Consumption Survey, that are conducted on a

[72] 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 42 Tg CO_2 Eq. in 2010.

periodic basis (every 4 years). These consumption data sets help inform the annual surveys to arrive at the national total and sectoral breakdowns for that total. [73]

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 standards, which are to report energy statistics in terms of net calorific values (NCV) (i.e., lower heating values).[74]

2. *Subtract uses accounted for in the Industrial Processes chapter.* Portions of the fuel consumption data for seven fuel categories—coking coal, distillate fuel, 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 (2004 through 2011), Coffeyville (2011), U.S. Census Bureau (2011), EIA (2011b), USGS (1991 through 2011), USGS (1994 through 2011), USGS (1995, 1998, 2000 through 2002), USGS (2007), USGS (2009a), USGS (2009b), USGS (2010a), USGS(2010b), USGS (2010c), USGS (2011), USGS (1991 through 2010a), USGS (1991 through 2010b), USGS (2010) and USGS (2011).[75]

3. *Adjust for conversion of fuels and exports of CO_2.* Fossil fuel consumption estimates are adjusted downward to exclude fuels created from other fossil fuels and exports of CO_2.[76] 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.[77] 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 were collected from EIA (2011a), data for synthetic natural gas were collected from EIA (2011b), and data for CO_2 exports were collected from the Eastman Gasification Services Company (2011), Dakota Gasification Company (2006), Fitzpatrick (2002), Erickson (2003), EIA (2007b) and DOE (2012).

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 the Federal Highway Administration's (FHWA) 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 upward to match the value obtained from the bottom-up analysis based on VMT. As the total distillate and motor gasoline consumption estimate from EIA are considered to be accurate at the national level, the distillate consumption totals for the residential, commercial, and industrial sectors were adjusted downward proportionately. The data sources used in the bottom-up analysis of transportation fuel consumption include AAR (2009 through 2011), Benson (2002 through 2004), DOE (1993 through 2011), EIA (2009a), EIA (1991 through 2011), EPA (2009), and FHWA (1996 through 2012).[78]

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[73] 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.

[74] 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.

[75] See sections on Iron and Steel Production and Metallurgical Coke Production, Ammonia Production and Urea Consumption, Petrochemical Production, Titanium Dioxide Production, Ferroalloy Production, Aluminum Production, and Silicon Carbide Production and Consumption in the Industrial Processes chapter.

[76] Energy statistics from EIA (2012) are already adjusted downward to account for ethanol added to motor gasoline, and biogas in natural gas.

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

[78] The source of VMT and fuel consumption is FHWA's VM-1 table. The data collection methodology has undergone substantial revision for only years 2007 to 2010, while prior years have remain unchanged Several of the vehicle type categories have changed. For instance, passenger car has been replaced by "Light duty vehicle, short WB" and other 4 axle- 2 tire has been replaced by "Light duty vehicle, long WB". With this change in methodology, there are substantial differences in activity data among vehicle classes, even though overall VMT and fuel consumption is unchanged. While this is the best data available on

5. *Adjust for fuels consumed for non-energy uses.* U.S. aggregate energy statistics include consumption of fossil fuels for non-energy purposes. These are fossil fuels that are manufactured into plastics, asphalt, lubricants, or other products. 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 (since the C in these fuels ends up in products instead of being combusted), 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 (2012).

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).[79] 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 2011) supplied data on military jet fuel and marine fuel use. Commercial jet fuel use was obtained from FAA (2006, 2009, 2011, and 2012); residual and distillate fuel use for civilian marine bunkers was obtained from DOC (1991 through 2011) for 1990 through 2001 and 2007 through 2010, and DHS (2008) for 2003 through 2006. Consumption of these fuels was subtracted from the corresponding fuels in the transportation end-use sector. Estimates of international bunker fuel emissions for the United States are discussed in detail later in the International Bunker Fuels section of this chapter.

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 2008 (EIA 2009a), and an EPA analysis of C content coefficients used in the mandatory reporting rule (EPA 2010a). A discussion of the methodology used to develop the C content coefficients 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 2012); for each vehicle category, the percent gasoline, diesel, and other (e.g., CNG, LPG) fuel consumption are estimated using data from DOE (1993 through 2011).

    - For non-road vehicles, activity data were obtained from AAR (2009 through 2011), APTA (2007 through 2011), BEA (1991 through 2011), Benson (2002 through 2004), DOE (1993 through 2011), DESC (2011), DOC (1991 through 2011), DOT (1991 through 2011), EIA (2009a), EIA (2011a), EIA (2002), EIA (1991 through 2012), EPA (2011b), and Gaffney (2007).

    - For jet fuel used by aircraft, CO_2 emissions were calculated directly based on reported consumption of

vehicle activity, the time series reflects changes in the definition of vehicle classes between 2006- 2007 when this change in methodology was implemented.

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

fuel as reported by EIA, and allocated to commercial aircraft using flight-specific fuel consumption data from the Federal Aviation Administration's (FAA) Aviation Environmental Design Tool (AEDT) (FAA 2012). [80] Allocation to domestic general aviation was made using FAA Aerospace Forecast data (FAA 2011), and allocation to domestic military uses was made using DoD data (see Annex 3.7).

Heat contents and densities were obtained from EIA (2011a) and USAF (1998). [81]

[BEGIN BOX]

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

Fossil fuels are the dominant source of energy in the United States, and CO_2 is the dominant greenhouse gas emitted as a product from their combustion. Energy-related CO_2 emissions are impacted by not only lower levels of energy consumption 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.[82] 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. 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 3-15 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. 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 3-15: Carbon Intensity from Direct Fossil Fuel Combustion by Sector (Tg CO_2 Eq./QBtu)

Sector	1990		2005	2006	2007	2008	2009	2010
Residential [a]	57.4		56.6	56.5	56.3	56.0	56.0	56.0
Commercial [a]	59.2		57.5	57.2	57.1	56.7	56.9	56.9
Industrial [a]	64.3		64.4	64.5	64.1	63.6	63.0	63.3
Transportation [a]	71.1		71.4	71.6	71.9	71.6	71.5	71.5
Electricity Generation [b]	87.3		85.8	85.4	84.7	84.9	83.7	83.5
U.S. Territories [c]	73.0		73.4	73.5	73.8	73.3	73.1	73.1

[80] Data for inventory years 2000 through 2005 were developed using the FAA's System for assessing Aviation's Global Emissions (SAGE) model. That tool has been incorporated into the Aviation Environmental Design Tool (AEDT), which calculates noise in addition to aircraft fuel burn and emissions for all commercial flights globally in a given year. Data for inventory years 2006-2010 were developed using AEDT. The AEDT model dynamically models aircraft performance in space and time to produce fuel burn, emissions and noise. Full flight gate-to-gate analyses are possible for study sizes ranging from a single flight at an airport to scenarios at the regional, national, and global levels. AEDT is currently used by the U.S. government to consider the interdependencies between aircraft-related fuel burn, noise and emissions. Additional information available at: http://www.faa.gov/about/office_org/headquarters_offices/apl/research/models/

[81] 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.

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

All Sectors [c]	**73.0**	**73.6**	**73.5**	**73.3**	**73.1**	**72.4**	**72.5**

[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.

Over the twenty-one-year period of 1990 through 2010, however, the C intensity of U.S. energy consumption has been fairly constant, as the proportion of fossil fuels used by the individual sectors has not changed significantly. Per capita energy consumption fluctuated little from 1990 to 2007, but in 2010 was approximately 8.0 percent below 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 2011).

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 (2011a), EPA (2010a), and fossil fuel consumption data as discussed above and presented in Annex 2.1.

[END BOX]

Uncertainty and Time Series Consistency

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 . 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.

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 Stochastic 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 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 120 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.[83] 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.[84]

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).[85] 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 3-16. Fossil fuel combustion CO_2 emissions in 2010 were estimated to be between 5,260.8 and 5,638.9 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 2 percent below to 5 percent above the 2010 emission estimate of 5,387.8 Tg CO_2 Eq.

Table 3-16: 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	2010 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		Uncertainty Range Relative to Emission Estimate[a] (%)	
		Lower Bound	Upper Bound	Lower Bound	Upper Bound
Coal [b]	**1,933.2**	**1,868.0**	**2,114.1**	**-3%**	**+9%**
Residential	0.7	0.6	0.8	-6%	+15%
Commercial	5.5	5.2	6.3	-5%	+15%
Industrial	96.2	92.6	112.2	-3%	+17%
Transportation	NE	NE	NE	NA	NA
Electricity Generation	1,827.3	1,756.5	2,001.2	-4%	+10%
U.S. Territories	3.5	3.1	4.2	-12%	+19%

[83] 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.

[84] 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.

[85] 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.

Natural Gas [b]	**1,261.6**	**1,261.9**	**1,332.5**	**+0%**	**+6%**
Residential	258.8	250.0	275.2	-3%	+7%
Commercial	167.7	163.2	179.7	-3%	+7%
Industrial	394.2	374.9	412.7	+3%	+13%
Transportation	40.1	35.2	38.8	-3%	+7%
Electricity Generation	399.4	362.3	392.0	-3%	+5%
U.S. Territories	1.5	1.3	1.7	-12%	+17%
Petroleum [b]	**2,192.6**	**2,032.7**	**2,291.3**	**-7%**	**+5%**
Residential	80.7	76.4	84.9	-5%	5%
Commercial	51.1	48.7	53.2	-5%	4%
Industrial	287.4	235.7	335.0	-18%	17%
Transportation	1,705.4	1,565.6	1,791.4	-8%	5%
Electric Utilities	31.3	29.8	33.7	-5%	8%
U.S. Territories	36.7	33.8	40.9	-8%	12%
Total (excluding Geothermal) [b]	**5,387.4**	**5,260.4**	**5,638.5**	**-2%**	**+5%**
Geothermal	0.4	NE	NE	NE	NE
Total (including Geothermal) [b,c]	**5,387.8**	**5,260.8**	**5,638.9**	**-2%**	**+5%**

NA (Not Applicable)
NE (Not Estimated)
[a] Range of emission estimates predicted by Monte Carlo Stochastic 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.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2010. Details on the emission trends through time are described in more detail in the Methodology section, above.

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 2011a) updated energy consumption statistics across the time series, relative to the previous Inventory. These revisions primarily impacted the emission estimates from 2008 to 2009; however revisions to industrial petroleum consumption impacted estimates across the time series. Overall, these changes resulted in an average annual decrease of 0.2 Tg CO_2 Eq. (less than 0.1 percent) in CO_2 emissions from fossil fuel combustion for the period 1990 through 2009.

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 elicitation may be conducted to better quantify the total uncertainty associated with emissions from this source.

The availability of facility-level combustion emissions through EPA's Greenhouse Gas Reporting Program (GHGRP) will be examined to help better characterize the industrial sector's energy consumption in the United States, and further classify business establishments according to industrial economic activity type. Most methodologies used in EPA's GHGRP are consistent with IPCC, though for EPA's GHGRP, facilities collect

detailed information specific to their operations according to detailed measurement standards, which may differ with the more aggregated data collected for the Inventory to estimate total, national U.S. emissions. In addition, and unlike the reporting requirements for this chapter under the UNFCCC reporting guidelines,[86] some facility-level fuel combustion emissions reported under the GHGRP may also include industrial process emissions. In line with UNFCCC reporting guidelines, fuel combustion emissions are included in this chapter, while process emissions are included in the Industrial Processes chapter of this report. In examining data from EPA's GHGRP that would be useful to improve the emission estimates for the CO_2 from fossil fuel combustion category, particular attention will also be made to ensure time series consistency, as the facility-level reporting data from EPA's GHGRP are not available for all inventory years as reported in this inventory. Additionally, analyses will focus on aligning reported facility-level fuel types and IPCC fuel types per the national energy statistics, ensuring CO_2 emissions from biomass are separated in the facility-level reported data, and maintaining consistency with national energy statistics provided by EIA. In implementing improvements and integration of data from EPA's GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will be relied upon.[87]

CH_4 and N_2O from Stationary Combustion

Methodology

Methane and N_2O emissions from stationary combustion were estimated by multiplying fossil fuel and wood consumption data by emission factors (by sector and fuel type for industrial, residential, commercial, and U.S. Territories; and by fuel and technology type for the electric power sector). Beginning with this year's Inventory, the electric power sector utilizes a Tier 2 methodology, whereas all other sectors utilize a Tier 1 methodology. The activity data and emission factors used are described in the following subsections.

Industrial, Residential, Commercial, and U.S. Territories

National coal, natural gas, fuel oil, and wood consumption data were grouped by sector: industrial, commercial, residential, and U.S. territories. For the CH_4 and N_2O estimates, wood consumption data for the United States was obtained from EIA's Annual Energy Review (EIA 2011a). Fuel consumption data for coal, natural gas, and fuel oil for the United States were obtained from EIA's Monthly Energy Review and unpublished supplemental tables on petroleum product detail (EIA 2011b). Because the United States does not include territories in its national energy statistics, fuel consumption data for territories were provided separately by Jacobs (2010).[88] Fuel consumption for the industrial sector was adjusted to subtract out construction and agricultural use, which is reported under mobile sources.[89] Construction and agricultural fuel use was obtained from EPA (2010a). 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. Tier 1 default emission factors for these three 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.

Electric Power Sector

In this year's Inventory, the emission estimation methodology for the electric power sector was revised from Tier 1 to Tier 2 as fuel consumption for the electricity generation sector by control-technology type was obtained from EPA's Acid Rain Program Dataset (EPA 2011). This combustion technology- and fuel-use data was available by facility from 1996 to 2010.

Since there was a difference between the EPA (2011) and EIA (2011a) total energy consumption estimates, the

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[86] See <http://unfccc.int/resource/docs/2006/sbsta/eng/09.pdf>

[87] See <http://www.ipcc-nggip.iges.or.jp/meeting/pdfiles/1008_Model_and_Facility_Level_Data_Report.pdf>

[88] 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.

[89] 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.

remainder between total energy consumption using EPA (2011) and EIA (2011a) was apportioned to each combustion technology type and fuel combination using a ratio of energy consumption by technology type from 1996 to 2010.

Energy consumption estimates were not available from 1990 to 1995 in the EPA (2011) dataset, and as a result, consumption was calculated using total electric power consumption from EIA (2011a) and the ratio of combustion technology and fuel types from EPA (2011). The consumption estimates from 1990 to 1995 were estimated by applying the 1996 consumption ratio by combustion technology type to the total EIA consumption for each year from 1990 to 1995. Emissions were estimated by multiplying fossil fuel and wood consumption by technology- and fuel-specific Tier 2 IPCC emission factors.

Lastly, there were significant differences between wood biomass consumption in the electric power sector between the EPA (2011) and EIA (2011a) datasets. The difference in wood biomass consumption in the electric power sector was distributed to the residential, commercial, and industrial sectors according to their percent share of wood biomass energy consumption calculated from EIA (2011a).

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 and Time-Series Consistency

Methane 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 Stochastic 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. About 55 input variables were simulated for the uncertainty analysis of this source category (about 20 from the CO_2 emissions from fossil fuel combustion inventory estimation model and about 35 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.[90] For these variables, the uncertainty ranges were assigned to the input variables based on the data reported in SAIC/EIA (2001).[91] 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 3-17. Stationary combustion CH_4 emissions in 2010 (including biomass) were estimated to be between 3.8 and 14.4 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 40 percent below to 128 percent above the 2010 emission estimate of 6.3 Tg CO_2 Eq.[92] Stationary combustion N_2O emissions in 2010 (*including* biomass) were estimated to be between 9.9 and 38.8 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 56 percent below to 72 percent above the 2010 emissions estimate of 22.6 Tg CO_2 Eq.

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[90] 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.

[91] 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.

[92] 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.

Table 3-17: 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)

Source	Gas	2010 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
Stationary Combustion	CH_4	6.3	3.8	14.4	-40%	+128%
Stationary Combustion	N_2O	22.6	9.9	38.8	-56%	+72%

[a] Range of emission estimates predicted by Monte Carlo Stochastic 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.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2010. Details on the emission trends through time are described in more detail in the Methodology section, above.

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 a few of changes, impacting the entire time series, relative to the previous Inventory. Slight changes to emission estimates for sectors are due to revised data from EIA (2011). Wood consumption data in EIA (2011) were revised for the residential, commercial, electric power, and industrial sectors from 1990 to 2009. Additionally, a Tier 2 emission estimation methodology was applied to estimate emissions from the electric power sector across the entire time series. This primarily impacted N_2O emission estimates, as the number of coal fluidized bed boilers increased significantly from 2000 through 2005. The combination of the methodological and historical data changes resulted in an average annual increase of less than 0.1 Tg CO_2 Eq. (0.5 percent) in CH_4 emissions from stationary combustion and an average annual increase of 1.9 Tg CO_2 Eq. (13.7 percent) in N_2O emissions from stationary combustion for the period 1990 through 2009.

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.

Beginning in 2010, those facilities that emit over 25,000 tons of greenhouse gases (CO_2 Eq.) from stationary combustion across all sectors of the economy are required to calculate and report their greenhouse gas emissions to EPA through its GHGRP. These data will be used in future inventories to improve the emission calculations through

the use of these collected higher tier methodological data.

Future improvements to the CH_4 and N_2O from Stationary Combustion category involve research into the availability of CH_4 and N_2O from stationary combustion data, and analyzing data reported under EPA's GHGRP. In examining data from EPA's GHGRP that would be useful to improve the emission estimates for CH_4 and N_2O from Stationary Combustion category, particular attention will be made to ensure time series consistency, as the facility-level reporting data from EPA's GHGRP are not available for all Inventory years as reported in this inventory. In implementing improvements and integration of data from EPA's GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will be relied upon. [93]

CH_4 and N_2O from Mobile Combustion

Methodology

Estimates of CH_4 and N_2O 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_2O emissions from mobile combustion and the emission factors used in the calculations is provided in Annex 3.2.

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)[94] 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 greenhouse gases 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, NO_x, and PM from vehicles under various conditions, to approximate average driving characteristics.[95]

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 2010 were obtained from the Federal Highway Administration's (FHWA) Highway Performance Monitoring System database as reported in Highway Statistics (FHWA 1996 through

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[93] See <http://www.ipcc-nggip.iges.or.jp/meeting/pdfiles/1008_Model_and_Facility_Level_Data_Report.pdf>

[94] 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 bi-fuel or dual-fuel vehicles that may be partially powered by gasoline or diesel.

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

2012).[96] 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 2011) and information on total motor vehicle fuel consumption by fuel type from FHWA (1996 through 2012). VMT for AFVs were taken from Browning (2003). The age distributions of the U.S. vehicle fleet were obtained from EPA (2011a, 2000), and the average annual age-specific vehicle mileage accumulation of U.S. vehicles were obtained 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).

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).[97] Activity data were obtained from AAR (2009 through 2011), APTA (2007 through 2011), APTA (2006), BEA (1991 through 2005), Benson (2002 through 2004), DHS (2008), DOC (1991 through 2011), DOE (1993 through 2011), DESC (2011), DOT (1991 through 2011), EIA (2008a, 2011, 2012 2002), EIA (2007 through 2011), EIA (1991 through 2012), EPA (2009), Esser (2003 through 2004), FAA (2012, 2011, and 2006), and Gaffney (2007). Emission factors for non-road modes were taken from IPCC/UNEP/OECD/IEA (1997) and Browning (2009).

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis was conducted for the mobile source sector using the IPCC-recommended Tier 2 uncertainty estimation methodology, Monte Carlo Stochastic Simulation technique, using @RISK software. The uncertainty analysis was performed on 2010 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 four major sets of input variables: (1) vehicle miles traveled (VMT) data, by on-road vehicle and fuel type and (2) emission factor data, by on-road vehicle, fuel, and control technology type, (3) fuel consumption, data, by non-road vehicle and equipment type, and (4) emission factor data, by non-road vehicle and equipment 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.

Mobile combustion CH_4 emissions from all mobile sources in 2010 were estimated to be between 1.7 and 2.1 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 10 percent below to 9 percent above the corresponding 2010 emission estimate of 1.9 Tg CO_2 Eq. Also at a 95 percent confidence level, mobile combustion N_2O emissions from mobile sources in 2010 were estimated to be between 19.3 and 25.9 Tg CO_2 Eq., indicating a range of 6 percent below to 26 percent above the corresponding 2010 emission estimate of 20.6 Tg CO_2 Eq.

Table 3-18: 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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[96] The source of VMT and fuel consumption is FHWA's VM-1 table. The data collection methodology has undergone substantial revision for only years 2007-2010, while prior years have remain unchanged Several of the vehicle type categories have changed. For instance, passenger car has been replaced by "Light duty vehicle, short WB" and other 4 axle- 2 tire has been replaced by "Light duty vehicle, long WB". With this change in methodology, there are substantial differences in activity data among vehicle classes, even though overall VMT and fuel consumption is unchanged. While this is the best data available on vehicle activity, the time series reflects changes in the definition of vehicle classes between 2006- 2007 when this change in methodology was implemented.

[97] 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	2010 Emission Estimate[a] (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Mobile Sources	CH_4	1.9	1.7	2.1	-10%	+9%
Mobile Sources	N_2O	20.6	19.3	25.9	-6%	+26%

[a] Range of emission estimates predicted by Monte Carlo Stochastic 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_2O please refer to the Uncertainty Annex.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

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. Each year, adjustments are made to the methodologies used in calculating emissions in the current Inventory relative to previous Inventory reports.

In 2011, FHWA revised the methodology of their VM-1 table, which provides the source data for on-road vehicle VMT, fuel consumption, and miles per gallon. FHWA's data collection methodology has undergone substantial revision for only years 2007 to 2010, while prior years have remained unchanged. With this revision, several of the vehicle type categories have changed. For instance, passenger car has been replaced by "Light duty vehicle, short wheel-base" and other 4 axle- 2 tire has been replaced by "Light duty vehicle, long wheel-base". With this change in methodology, there are substantial differences in activity data among vehicle classes, even though overall VMT and fuel consumption is unchanged. While this is the best data available on vehicle activity, the time series reflects changes in the definition of vehicle classes between 2006- 2007, when this change in methodology was implemented.

The underlying data used for calculating Alternative Fuel Vehicles VMT has changed substantially. This data is supplied by the U.S. Energy Information Administration, Office of Energy Consumption and Efficiency Statistics, and the DOE/GSA Federal Automotive Statistical Tool (FAST). EIA changed its reporting methodology for 2005-2010, and has provided more detail on alternative fuel vehicle use by vehicle class. The fuel use breakdown by vehicle class had previously been based on estimates of the distribution of fuel use by vehicle class, while the new data from EIA allowed actual data to be used for fuel use, and resulted in greater share of heavy-duty AFV VMT estimated for 2005-2010.

As a result of these changes, estimates of CH_4 emissions were slightly higher than previous Inventory years, while N_2O emissions were slightly higher for 2005 and 2006 and lower for 2007 through 2009. CH_4 emissions for 2006 increased the most, 2 percent (less than 0.1 Tg CO_2 Eq.). N_2O emissions for 2009 decreased 6 percent (1.4 Tg CO_2 Eq.), the greatest decrease relative to the previous inventory.

Planned Improvements

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

1. Develop updated emissions factors for diesel vehicles, motorcycle, and biodiesel vehicles. Previous emission factors were based upon extrapolations from other vehicle classes and new test data from Environment Canada and other sources may allow for better estimation of emission factors for these vehicles.
2. Develop new emission factors for non-road equipment. The current inventory estimates for non-CO_2 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.
3. Examine the feasibility of estimating aircraft N_2O and CH_4 emissions by the number of takeoffs and landings, instead of total fuel consumption. Various studies have indicated that aircraft N_2O and CH_4 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 and AEDT databases contain detailed data on takeoffs and landings for each calendar year starting in 2000, 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, the development of procedures to develop comparable estimates for years prior to 2000, and the dynamic interaction of ambient air with aircraft exhausts is developed. The feasibility of this approach will be explored.
4. Develop improved estimates of domestic waterborne fuel consumption. The inventory estimates for residual and distillate fuel used by ships and boats is based in part on data on bunker fuel use from the U.S. Department of Commerce. Domestic fuel consumption is estimated by subtracting fuel sold for international use from the total sold in the United States. It may be possible to more accurately estimate domestic fuel use and emissions by using detailed data on marine ship activity. The feasibility of using domestic marine activity data to improve the estimates will be investigated.
5. 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.

3.2. 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 (metallurgical) coke (manufactured from coking coal). The non-energy applications of these fuels are equally diverse, including 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 Incineration of Waste 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 the inventory calculations make adjustments to address the effect of net exports on the mass of C in non-energy applications.

As shown in Table 3-19, fossil fuel emissions in 2010 from the non-energy uses of fossil fuels were 125.1 Tg CO_2 Eq., which constituted approximately 2 percent of overall fossil fuel emissions. In 2010, the consumption of fuels for non-energy uses (after the adjustments described above) was 4,651.0 TBtu, an increase of 4.3 percent since 1990 (see Table 3-20). About 52.3 Tg of the C (191.7 Tg CO_2 Eq.) in these fuels was stored, while the remaining 34.1 Tg C (125.1 Tg CO_2 Eq.) was emitted.

Table 3-19: CO_2 Emissions from Non-Energy Use Fossil Fuel Consumption (Tg CO_2 Eq.)

Year	1990		2005	2006	2007	2008	2009	2010
Potential Emissions	310.9		387.2	381.6	367.0	341.7	310.6	316.9
C Stored	191.3		243.1	237.8	232.1	203.1	186.9	191.7
Emissions as a % of Potential	38%		37%	38%	37%	41%	40%	39%
Emissions	**119.6**		**144.1**	**143.8**	**134.9**	**138.6**	**123.7**	**125.1**

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 (2011) (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 3-20 and Table 3-21 have been adjusted to subtract non-energy uses that are included in the source categories of the Industrial Processes chapter.[98] Consumption values were also adjusted to subtract net 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 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 Incineration of Waste 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 3-20: Adjusted Consumption of Fossil Fuels for Non-Energy Uses (TBtu)

Year	1990		2005	2006	2007	2008	2009	2010
Industry	**4,197.8**		**5,309.5**	**5,181.3**	**5,012.3**	**4,626.9**	**4,335.1**	**4,453.5**

[98] 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.

Industrial Coking Coal	+	80.5	62.9	2.3	29.2	6.4	64.9
Industrial Other Coal	8.2	11.9	11.9	11.9	11.9	11.9	10.3
Natural Gas to Chemical Plants	263.7	390.1	228.3	223.0	227.3	220.5	222.8
Asphalt & Road Oil	1,170.2	1,323.2	1,261.2	1,197.0	1,012.0	873.1	877.8
LPG	1,168.7	1,667.9	1,754.8	1,703.3	1,609.2	1,702.6	1,817.3
Lubricants	186.3	160.2	156.1	161.2	149.6	134.5	149.5
Pentanes Plus	84.9	105.2	74.3	91.6	64.9	70.1	67.8
Naphtha (<401 ° F)	326.2	680.5	618.3	542.5	467.2	451.3	472.7
Other Oil (>401 ° F)	662.1	500.4	573.6	669.1	599.1	393.0	404.9
Still Gas	21.3	67.7	57.2	44.2	47.3	133.9	147.2
Petroleum Coke	27.2	105.2	134.2	117.8	147.4	112.1	1.1
Special Naphtha	100.9	61.0	68.9	75.4	83.2	44.3	25.6
Distillate Fuel Oil	7.0	11.7	17.5	17.5	17.5	17.5	17.5
Waxes	33.3	31.4	26.1	21.9	19.1	12.2	15.4
Miscellaneous Products	137.8	112.8	136.0	133.5	142.0	151.8	158.8
Transportation	**176.0**	**151.3**	**147.4**	**152.2**	**141.3**	**127.1**	**141.2**
Lubricants	176.0	151.3	147.4	152.2	141.3	127.1	141.2
U.S. Territories	**86.7**	**121.9**	**133.4**	**108.4**	**126.7**	**56.3**	**56.3**
Lubricants	0.7	4.6	6.2	5.9	2.7	1.0	1.0
Other Petroleum (Misc. Prod.)	86.0	117.3	127.2	102.5	124.1	55.2	55.2
Total	**4,460.5**	**5,582.8**	**5,462.1**	**5,272.9**	**4,895.0**	**4,518.4**	**4,651.0**

Table 3-21: 2010 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	**4,453.5**	**-**	**82.4**	**-**	**51.9**	**30.5**	**111.9**
Industrial Coking Coal	64.9	25.61	1.7	0.10	0.2	1.5	5.5
Industrial Other Coal	10.3	25.82	0.3	0.59	0.2	0.1	0.4
Natural Gas to Chemical Plants	222.8	14.47	3.2	0.59	1.9	1.3	4.8
Asphalt & Road Oil	877.8	20.55	18.0	1.00	18.0	0.1	0.3
LPG	1,817.3	17.06	31.0	0.59	18.4	12.6	46.1
Lubricants	149.5	20.20	3.0	0.09	0.3	2.7	10.1
Pentanes Plus	67.8	19.10	1.3	0.59	0.8	0.5	1.9
Naphtha (<401° F)	472.7	18.55	8.8	0.59	5.2	3.6	13.1
Other Oil (>401° F)	404.9	20.17	8.2	0.59	4.9	3.3	12.2
Still Gas	147.2	17.51	2.6	0.59	1.5	1.0	3.8
Petroleum Coke	1.1	27.85	+	0.30	+	+	0.1
Special Naphtha	25.6	19.74	0.5	0.59	0.3	0.2	0.8
Distillate Fuel Oil	17.5	20.17	0.4	0.50	0.2	0.2	0.6
Waxes	15.4	19.80	0.3	0.58	0.2	0.1	0.5
Miscellaneous Products	158.8	20.31	3.2	+	+	3.2	11.8
Transportation	**141.2**	**-**	**2.9**	**-**	**0.3**	**2.6**	**9.5**
Lubricants	141.2	20.20	2.9	0.09	0.3	2.6	9.5
U.S. Territories	**56.3**	**-**	**1.1**	**-**	**0.1**	**1.0**	**3.7**
Lubricants	1.0	20.20	+	0.09	+	+	0.1
Other Petroleum (Misc. Prod.)	55.2	20.00	1.1	0.10	0.1	1.0	3.6
Total	**4,651.0**		**86.4**		**52.3**	**34.1**	**125.1**

+ Does not exceed 0.05 Tg
- Not applicable.
[a] To avoid double counting, net 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 3-19). 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 energy recovery, Toxics Release Inventory (TRI) releases, hazardous waste incineration, and volatile organic compound, solvent, and non-combustion CO emissions. 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 2001), *National Emissions Inventory (NEI) Air Pollutant Emissions Trends Data* (EPA 2010), *Toxics Release Inventory, 1998* (2000b), *Biennial Reporting System* (EPA 2004, 2009), and pesticide sales and use estimates (EPA 1998, 1999, 2002, 2004, 2011); the EIA Manufacturer's Energy Consumption Survey (MECS) (EIA 1994, 1997, 2001, 2005, 2010); the National Petrochemical & Refiners Association (NPRA 2002); the U.S. Bureau of the Census (1999, 2004, 2009); Bank of Canada (2011); Financial Planning Association (2006); INEGI (2006); the United States International Trade Commission (2011); Gosselin, Smith, and Hodge (1984); the Rubber Manufacturers' Association (RMA 2009a,b); the International Institute of Synthetic Rubber Products (IISRP 2000, 2003); the Fiber Economics Bureau (FEB 2011); and the American Chemistry Council (ACC 2003-2010, 2011). Specific data sources are listed in full detail in Annex 2.3.

Uncertainty and Time-Series Consistency

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 Stochastic 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 in Table 3-20 and Table 3-21), 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 3-22 (emissions) and Table 3-23 (storage factors). Carbon emitted from non-energy uses of fossil fuels in 2010 was estimated to be between 103.8 and 154.0 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 17 percent below to 23 percent above the 2010 emission estimate of 125.1 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 3-22: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Non-Energy Uses of Fossil Fuels (Tg CO_2 Eq. and Percent)

Source	Gas	2010 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	83.1	65.2	114.0	-22%	37%
Asphalt	CO_2	0.3	0.1	0.6	-58%	117%
Lubricants	CO_2	19.6	16.2	22.8	-18%	16%
Waxes	CO_2	0.5	0.3	0.8	-28%	63%
Other	CO_2	21.7	13.9	24.5	-36%	13%
Total	**CO_2**	**125.1**	**103.8**	**154.0**	**-17%**	**23%**

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

Table 3-23: Tier 2 Quantitative Uncertainty Estimates for Storage Factors of Non-Energy Uses of Fossil Fuels (Percent)

Source	Gas	2010 Storage Factor (%)	Uncertainty Range Relative to Emission Estimate[a] (%)		(%, Relative)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Feedstocks	CO_2	59%	54%	61%	-10%	3%
Asphalt	CO_2	99.6%	99%	100%	-1%	0%
Lubricants	CO_2	9%	4%	17%	-59%	90%
Waxes	CO_2	58%	49%	71%	-15%	23%
Other	CO_2	16%	10%	44%	-39%	179%

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

In Table 3-23, 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.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2010. Details on the emission trends through time are described in more detail in the Methodology section, above.

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 2011 as well as their trends across the time series.

Petrochemical input data reported by EIA will continue to be investigated in an attempt to address an input/output discrepancy in the NEU model. Since 2001, the C accounted for in the feedstocks C balance outputs (i.e., storage plus emissions) exceeds C inputs. Prior to 2001, the C balance inputs exceed outputs. EPA has reduced a portion of this discrepancy (see Recalculations Discussion below) and has developed two strategies to address the remaining portion (see Planned Improvements below).

Recalculations Discussion

Relative to the previous Inventory, emissions from non-energy uses of fossil fuels decreased by an average of 1.2 Tg CO_2 Eq. (0.7 percent) across the entire time series. Two competing changes contributed to these recalculations. The

larger of the two changes was a decrease in emissions caused by a change in petrochemical input data reported by the Energy Information Administration in its Monthly Energy Review. In particular, a decline in EIA's estimate of petroleum coke consumed for non-energy purposes across the time series explains the majority of the decrease. The smaller of the two changes was an increase in emissions caused by EIA's revision of its methodology for calculating LPG consumed for non-energy uses in consultation with EPA. These estimates had previously been based on the assumption that the portion of LPG used for NEU remained constant at its 2004 level for the rest of the time series. For this year's Inventory, EIA instead retrieved data describing the portion of LPG in NEU from Petroleum Supply Annual for the entire 1990-2010 time series and revised the previous assumption accordingly. Because 2004 was an uncharacteristically low year for non-energy consumption of LPG, this revision resulted in an overall increase in estimates of LPG consumed for NEU and thus an increase in estimated emissions. Combined, the net effect of these two changes was to decrease emission estimates across the time series slightly.

The revision to LPG calculations mentioned above also significantly reduced the input/output discrepancy in the NEU model. Specifically, this discrepancy was reduced by an average of 43% between 2000 and 2010, the years in which the discrepancy had previously been the largest.

Planned Improvements

There are several improvements planned for the future:

- More accurate accounting of C in petrochemical feedstocks. EPA has worked with EIA to determine the cause of an input/output discrepancy in the carbon mass balance contained within the NEU model. In the future, EPA will continue to pursue two strategies to reduce or eliminate this discrepancy. First, EPA will improve its accounting of C in imports and exports. EPA will examine its import/export adjustment methodology to ensure that net exports of intermediaries such as ethylene and propylene are fully accounted for. Second, EPA will reconsider its use of top-down C input calculation in estimating emissions. It will consider alternative approaches that rely more substantially on the bottom-up C output calculation instead.
- 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).
- Reviewing the trends in fossil fuel consumption for non-energy uses. Annual consumption for several fuel types is highly variable across the time series, including industrial coking coal and other petroleum (miscellaneous products). EPA plans to better understand these trends to identify any mischaracterized or misreported fuel consumption for non-energy uses.
- EPA recently researched updating the average carbon content of solvents, since the entire time series depends on one year's worth of solvent composition data. Unfortunately, the data on C emissions from solvents that were readily available do not provide composition data for all categories of solvent emissions and also have conflicting definitions for volatile organic compounds, the source of emissive carbon in solvents. EPA plans to identify additional sources of solvents data in order to update the C content assumptions.

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 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 or deferring to more updated default storage factors from IPCC where available.

Finally improvements to this category will involve analysis of the data reported under EPA's GHGRP. In examining data from EPA's GHGRP that would be useful to improve the emission estimates for the carbon emitted from non-energy uses of fossil fuels category, particular attention will be made to ensure time series consistency, as the facility-level reporting data from EPA's GHGRP are not available for all Inventory years as reported in this inventory. In implementing improvements and integration of data from EPA's GHGRP, the latest guidance from the

IPCC on the use of facility-level data in national inventories will be relied upon.[99]

3.3. Incineration of Waste (IPCC Source Category 1A1a)

Incineration is used to manage about 7 to 19 percent of the solid wastes 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 2000, Goldstein and Matdes 2001, Kaufman et al. 2004, Simmons et al. 2006, van Haaren et al. 2010). In the context of this section, waste includes all municipal solid waste (MSW) as well as tires. In the United States, almost all incineration of MSW occurs at waste-to-energy facilities or industrial facilities where useful energy is recovered, and thus emissions from waste incineration are accounted for in the Energy chapter. Similarly, tires are combusted for energy recovery in industrial and utility boilers. Incineration of waste 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 incineration 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. As noted above, tires (which contain rubber and carbon black) are also considered a "non-hazardous" waste and are included in the waste incineration estimate, though waste disposal practices for tires differ from municipal solid waste. Estimates on emissions from hazardous waste incineration can be found in Annex 2.3 and are accounted for as part of the C mass balance for non-energy uses of fossil fuels.

Approximately 26.5 million metric tons of MSW was incinerated in the United States in 2010 (EPA 2011a). CO_2 emissions from incineration of waste rose 51 percent since 1990, to an estimated 12.1 Tg CO_2 Eq. (12,054 Gg) in 2010, as the volume of tires and other fossil C-containing materials in waste increased (see Table 3-24 and Table 3-25). Waste incineration is also a source of N_2O and CH_4 emissions (De Soete 1993; IPCC 2006). N_2O emissions from the incineration of waste were estimated to be 0.4 Tg CO_2 Eq. (1 Gg N_2O) in 2010, and have not changed significantly since 1990. CH_4 emissions from the incineration of waste were estimated to be less than 0.05 Tg CO_2 Eq. (less than 0.5 Gg CH_4) in 2010, and have not changed significantly since 1990.

Table 3-24: CO_2 and N_2O Emissions from the Incineration of Waste (Tg CO_2 Eq.)

Gas/Waste Product	1990	2005	2006	2007	2008	2009	2010
CO_2	**8.0**	**12.5**	**12.5**	**12.7**	**11.9**	**11.7**	**12.1**
Plastics	5.6	6.9	6.7	6.7	6.1	6.2	6.6
Synthetic Rubber in Tires	0.3	1.6	1.7	1.8	1.7	1.6	1.6
Carbon Black in Tires	0.4	2.0	2.1	2.3	2.1	1.9	1.9
Synthetic Rubber in MSW	0.9	0.8	0.8	0.8	0.8	0.8	0.8
Synthetic Fibers	0.8	1.2	1.2	1.2	1.2	1.2	1.2
N_2O	**0.5**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**
CH_4	+	+	+	+	+	+	+
Total	**8.5**	**12.9**	**12.9**	**13.1**	**12.3**	**12.1**	**12.4**

+ Does not exceed 0.05 Tg CO_2 Eq.

Table 3-25: CO_2 and N_2O Emissions from the Incineration of Waste (Gg)

Gas/Waste Product	1990	2005	2006	2007	2008	2009	2010
CO_2	**7,989**	**12,468**	**12,531**	**12,727**	**11,888**	**11,703**	**12,054**
Plastics	5,588	6,919	6,722	6,660	6,148	6,233	6,573

[99] See <http://www.ipcc-nggip.iges.or.jp/meeting/pdfiles/1008_Model_and_Facility_Level_Data_Report.pdf>

Synthetic Rubber in Tires	308		1,599	1,712	1,823	1,693	1,560	1,560
Carbon Black in Tires	385		1,958	2,113	2,268	2,085	1,903	1,903
Synthetic Rubber in MSW	872		781	775	791	770	782	787
Synthetic Fibers	838		1,211	1,208	1,185	1,192	1,226	1,230
N_2O	**2**		**1**	**1**	**1**	**1**	**1**	**1**
CH_4	+		+	+	+	+	+	+

+ Does not exceed 0.5 Gg.

Methodology

Emissions of CO_2 from the incineration of waste include CO_2 generated by the incineration of plastics, synthetic fibers, and synthetic rubber, as well as the incineration of synthetic rubber and carbon black in tires. These emissions were estimated by multiplying the amount of each material incinerated by the C content of the material and the fraction oxidized (98 percent). Plastics incinerated 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 amount of scrap tires used for fuel and the synthetic rubber and carbon black content of tires.

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

For each of the methods used to calculate CO_2 emissions from the incineration of waste, 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 specific materials discarded as municipal solid waste (i.e., the quantity generated minus the quantity recycled) was taken from *Municipal Solid Waste Generation, Recycling, and Disposal in the United States: Facts and Figures* (EPA 2000 through 2003, 2005 through 2011b) and detailed unpublished backup data for some years not shown in the reports (Schneider 2007). The proportion of total waste discarded that is incinerated was derived from data in BioCycle's "State of Garbage in America" (van Haaren et al. 2010). The most recent data provides the proportion of waste incinerated for 2008, so the corresponding proportion in 2010 is assumed to be equal to the proportion in 2008. For synthetic rubber and carbon black in scrap tires, information was obtained from U.S. Scrap Tire Management Summary for 2005 through 2009 data (RMA 2011). For 2010, synthetic rubber mass in tires is assumed to be equal to that in 2009 due to a lack of more recently available data.

Average C contents for the "Other" plastics category and synthetic rubber in municipal solid wastes were calculated from 1998 and 2002 production statistics: carbon content for 1990 through 1998 is based on the 1998 value; content for 1999 through 2001 is the average of 1998 and 2002 values; and content for 2002 to date is based on the 2002 value. Carbon content for synthetic fibers was calculated from 1999 production statistics. Information about scrap tire composition was taken from the Rubber Manufacturers' Association internet site (RMA 2012a).

The assumption that 98 percent of organic C is oxidized (which applies to all waste incineration 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 2006).

Incineration of waste, including MSW, also results in emissions of N_2O and CH_4. These emissions were calculated as a function of the total estimated mass of waste incinerated and an emission factor. As noted above, N_2O and CH_4 emissions are a function of total waste incinerated in each year; for 1990 through 2008, these data were derived from the information published in BioCycle (van Haaren et al. 2010). Data on total waste incinerated was not available for 2009 or 2010, so this value was assumed to equal the most recent value available (2008).

Table 3-26 provides data on municipal solid waste discarded and percentage combusted for the total waste stream. According to Covanta Energy (Bahor 2009) and confirmed by additional research based on ISWA (ERC 2009), all municipal solid waste combustors in the United States are continuously fed stoker units. The emission factors of N_2O and CH_4 emissions per quantity of municipal solid waste combusted are default emission factors for this technology type and were taken from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006).

Table 3-26: Municipal Solid Waste Generation (Metric Tons) and Percent Combusted.

Year	Waste Discarded	Waste Incinerated	Incinerated (% of Discards)
1990	235,733,657	30,632,057	13.0
2005	259,559,787	25,973,520	10.0
2006	267,526,493	25,853,401	9.7
2007	268,279,240	24,788,539	9.2
2008	268,541,088	23,674,017	8.8
2009	268,541,088[a]	23,674,017[a]	8.8[a]
2010	268,541,088[a]	23,674,017[a]	8.8[a]

[a] Assumed equal to 2008 value.
Source: van Haaren et al. (2010).

Uncertainty and Time-Series Consistency

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 the incineration of waste (given the very low emissions for CH_4, no uncertainty estimate was derived). 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 incineration emission estimates arise from both the assumptions applied to the data and from the quality of the data. Key factors include MSW incineration rate; fraction oxidized; missing data on waste composition; average C content of waste 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 3-27. Waste incineration CO_2 emissions in 2010 were estimated to be between 9.6and 14.9 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 21 percent below to 24 percent above the 2010 emission estimate of 12.1 Tg CO_2 Eq. Also at a 95 percent confidence level, waste incineration N_2O emissions in 2010 were estimated to be between 0.2 and 1.5 Tg CO_2 Eq. This indicates a range of 50 percent below to 320 percent above the 2010 emission estimate of 0.4 Tg CO_2 Eq.

Table 3-27: Tier 2 Quantitative Uncertainty Estimates for CO_2 and N_2O from the Incineration of Waste (Tg CO_2 Eq. and Percent)

Source	Gas	2010 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
Incineration of Waste	CO_2	12.1	9.6	14.9	-21%	+24%
Incineration of Waste	N_2O	0.4	0.2	1.5	-50%	+320%

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

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990

through 2010. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific QA/QC plan was implemented for incineration of waste. 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 incineration of waste. Trends across the time series were analyzed to determine whether any corrective actions were needed. Actions were taken to streamline the activity data throughout the calculations on incineration of waste.

Recalculations Discussion

Several changes were made to input variables compared to the previous Inventory, resulting in an overall decrease in the total emissions from the incineration of waste. The emissions from carbon black and rubber in scrap tires in 2008 and 2009 were updated based on data obtained from the Rubber Manufacturers' Association U.S. Scrap Tire Management Summary for 2005 through 2009 (RMA 2012b), because the report releases data every other year. The 2009 data was available in this report, so 2008 data was updated using linear interpolation from the 2007 and 2009 data. The change decreased the 2008 and 2009 emissions by 2 percent and 5 percent, respectively, relative to the previous report.

Planned Improvements

The availability of facility-level waste incineration through EPA's GHGRP will be examined to help better characterize waste incineration operations in the United States. This characterization could include future improvements as to the operations involved in waste incineration for energy, whether in the power generation sector or the industrial sector. Additional examinations will be necessary as, unlike the reporting requirements for this chapter under the UNFCCC reporting guidelines,[100] some facility-level waste incineration emissions reported under the GHGRP may also include industrial process emissions. In line with UNFCCC reporting guidelines, emissions for waste incineration with energy recovery are included in this chapter, while process emissions are included in the industrial processes chapter of this report. In examining data from EPA's GHGRP that would be useful to improve the emission estimates for the waste incineration category, particular attention will also be made to ensure time series consistency, as the facility-level reporting data from EPA's GHGRP are not available for all inventory years as reported in this inventory. Additionally, analyses will focus on ensuring CO_2 emissions from the biomass component of waste are separated in the facility-level reported data, and on maintaining consistency with national waste generation and fate statistics currently used to estimate total, national U.S. greenhouse gase emissions. In implementing improvements and integration of data from EPA's GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will be relied upon.[101]

3.4. 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. In 2010, 164 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, 24 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 2010, 15 coal mines collected CH_4 from degasification systems and utilized this gas, thus reducing emissions to the atmosphere. Of these mines, 14 coal mines sold CH_4 to the natural gas pipeline and one coal mine used CH_4 from its degasification system to heat mine

[100] See <http://unfccc.int/resource/docs/2006/sbsta/eng/09.pdf>

[101] See <http://www.ipcc-nggip.iges.or.jp/meeting/pdfiles/1008_Model_and_Facility_Level_Data_Report.pdf>

ventilation air on site. In addition, one of the coal mines that sold gas to pipelines also used CH_4 to 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 2010 were estimated to be 72.6 Tg CO_2 Eq. (3,458 Gg), a decline of 14 percent since 1990 (see Table 3-28 and Table 3-29). Of this amount, underground mines accounted for 71 percent, surface mines accounted for 18 percent, and post-mining emissions accounted for 11 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 CH_4 emissions have remained fairly level, while surface coal production and its associated emissions have generally increased.

Table 3-28: CH_4 Emissions from Coal Mining (Tg CO_2 Eq.)

Activity	1990		2005	2006	2007	2008	2009	2010
UG Mining	62.3		34.9	34.9	35.7	44.9	49.6	51.6
Liberated	67.9		50.2	50.2	50.9	60.5	66.1	71.4
Recovered & Used	(5.6)		(15.2)	(18.8)	(15.2)	(16.3)	(16.6)	(19.6)
Surface Mining	12.0		13.3	14.0	13.8	14.3	12.9	13.1
Post-Mining (UG)	7.7		6.4	6.3	6.1	6.1	5.6	5.7
Post-Mining (Surface)	2.0		2.2	2.3	2.2	2.3	2.1	2.1
Total	**84.1**		**56.8**	**56.8**	**57.8**	**66.9**	**70.1**	**72.6**

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

Table 3-29: CH_4 Emissions from Coal Mining (Gg)

Activity	1990		2005	2006	2007	2008	2009	2010
UG Mining	2,968		1,663	1,693	1,698	2,102	2,360	2,459
Liberated	3,234		2,389	2,588	2,422	2,881	3,149	3,402
Recovered & Used	(265.9)		(726.0)	(894.7)	(723.7)	(778.5)	(789.2)	(942.9)
Surface Mining	573.6		633.1	668.0	658.9	680.5	614.2	626.2
Post-Mining (UG)	368.3		305.9	298.5	289.6	292.0	266.7	270.2
Post-Mining (Surface)	93.2		102.9	108.5	107.1	110.6	99.8	101.8
Total	**4,003**		**2,705**	**2,768**	**2,754**	**3,186**	**3,340**	**3,458**

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[102] 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.

[102] 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.

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 2010, 14 active coal mines sold recovered CH_4 into the local gas pipeline networks and one coal mine used recovered CH_4 on site for heating. 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. Data was not available for CDX wells for 2010, thus underground emissions avoided were estimated for two mines. Emissions avoided were estimated using a 10-year average for the Pinnacle Mine and a 2-year average for the Road Fork 51 Mine.

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 3-30) (EIA 2011), 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 3-30: Coal Production (Thousand Metric Tons)

Year	Underground	Surface	Total
1990	384,244	546,808	931,052
2005	334,398	691,448	1,025,846
2006	325,697	728,447	1,054,144
2007	319,139	720,023	1,039,162
2008	323,932	737,832	1,061,764
2009	301,241	671,475	972,716
2010	305,862	693,732	999,594

Uncertainty and Time-Series Consistency

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 3-31. Coal mining CH_4 emissions in 2009 were

estimated to be between 63.0 and 84.4 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 13.2 percent below to 16.3 percent above the 2010 emission estimate of 72.6 Tg CO_2 Eq.

Table 3-31: Tier 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Coal Mining (Tg CO_2 Eq. and Percent)

Source	Gas	2010 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	72.6	63.0	84.4	-13.2%	+16.3%

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

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2010. Details on the emission trends through time are described in more detail in the Methodology section, above.

Recalculations Discussion

For the current inventory, updated mine maps were received for the Oak Grove and Jim Walter Resources (JWR) mines, which provided a more accurate depiction of the dates that certain pre-drainage CMM wells were mined through. As a result, the mined-through dates were adjusted for some wells based on updated mine plans, and underground emissions avoided values changed slightly from 2005 to 2009.

3.5. 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 2010, 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 2010, with only five closures in 2010. By 2010, gross abandoned mine emissions decreased slightly to 7.6 Tg CO_2 Eq. (see Table 3-32 and Table 3-33). Gross emissions are reduced by CH_4

recovered and used at 38 mines, resulting in net emissions in 2010 of 5.0 Tg CO_2 Eq.

Table 3-32: CH_4 Emissions from Abandoned Coal Mines (Tg CO_2 Eq.)

Activity	1990		2005	2006	2007	2008	2009	2010
Abandoned Underground Mines	6.0		7.0	7.6	8.9	9.0	8.1	7.6
Recovered & Used	+		1.5	2.2	3.6	3.7	3.0	2.7
Total	**6.0**		**5.5**	**5.5**	**5.3**	**5.3**	**5.1**	**5.0**

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

Table 3-33: CH_4 Emissions from Abandoned Coal Mines (Gg)

Activity	1990		2005	2006	2007	2008	2009	2010
Abandoned Underground Mines	288		334	364	425	429	388	364
Recovered & Used	+		70	103	172	177	143	126
Total	**288**		**264**	**261**	**254**	**253**	**244**	**237**

+ Does not exceed 0.05 Tg CO_2 Eq.
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 that depends 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 also 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, Pr, declines as described by the isotherm. The emission rate declines because the mine pressure (Pw) is essentially constant at atmospheric pressure, for a vented mine, and the productivity index (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:

$$q = q_i (1+bD_it)^{(-1/b)}$$

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).

$$q = q_{ie}^{(-Dt)}$$

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 × (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 469 abandoned mines closing after 1972 produced emissions greater than 100 mcfd when active. Further, the status of 273 of the 469 mines (or 58 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 42 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 3-34: 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.	25	25	48	98	129	227
Illinois	30	3	14	47	26	73
Northern Appl.	42	22	16	80	36	116
Warrior Basin	0	0	16	16	0	16
Western Basins	27	3	2	32	10	42
Total	**124**	**53**	**96**	**273**	**196**	**474**

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 seventeen mines that closed between 1992 and 2010. 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 2010, 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 and Time-Series Consistency

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 3-35. Abandoned coal mines CH_4 emissions in 2010 were estimated to be between 3.88 and 6.05 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 22 percent below to 21 percent above the 2010 emission estimate of 4.98 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 42 percent of the mines), with a ±51 percent uncertainty.

Table 3-35: Tier 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Abandoned Underground Coal Mines (Tg CO_2 Eq. and Percent)

Source	Gas	2010 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	4.98	3.88	6.05	-22%	+21%

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

Recalculations Discussion

After last year's submission of the 1990-2009 Inventory, a small error in the calculations spreadsheet for Abandoned

Underground Coal Mines was discovered. This error was fixed in preparation of this year's Inventory and as a result some of the emissions estimates for this source category in past years differ from last year's report. No new data or methodologies were used to recalculate these values.

3.6. 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 215.4 Tg CO_2 Eq. (10,259 Gg) of CH_4 in 2010, a 14 percent increase over 1990 emissions (see Table 3-36 and Table 3-37) and 32.3 Tg CO_2 Eq. (32,301 Gg) of non-combustion CO_2 in 2010, a 14 percent decrease over 1990 emissions (see Table 3-38 and Table 3-39). Improvements in management practices and technology, along with the replacement of older equipment, have helped to stabilize emissions. Methane emissions increased since 2008 due to an increase in production and production wells.

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. Emissions from pneumatic devices, gas wells with liquids unloading, and gas well completions and re-completions (workovers) with and without hydraulic fracturing 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 58 percent of CH_4 emissions and about 34 percent of non-combustion CO_2 emissions from natural gas systems in 2010.

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 8 percent of CH_4 emissions and approximately 66 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 20 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 1,202,000 miles of distribution mains in 2010, an increase of approximately 258,000 miles since 1990 (OPS 2010b). Distribution system emissions, which account for approximately 13 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. 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 2010 were 15 percent lower than 1990 levels.

Table 3-36 and Table 3-37 show total CH_4 emissions for the four major stages of natural gas systems, in Tg CO2 Eq (Table 3-36) and Gg (Table 3-37). Table 3-38 gives more information on how the numbers in 3-36 were calculated. Table 3-38 shows the calculated CH_4 release (i.e. potential emissions before any controls are applied) from each stage, and the amount of that CH_4 that is estimated to have been flared, captured, or otherwise controlled, and therefore not emitted to the atmosphere. Subtracting the CH_4 that is controlled from the quantity of CH_4 that was calculated to be released results in the emissions totals.

Table 3-36: CH_4 Emissions from Natural Gas Systems (Tg CO_2 Eq.)*

Stage	1990		2005	2006	2007	2008	2009	2010
Field Production	89.0		105.2	133.8	117.8	123.2	129.4	126.0
Processing	18.0		14.6	14.8	15.5	16.2	17.8	17.1
Transmission and Storage	49.2		41.4	40.9	42.5	43.3	44.7	43.8
Distribution	33.4		29.3	28.3	29.4	29.9	29.1	28.5
Total	**189.6**		**190.5**	**217.7**	**205.3**	**212.7**	**220.9**	**215.4**

*These values represent CH_4 emitted to the atmosphere. CH_4 that is captured (and not emitted to the atmosphere) has been calculated and removed from emission totals.
Note: Totals may not sum due to independent rounding.

Table 3-37: CH_4 Emissions from Natural Gas Systems (Gg)*

Stage	1990		2005	2006	2007	2008	2009	2010
Field Production	4,240		5,011	6 ,370	5,611	5,869	6,161	6,002
Processing	855		694	704	737	770	837	812
Transmission and Storage	2,343		1,971	1,949	2,024	2,062	2,127	2,086
Distribution	1,591		1,395	1,346	1,402	1,426	1,384	1,359
Total	**9,029**		**9,071**	**10,369**	**9,774**	**10,127**	**10,519**	**10,259**

* These values represent CH_4 emitted to the atmosphere. CH_4 that is captured (and not emitted to the atmosphere) has been calculated and removed from emission totals.
Note: Totals may not sum due to independent rounding.

Table 3-38: Calculated Potential CH_4 and Captured/Combusted CH_4 from Natural Gas Systems (Tg CO_2 Eq.)

	1990		2005	2006	2007	2008	2009	2010
Calculated Potential‡	**189.4**		**240.2**	**295.7**	**274.2**	**293.3**	**288.5**	**288.6**
Field Production	88.9		141.0	197.8	173.7	191.2	186.9	185.9
Processing	17.9		17.3	17.7	18.2	19.0	19.3	20.1
Transmission and Storage	49.2		51.9	51.0	52.0	52.6	52.5	53.0
Distribution	33.4		30.0	29.3	30.2	30.5	29.9	29.6
Captured/Combusted	**(0.2)***		**49.7**	**77.9**	**68.9**	**80.6**	**67.6**	**73.1**
Field Production	+		35.8	64.0	55.9	67.9	57.5	59.8
Processing	+		2.7	2.9	2.8	2.8	1.5	3.0
Transmission and Storage	+		10.5	10.1	9.5	9.2	7.8	9.2
Distribution	+		0.7	1.0	0.8	0.6	0.9	1.1
Net Emissions	**189.6**		**190.5**	**217.7**	**205.3**	**212.7**	**220.9**	**215.4**
Field Production	89.0		105.2	133.8	117.8	123.2	129.4	126.0
Processing	18.0		14.6	14.8	15.5	16.2	17.8	17.1
Transmission and Storage	49.2		41.4	40.9	42.5	43.3	44.7	43.8
Distribution	33.4		29.3	28.3	29.4	29.9	29.1	28.5

Note: Totals may not sum due to independent rounding.
*The base year of the factors used is 1992; for reductions reported between 1990 and 1992, it is assumed that reductions are already taken into account in the Calculated Potential values and the reduction is added back into the estimate for the

appropriate year(s). For 1990, this table shows the value added back into the estimate.
+ Emissions are less than 0.1 Tg CO_2 Eq.
‡ In this context, "potential" means the total emissions calculated before voluntary reductions/regulatory controls are applied.

Table 3-39: Non-combustion CO_2 Emissions from Natural Gas Systems (Tg CO_2 Eq.)

Stage	1990	2005	2006	2007	2008	2009	2010
Field Production	9.7	8.0	9.4	9.7	11.3	10.9	10.8
Processing	27.8	21.7	21.2	21.2	21.4	21.2	21.3
Transmission and Storage	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Distribution	+	+	+	+	+	+	+
Total	**37.6**	**29.9**	**30.8**	**31.0**	**32.8**	**32.2**	**32.3**

Note: Totals may not sum due to independent rounding.
+ Emissions are less than 0.1 Tg CO_2 Eq.

Table 3-40: Non-combustion CO_2 Emissions from Natural Gas Systems (Gg)

Stage	1990	2005	2006	2007	2008	2009	2010
Field Production	9,703	8,049	9,437	9,745	11,335	10,875	10,848
Processing	27,763	21,746	21,214	21,199	21,385	21,188	21,346
Transmission and Storage	62	64	63	64	65	65	65
Distribution	46	41	40	41	42	41	41
Total	**37,574**	**29,901**	**30,754**	**31,049**	**32,826**	**32,169**	**32,301**

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 factors to characterize emissions from the various components within the operating stages of the U.S. natural gas system. The same factors were used to estimate both CH_4 and non-combustion CO_2 emissions. CO_2 factors were developed using the CH_4 emission factors and average CO_2 and CH_4 content of gas. 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 factors and activity data drivers from the study, except where direct activity data was available (e.g., offshore platform counts, processing plant counts, transmission pipeline miles, and distribution pipelines). For other years, a set of industry activity data drivers was developed that can be used to update activity data, where such data is not directly available. 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.

Although the inventory primarily uses EPA/GRI emission factors, significant improvements were made to the emissions estimates for three sources with last year's inventory: gas wells with liquids unloading, condensate storage tanks and centrifugal compressors. In addition, data for two sources not included in the EPA/GRI study – gas well completions and gas well workovers (re-completions) with hydraulic fracturing- were added. In the case of gas wells with liquids unloading, the methodology was revised to use a large sample of well and reservoir characteristics from the HPDI database (HPDI 2009) along with an engineering statics equation (EPA 2006a) to estimate the volume of natural gas necessary to expel a liquid column choking the well production. See Annex 3.4 for more information on the methodology for gas wells with liquids unloading. For condensate storage tanks, sample E&P Tank runs were used as was the case in previous inventories; however, the factor was improved by using a large sample distribution of condensate production by gravity from the HPDI database (HPDI 2009) to weigh the sample simulation flashing emissions rather than assuming a uniform distribution of condensate gravities. Additionally, TERC (TERC 2009) data representing two regions was used in the emission factors for those two regions to estimate the effects of separator dump valves malfunctioning and allowing natural gas to vent through the downstream condensate storage tanks. The EPA/GRI emission factor for centrifugal compressors (used in earlier

inventories) was derived from sampled emissions at the seal face of wet seal compressors. A World Gas Conference publication (WGC 2009) on the seal oil degassing vents was used to update this factor and to also account for the emergence of dry seal centrifugal compressors (EPA 2006b), which eliminates seal oil degassing vents and reduces overall emissions. For more information on this factor, see Annex 3.4. Previous Inventories did not differentiate between wells without hydraulic fracturing and with hydraulic fracturing for completions and workovers. Gas well completions and workovers with hydraulic fracturing were not common at the time the EPA/GRI survey was conducted. Since then, these activities have become more prevalent and emissions data on this activity has become available through a number of sources. Using this data, an emission factor was developed for gas well completions and workovers with hydraulic fracturing. 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.

The emissions factors described above represent expected emissions from an activity, and do not take into account use of technologies that reduce emissions. To take into account use of such technologies, data is collected on regulatory and voluntary reductions. For more information on these reductions, please see the Annex. The numbers presented in tables 3-36 and 3-37 are the CH_4 that is emitted to the atmosphere (i.e., net emissions), not potential emissions without capture or flaring.

Activity data were taken from the following sources: American Gas Association (AGA 1991–1998); Bureau of Ocean Energy Management, Regulation and Enforcement (previous Minerals and Management Service) (BOEMRE 2010a-d); Monthly Energy Review (EIA 2010f); Natural Gas Liquids Reserves Report (EIA 2005); Natural Gas Monthly (EIA 2010b,c,e); the Natural Gas STAR Program annual emissions savings (EPA 2010); Oil and Gas Journal (OGJ 1997–2010); Office of Pipeline Safety (OPS 2010a-b); Federal Energy Regulatory Commission (FERC 2010) and other Energy Information Administration publications (EIA 2001, 2004, 2010a,d); World Oil Magazine (2010a-b). Data for estimating emissions from hydrocarbon production tanks were incorporated (EPA 1999). Coalbed CH_4 well activity factors were taken from the Wyoming Oil and Gas Conservation Commission (Wyoming 2009) and the Alabama State Oil and Gas Board (Alabama 2010). Other state well data was taken from: American Association of Petroleum Geologists (AAPG 2004); Brookhaven College (Brookhaven 2004); Kansas Geological Survey (Kansas 2010); Montana Board of Oil and Gas Conservation (Montana 2010); Oklahoma Geological Survey (Oklahoma 2010); Morgan Stanley (Morgan Stanley 2005); Rocky Mountain Production Report (Lippman 2003); New Mexico Oil Conservation Division (New Mexico 2010, 2005); Texas Railroad Commission (Texas 2010a-d); Utah Division of Oil, Gas and Mining (Utah 2010). 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 and adjust CH_4 emission factors from the EPA/GRI survey. Methane compositions from GTI 2001 are adjusted year to year using gross production by NEMS for oil and gas supply regions from the EIA. Therefore, emission factors may vary from year to year due to slight changes in the CH_4 composition for each NEMS oil and gas supply module region. Additional information about CO_2 content in transmission quality natural gas was obtained from numerous U.S. transmission companies to help further develop the non-combustion CO_2 emission factors.

Uncertainty and Time-Series Consistency

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 @RISK model utilizes 1992 (base year) emissions to quantify the uncertainty associated with the emissions estimates using the top twelve emission sources for the year 2010.

The results presented below provide with 95 percent certainty the range within which emissions from this source category are likely to fall for the year 2010. 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 are summarized in Table 3-41. Natural gas systems CH_4 emissions in 2010 were estimated to be between 174.5 and 280.0 Tg CO_2 Eq. at a 95 percent confidence level. Natural gas systems non-energy CO_2 emissions in 2010 were estimated to be between 26.2 and 42.0 Tg CO_2 Eq. at 95 percent confidence level.

Table 3-41: Tier 2 Quantitative Uncertainty Estimates for CH_4 and Non-energy CO_2 Emissions from Natural Gas Systems (Tg CO_2 Eq. and Percent)

Source	Gas	2010 Emission Estimate (Tg CO_2 Eq.)[c]	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound[c]	Upper Bound[c]	Lower Bound[c]	Upper Bound[c]
Natural Gas Systems	CH_4	215.4	174.5	280.0	-19%	+30%
Natural Gas Systems[b]	CO_2	32.3	26.2	42.0	-19%	+30%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.
[b] An uncertainty analysis for the non-energy 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-energy CO_2 emissions.
[c] All reported values are rounded after calculation. As a result, lower and upper bounds may not be duplicable from other rounded values as shown in table.

QA/QC and Verification Discussion

The natural gas inventory is continually being reviewed and assessed to determine whether emission factors and activity factors accurately reflect current industry practice. A QA/QC analysis was performed for data gathering and input, documentation, and calculation. In addition, through regulations, public webcasts, and the Natural Gas STAR Program, EPA performs a QA/QC check to determine the assumptions in the Inventory are consistent with current industry practices. Finally, QA/QC checks are consistently conducted to minimize human error in the model calculations.

As a result of the QA/QC checks, two corrections were made in the current Natural Gas Systems estimates. First, the calculation for the CH_4 content was corrected. The CH_4 content is adjusted for each year by the gross production of natural gas in each state as reported by the EIA. In the previous Inventory, the CH_4 content was adjusted incorrectly by including state production totals for which there was no CH_4 content data. The current Inventory correctly makes a minor adjustment to the CH_4 content using only state productions for which CH_4 content is available. Second, emission factors for fugitive emissions from gas wells (i.e., equipment leaks from valves, connectors, and open ended lines on or associated with the wellhead) were corrected. For several NEMS regions these fugitive emission factors from the 1996 GRI study were missing or inconsistent with the study.

Recalculations Discussion

EPA has received information and data related to the emissions estimates through the inventory preparation process and the formal public notice and comment process of the proposed oil and gas new source performance standards (NSPS) for VOCs. EPA plans to carefully evaluate this and all other relevant information provided. Subsequently, all relevant updates will then be incorporated, as applicable, in the next cycle of the Inventory. See Planned Improvements below. In light of this current review of information and data, for the current Inventory, emissions for the natural gas sector were calculated using the same methodologies, emission factors, and sources of activity data as the 1990-2009 Inventory report. Additionally, EPA has used the estimates for emissions from completions and workovers hydraulically fractured wells from the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009* (i.e., maintained the same activity data and voluntary reductions for hydraulically fractured gas well completions and existing hydraulically fractured gas wells), holding constant the 2009 value for the 2010 estimate. Note that the estimates provided in the public review draft were changed because several values for hydraulically fractured well completions had been updated over the time series. Removing these updates resulted in a change of in total sector CH_4 emissions of 0.3 percent over the time series from the public review draft.

Some of the calculated emissions for the 1990 through 2009 times series have changed from the previous Inventory report due to corrections noted above in QA/QC and Verification Discussion.

Planned Improvements

EPA is considering a number of potential improvements for the Natural Gas Systems inventory.

For the production sector, EPA intends to evaluate additional data on emission reductions, particularly those related

to gas wells with liquids unloading, and voluntary and regulatory reductions from well completions and, if appropriate, will incorporate revisions into future inventories. Evaluation of reductions associated with liquids unloading will include review of data on controls such as plunger lifts and other artificial lift technologies as appropriate. Additionally, accounting for the uncertainty of emission reductions to more accurately provide upper and lower bounds within the 95 percent confidence interval will be investigated. EPA also intends to investigate improvements to its estimates of emissions from hydraulic fracturing, including revisiting the estimates for workover frequency and the number of well completions. The current method for determining hydraulically fractured gas well completion counts relies on data from state websites. Using this method, gas well counts are limited to those that are published online and, therefore, the number of wells is not entirely complete. Subsequently, an underestimate of the number of gas well completions is expected.

In the storage sector, the emission factors in the Inventory account for flashing emissions from condensate tanks. Measurement studies and anecdotal evidence suggest that, in some cases, produced gas from the separator will bypass the liquid dump valve and vent through the storage tank, which is not taken into account in the current estimates. New data on this source will be reviewed as it becomes available and emissions will be updated, as appropriate.

Data collected through EPA's Greenhouse Gas Reporting Program (40 CFR Part 98, Mandatory Reporting of Greenhouse Gases; Final Rule, Subpart W) will be reviewed for potential improvements to the natural gas systems emission estimates. The rule will collect actual activity data using improved quantification methods from those used in several of the studies which form the basis of the Natural Gas Systems emission estimates. Data collection for Subpart W began January 1, 2011 with emissions reporting beginning in 2012. These data will be reviewed for inclusion into a future Inventory to improve the accuracy and reduce the uncertainty of the emission estimates.

As discussed above, EPA has received information and data related to the emissions estimates through the inventory preparation process and the formal public notice and comment process of the proposed oil and gas new source performance standards (NSPS) for VOCs. EPA plans to carefully evaluate this and all other relevant information provided to us. Subsequently, all relevant updates will then be incorporated, as applicable, in the next cycle of the Inventory.

Finally, EPA is also considering improvements to the documentation of the Natural Gas Systems source category. EPA is considering including a table matching each emission factor and activity factor with its source or calculation methodology. The purpose of this improvement would be to make the calculation methodologies more transparent. In addition, EPA is considering adding additional tables to Annex 3.4 to show activity data and emission factors for previous years. EPA also plans on revising the emissions tables in Annex 3.4 to show voluntary reductions broken out for key emission sources.

3.7. Petroleum Systems (IPCC Source Category 1B2a)

Methane 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 refining operations but are negligible in transportation operations. Combustion CO_2 emissions from fuels are already accounted for in the Fossil Fuels Combustion source category, and hence have not been taken into account in the Petroleum Systems source category. Total CH_4 and CO_2 emissions from petroleum systems in 2010 were 31.1 Tg CO_2 Eq. (1,478 Gg CH_4) and 0.3 Tg CO_2 (337 Gg), respectively. Since 1990, CH_4 emissions have declined by 11.8 percent, due to industry efforts to reduce emissions and a decline in domestic oil production (see Table 3-42 and Table 3-43). CO_2 emissions have also declined by 14.4 percent since 1990 due to similar reasons (see Table 3-44 and Table 3-45).

Production Field Operations. Production field operations account for 98.4 percent of total CH_4 emissions from petroleum systems. Vented CH_4 from field operations account for approximately 90 percent of the emissions from the production sector, uncombusted CH_4 emissions (i.e. unburned fuel) account for 6.4 percent, fugitive emissions are 3.5 percent, and process upset emissions are slightly over two-tenths of a percent. The most dominant sources of emissions, in order of magnitude, are shallow water offshore oil platforms, natural-gas-powered high bleed pneumatic devices, oil tanks, natural-gas powered low bleed pneumatic devices, gas engines, deep water offshore platforms, and chemical injection pumps. These seven sources alone emit about 94 percent of the production field operations emissions. Offshore platform emissions are a combination of fugitive, vented, and uncombusted fuel

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 oil 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 of such pumps that use associated gas to drive pneumatic pumps. The remaining six 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 CH_4 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 from production field operations, while fugitive and process upsets together account for less than 1 percent of the emissions. The most dominant sources of vented emissions are oil tanks, high bleed pneumatic devices, shallow water offshore oil platforms, low bleed pneumatic devices, and chemical injection pumps. These five sources together account for 98.5 percent of the non-combustion CO_2 emissions from production field operations, 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 0.5 percent of total CH_4 emissions from the oil industry. Venting from tanks and marine vessel loading operations accounts for 60.3 percent of CH_4 emissions from crude oil transportation. Fugitive emissions, almost entirely from floating roof tanks, account for 18.5 percent. The remaining 21 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 less than 1.5 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 81 percent of the emissions, while fugitive and combustion emissions account for approximately nine and nine and half 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.

Asphalt blowing from crude oil refining accounts for 4.5 percent of the total non-combustion CO_2 emissions in petroleum systems.

Table 3-42: CH_4 Emissions from Petroleum Systems (Tg CO_2 Eq.)

Activity	1990		2005	2006	2007	2008	2009	2010
Production Field Operations	**34.7**		**28.7**	**28.7**	**29.3**	**29.5**	**30.2**	**30.6**
Pneumatic device venting	10.3		8.3	8.3	8.4	8.7	8.8	8.8
Tank venting	5.3		3.9	3.9	4.0	3.8	4.3	4.5
Combustion & process upsets	1.9		1.5	1.5	1.5	1.6	2.0	2.0
Misc. venting & fugitives	16.8		14.5	14.5	15.0	14.8	14.6	14.7
Wellhead fugitives	0.6		0.4	0.4	0.4	0.5	0.5	0.5
Crude Oil Transportation	**0.1**		**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Refining	**0.4**		**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**
Total	**35.2**		**29.2**	**29.2**	**29.8**	**30.0**	**30.7**	**31.0**

Note: Totals may not sum due to independent rounding.

Table 3-43: CH_4 Emissions from Petroleum Systems (Gg)

Activity	1990		2005	2006	2007	2008	2009	2010
Production Field Operations	**1,653**		**1,365**	**1,365**	**1,396**	**1,404**	**1,437**	**1,455**
Pneumatic device venting	489		397	396	398	416	419	420
Tank venting	250		187	188	192	182	206	214
Combustion & process upsets	88		71	71	72	75	94	97
Misc. venting & fugitives	799		690	692	714	706	693	700

Wellhead fugitives	26		19	17	20	24	24	24
Crude Oil Transportation	**7**		**5**	**5**	**5**	**5**	**5**	**5**
Refining	**18**		**19**	**19**	**19**	**19**	**18**	**19**
Total	**1,677**		**1,389**	**1,389**	**1,420**	**1,427**	**1,460**	**1,478**

Note: Totals may not sum due to independent rounding.

Table 3-44: CO_2 Emissions from Petroleum Systems (Tg CO_2 Eq.)

Activity	1990		2005	2006	2007	2008	2009	2010
Production Field Operations	**0.4**		**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**
Pneumatic device venting	+		+	+	+	+	+	+
Tank venting	0.3		0.2	0.2	0.3	0.2	0.3	0.3
Misc. venting & fugitives	+		+	+	+	+	+	+
Wellhead fugitives	+		+	+	+	+	+	+
Crude Refining	**+**		**+**	**+**	**+**	**+**	**+**	**+**
Total	**0.39**		**0.31**	**0.31**	**0.31**	**0.30**	**0.33**	**0.34**

+ Does not exceed 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding.

Table 3-45: CO_2 Emissions from Petroleum Systems (Gg)

Activity	1990		2005	2006	2007	2008	2009	2010
Production Field Operations	**376**		**285**	**285**	**292**	**280**	**311**	**322**
Pneumatic device venting	27		22	22	22	23	23	23
Tank venting	328		246	246	252	239	270	281
Misc. venting & fugitives	18		16	16	16	16	16	16
Wellhead fugitives	1		1	1	1	1	1	1
Crude Refining	**18**		**20**	**20**	**18**	**16**	**14**	**15**
Total	**394**		**305**	**306**	**310**	**297**	**325**	**337**

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 negligible.

The methodology for estimating CH_4 emissions from the 64 oil industry activities employs emission factors initially developed by EPA (1999). Activity data for the years 1990 through 2010 were collected from a wide variety of statistical resources. Emissions are estimated for each activity by multiplying emission factors (e.g., emission rate per equipment item or per activity) by the corresponding activity data (e.g., equipment count or frequency of activity). EPA (1999) provides emission 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, BOEMRE 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 2010. The number of platforms in shallow water and the number of platforms in deep water are used as activity data and are taken from Bureau of Ocean Energy Management, Regulation, and Enforcement (BOEMRE) (formerly Minerals Management Service) statistics (BOEMRE 2011a-c). For oil storage tanks, the emissions factor was calculated as the total emissions per barrel of crude charge from E&P Tank data weighted by the distribution of produced crude oil gravities from the HPDI production database (EPA 1999, HPDI 2010).

For some years, complete activity data were not available. In such cases, one of three approaches was employed. Where appropriate, the activity data 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 data for heater treaters, reported statistics for wells and production were used, along with the ratios developed for EPA (1996). In other cases, the activity data was held constant from 1990 through 2010 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 data. See Annex 3.5 for additional detail.

Key references used to obtain activity data are the Energy Information Administration annual and monthly reports (EIA 1990 through 2010, 1995 through 2010, 1995 through 2010a-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, BOEMRE reports (BOEMRE 2005, 2010a-c), analysis of BOEMRE data (EPA 2005, BOEMRE 2004), the Oil & Gas Journal (OGJ 2011a,b), the Interstate Oil and Gas Compact Commission (IOGCC 2009, and the United States Army Corps of Engineers (1995-2009).

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 and one activity from petroleum refining. Emissions are estimated for each activity by multiplying emission factors by their corresponding activity data. 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 E&P Tank simulation runs, and the emission factor for asphalt blowing, which was derived using the methodology and sample data from API (2009).

Uncertainty and Time-Series Consistency

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 Stochastic 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 to 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 92 percent of the total methane 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 3-46. Petroleum systems CH_4 emissions in 2010 were estimated to be between 23.64 and 77.31 Tg CO_2 Eq., while CO_2 emissions were estimated to be between 0.26 and 0.85 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 24 percent below to 149 percent above the 2010 emission estimates of 31.05 and 0.34 Tg CO_2 Eq. for CH_4 and CO_2, respectively.

Table 3-46: Tier 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Petroleum Systems (Tg CO_2 Eq. and Percent)

Source	Gas	2010 Emission Estimate (Tg CO_2 Eq.)[b]	Uncertainty Range Relative to Emission Estimate[a]			
			(Tg CO_2 Eq.)		(%)	
			Lower Bound[b]	Upper Bound[b]	Lower Bound[b]	Upper Bound[b]
Petroleum Systems	CH_4	31.05	23.64	77.31	-24%	149%
Petroleum Systems	CO_2	0.34	0.26	0.85	-24%	149%

[a] Range of 2010 relative uncertainty predicted by Monte Carlo Stochastic Simulation, based on 1995 base year activity factors, for a 95 percent confidence interval.
[b] All reported values are rounded after calculation. As a result, lower and upper bounds may not be duplicable from other rounded values as shown in table.
Note: Totals may not sum due to independent rounding

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2010. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification Discussion

The petroleum inventory is continually being reviewed and assessed to determine whether emission factors and activity factors accurately reflect current industry practice. A QA/QC analysis was performed for data gathering and input, documentation, and calculation. The primary focus of the QA/QC checks is determining if the assumptions in the Inventory are consistent with current industry practices through regulations, public webcasts, and the Natural Gas STAR Program. Finally, QA/QC checks are consistently conducted to minimize human error in the model calculations.

A webcast was held by EPA for industry to comment on the ratio of high-bleed to low-bleed pneumatics, among other topics. Two of the top seven emission sources, high-bleed and low-bleed pneumatic devices, use the earlier mentioned industry peer review panel activity source (EPA/GRI 1996c). The Inventory assumes four pneumatic devices per well-site with a heater-treater and separator, and three pneumatic devices per well-site with a separator but without a heater-treater. EPA requested industry's views on the assumption that, for each year of the time series (1990 to 2010), 35 percent of devices are high-bleed pneumatic devices. No new information was raised, nor concerns expressed, about this factor during the webcast and therefore this factor has not changed in the current inventory.

Additionally, the webcast discussed the emission factor for a refinery source, asphalt blowing. EPA requested comment on the current CH_4 emission factor for asphalt blowing (derived from a Radian International Study) versus the 2009 API Compendium's CH_4 emission factor. The emission factor from the current Inventory was not modified as a result of these comments; however, the activity for asphalt blowing was modified by applying a 10 percent factor to the activity obtained through EIA's Petroleum Supply Annual. This was based on asphalt market analysis.

Recalculations Discussion

Most revisions for the current Inventory relative to the previous report were due to updating previous years' data with revised data from existing data sources. Well completion venting, well drilling, and offshore platform activity factors were updated with revised data from existing data sources from 1990 onward. Updating the activity data for asphalt blowing reduced CH_4 and CO_2 emissions for this source by a factor of 10, which has a relatively large impact on fugitive emissions from petroleum refineries, but due to the small contribution of refineries to the overall fugitive emissions, a relatively small impact on the overall greenhouse gas emission estimates from petroleum systems.

In addition, when activity data updates are made for a particular emissions source the entire time series is revised or corrected, which may result in slight changes in estimated emissions from past years..

Planned Improvements

In 2010, all U.S. petroleum refineries were required to collect information on their greenhouse gas emissions. This data was reported to EPA through its GHGRP in 2011. Data collected under this program will be evaluated for use in future inventories to improve the calculation of national emissions from petroleum systems. In particular, whether certain emissions sources currently accounted for in the Energy sector should be separately accounted for in the petroleum systems source category estimates (e.g., CO_2 process emissions from hydrogen production) will be investigated.

Improvements to the documentation of the Petroleum Systems source category is also being considered. A table matching each emission factor and activity factor with its source or calculation methodology is being considered. The purpose of this improvement would be to make the calculation methodologies more transparent.

[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 Production sections of the Inventory report, respectively.

IPCC (IPCC 2006) included, 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 (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.

As of January 1, 2011, facilities that conduct geologic sequestration of CO_2 and all other facilities that inject CO_2 underground are required to calculate and report greenhouse gas data annually to EPA through its GHGRP. EPA's GHGRP requires greenhouse gas reporting from facilities that inject CO_2 underground for geologic sequestration,

and requires greenhouse gas reporting from all other facilities that inject CO_2 underground for any reason, including enhanced oil and gas recovery. Facilities conducting geologic sequestration of CO_2 are required to develop and implement an EPA-approved site-specific monitoring, reporting and verification (MRV) plan, and to report the amount of CO_2 sequestered using a mass balance approach. Data from this program, which will be reported to EPA starting in 2012, for the 2011 calendar year, will provide additional facility-specific information about the carbon capture, transport and storage chain. That information will be evaluated closely and opportunities for improving the emission estimates will be considered.

Preliminary estimates indicate that the amount of CO_2 captured from industrial and natural sites is 46.2 Tg CO_2 (46,198 Gg CO_2) (see Table 3-47and Table 3-48). 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 3-47: Potential Emissions from CO_2 Capture and Transport (Tg CO_2 Eq.)

Year	1990		2005	2006	2007	2008	2009	2010
Acid Gas Removal Plants	4.8		5.8	6.2	6.4	6.6	7.0	11.6
Naturally Occurring CO_2	20.8		28.3	30.2	33.1	36.1	39.7	34.0
Ammonia Production Plants	+		0.7	0.7	0.7	0.6	0.6	0.7
Pipelines Transporting CO_2	+		+	+	+	+	+	+
Total	**25.6**		**34.7**	**37.1**	**40.1**	**43.3**	**47.3**	**46.2**

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

Table 3-48: Potential Emissions from CO_2 Capture and Transport (Gg)

Year	1990		2005	2006	2007	2008	2009	2010
Acid Gas Removal Plants	4,832		5,798	6,224	6,088	6,630	7,035	11,554
Naturally Occurring CO_2	20,811		28,267	30,224	33,086	36,102	39,725	33,967
Ammonia Production Plants	+		676	676	676	580	580	677
Pipelines Transporting CO_2	8		7	7	7	8	8	8
Total	**25,643**		**34,742**	**37,124**	**40,141**	**43,311**	**47,340**	**46,198**

+ Does not exceed 0.5 Gg.
Note: Totals do not include emissions from pipelines transporting CO_2
Note; Totals may not sum due to independent rounding.

[END BOX]

3.8. 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 2010 are reported in Table 3-49.

Table 3-49: NO_x, CO, and NMVOC Emissions from Energy-Related Activities (Gg)

Gas/Source	1990		2005	2006	2007	2008	2009	2010
NO_x	**21,106**		**15,319**	**14,473**	**13,829**	**13,012**	**10,887**	**10,887**
Mobile Combustion	10,862		9,012	8,488	7,965	7,441	6,206	6,206
Stationary Combustion	10,023		5,858	5,545	5,432	5,148	4,159	4,159
Oil and Gas Activities	139		321	319	318	318	393	393
Incineration of Waste	82		129	121	114	106	128	128
*International Bunker Fuels**	*2,020*		*1,703*	*1,794*	*1,791*	*1,917*	*1,651*	*1,812*
CO	**125,640**		**69,062**	**65,399**	**61,739**	**58,078**	**49,647**	**49,647**
Mobile Combustion	119,360		62,692	58,972	55,253	51,533	43,355	43,355
Stationary Combustion	5,000		4,649	4,695	4,744	4,792	4,543	4,543

Incineration of Waste	978	1,403	1,412	1,421	1,430	1,403	1,403
Oil and Gas Activities	302	318	319	320	322	345	345
*International Bunker Fuels**	*130*	*132*	*161*	*160*	*165*	*149*	*152*
NMVOCs	**12,620**	**7,798**	**7,702**	**7,604**	**7,507**	**5,333**	**5,333**
Mobile Combustion	10,932	6,330	6,037	5,742	5,447	4,151	4,151
Stationary Combustion	912	716	918	1,120	1,321	424	424
Oil and Gas Activities	554	510	510	509	509	599	599
Incineration of Waste	222	241	238	234	230	159	159
*International Bunker Fuels**	*61*	*54*	*59*	*59*	*62*	*57*	*58*

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

Methodology

Due to the lack of data available at the time of publication, emission estimates for 2010 rely on 2009 data as a proxy. Emission estimates for 2009 were obtained from preliminary data (EPA 2010, EPA 2009), 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 and Time-Series Consistency

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.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2010. Details on the emission trends through time are described in more detail in the Methodology section, above.

3.9. 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 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.[103] These decisions are reflected in the IPCC methodological guidance, including the 2006 IPCC Guidelines, 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 2006).[104]

Greenhouse gases emitted from the combustion of international bunker fuels, like other fossil fuels, include CO_2,

[103] 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).

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

CH_4 and N_2O. Two transport modes are addressed under the IPCC definition of international bunker fuels: aviation and marine.[105] 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.[106]

Emissions of CO_2 from aircraft are essentially a function of fuel use. Methane and N_2O emissions also depend upon engine characteristics, flight conditions, and flight phase (i.e., take-off, climb, cruise, decent, and landing). Methane is the product of incomplete combustion and occurs mainly during the landing and take-off phases. Methane may be emitted by gas turbines during idle and by older technology engines, but recent data suggest that little or no CH_4 is emitted by modern engines (Anderson et al. 2011). 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 that are engaged in international transport. Ocean-going ships are generally classified as cargo and passenger carrying, military (i.e., U.S. 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 2010 from the combustion of international bunker fuels from both aviation and marine activities were 129.2 Tg CO_2 Eq., or 14 percent above emissions in 1990 (see Table 3-50 and Table 3-51). Emissions from international flights and international shipping voyages departing from the United States have increased by 56 percent and decreased by 15 percent, respectively, 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 3-50: CO_2, CH_4, and N_2O Emissions from International Bunker Fuels (Tg CO_2 Eq.)

Gas/Mode	1990		2005	2006	2007	2008	2009	2010
CO_2	**111.8**		**109.8**	**128.4**	**127.6**	**133.7**	**122.3**	**127.8**
Aviation	46.4		56.8	74.6	73.8	75.5	68.6	72.5
Marine	65.4		53.0	53.8	53.9	58.2	53.7	55.3
CH_4	**0.2**		**0.1**	**0.2**	**0.2**	**0.2**	**0.1**	**0.2**
Aviation	+		+	+	+	+	+	+
Marine	0.1		0.1	0.1	0.1	0.1	0.1	0.1
N_2O	**1.1**		**1.0**	**1.2**	**1.2**	**1.2**	**1.1**	**1.2**
Aviation	0.5		0.6	0.8	0.8	0.8	0.7	0.7
Marine	0.5		0.4	0.4	0.4	0.5	0.4	0.4
Total	**113.0**		**110.9**	**129.8**	**129.0**	**135.1**	**123.6**	**129.2**

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

[105] 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).
[106] Naphtha-type jet fuel was used in the past by the military in turbojet and turboprop aircraft engines.

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

Gas/Mode	1990	2005	2006	2007	2008	2009	2010
CO_2	**111,828**	**109,765**	**128,413**	**127,643**	**133,730**	**122,338**	**127,841**
Aviation	46,399	56,751	74,581	73,788	75,534	68,614	72,542
Marine	65,429	53,014	53,832	53,856	58,196	53,723	55,299
CH_4	**8**	**7**	**8**	**8**	**8**	**7**	**8**
Aviation	2	2	2	2	2	2	2
Marine	7	5	5	5	6	5	6
N_2O	**3**	**3**	**4**	**4**	**4**	**4**	**4**
Aviation	2	2	2	2	2	2	2
Marine	2	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 (2010) and USAF (1998), and heat content for jet fuel was taken from EIA (2010a). 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) and the 2006 IPCC Guidelines (IPCC 2006). 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 (IPCC 2006). 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 for inventory years 2000 through 2005 were developed using the FAA's System for assessing Aviation's Global Emissions (SAGE) model (FAA 2006). That tool has been incorporated into the Aviation Environmental Design Tool (AEDT), which calculates noise in addition to aircraft fuel burn and emissions for all commercial flights globally in a given year (FAA 2010). Data for inventory years 2006 through 2010 were developed using AEDT. Activity data on commercial aircraft fuel consumption for years 2000 through 2009 were developed with "domestic" defined as only the 50 states and "international bunkers" as departures from the 50 states to a destination outside of the 50 states. For year 2010 the data was provided both with domestic defined as the 50 states -and- separately as the 50 states and U.S. Territories. The 2010 data formats will be produced for future inventories and recalculations of prior inventories.

International aviation bunker fuel consumption from 1990 to 2010 was calculated by assigning the difference between the sum of domestic activity data (in Tbtu) from SAGE and the AEDT, and the reported EIA transportation jet fuel consumption to the international bunker fuel category for jet fuel from EIA (2010a). 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 2011). 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 3-52. 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 2011) for 1990 through 2001, 2007, through 2010, and the Department of Homeland Security's Bunker Report for 2003 through 2006 (DHS 2008). Fuel consumption data for 2002 was interpolated due to inconsistencies in reported fuel consumption data. Activity data on distillate diesel consumption by military vessels departing from U.S. ports were provided by DESC (2011). 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 3-52: Aviation Jet Fuel Consumption for International Transport (Million Gallons)

Nationality	1990		2005	2006	2007	2008	2009	2010
U.S. and Foreign Carriers	4,934		5,944	7,812	7,729	7,912	7,187	7,598
U.S. Military	862		464	403	413	389	370	359
Total	**5,796**		**6,408**	**8,215**	**8,142**	**8,301**	**7,557**	**7,957**

Note: Totals may not sum due to independent rounding.

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

Fuel Type	1990		2005	2006	2007	2008	2009	2010
Residual Fuel Oil	4,781		3,881	4,004	4,059	4,373	4,040	4,141
Distillate Diesel Fuel & Other	617		444	446	358	445	426	476
U.S. Military Naval Fuels	522		471	414	444	437	384	377
Total	**5,920**		**4,796**	**4,864**	**4,861**	**5,254**	**4,850**	**4,994**

Note: Totals may not sum due to independent rounding.

Uncertainty and Time-Series Consistency

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.[107] 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.

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

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

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 2006 IPCC Guidelines is to use data by specific aircraft type, number of individual flights and, ideally, movement data to better differentiate between domestic and international aviation and to facilitate estimating the effects of changes in technologies. 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 near-ground level emissions of gases other than CO_2.[108]

There is also concern regarding the reliability of the existing DOC (2011) data on marine vessel fuel consumption reported at U.S. customs stations due to the significant degree of inter-annual variation.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

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

Slight changes to emission estimates are due to revisions made to historical activity data for aviation jet fuel consumption using the FAA's AEDT. These historical data changes resulted in changes to the emission estimates for 1990 through 2009 relative to the previous inventory, which averaged to an annual decrease in emissions from international bunker fuels of 0.03 Tg CO_2 Eq. (less than 0.1 percent) in CO_2 emissions, an annual decrease of less than 0.01 Tg CO_2 Eq. (0.01 percent) in CH_4 emissions, and an annual decrease of less than 0.01 Tg CO_2 Eq. (0.01 percent) in N_2O emissions.

3.10. 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 in addition to CH_4 and N_2O already covered in this chapter. In line with the reporting requirements for inventories submitted under the UNFCCC, CO_2 emissions from biomass combustion have been estimated separately from fossil fuel CO_2 emissions and are not directly included in the energy sector contributions to U.S. totals. In accordance with IPCC methodological guidelines, any such emissions are calculated by accounting for net carbon (C) fluxes from changes in biogenic C reservoirs in wooded or crop lands. For a more

[108] 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.

complete description of this methodological approach, see the *Land Use, Land-Use Change, and Forestry* chapter (Chapter 7), which accounts for the contribution of any resulting CO_2 emissions to U.S. totals within the Land Use, Land-Use Change and Forestry sector's approach.

In 2010, total CO_2 emissions from the burning of woody biomass in the industrial, residential, commercial, and electricity generation sectors were approximately 191.6 Tg CO_2 Eq. (191,591 Gg) (see Table 3-54 and Table 3-55). As the largest consumer of woody biomass, the industrial sector was responsible for 70 percent of the CO_2 emissions from this source. Emissions from this sector increased from 2009 to 2010 due to a corresponding increase in wood consumption. The residential sector was the second largest emitter, constituting 25 percent of the total, while the commercial and electricity generation sectors accounted for the remainder.

Table 3-54: CO_2 Emissions from Wood Consumption by End-Use Sector (Tg CO_2 Eq.)

End-Use Sector	1990		2005	2006	2007	2008	2009	2010
Industrial	143.2		148.4	150.0	143.9	136.3	122.9	133.9
Residential	63.3		48.3	43.7	48.1	50.1	48.4	47.3
Commercial	7.2		7.8	7.2	7.8	8.1	8.2	7.9
Electricity Generation	0.7		1.2	1.7	2.4	2.8	2.4	2.6
Total	**214.4**		**205.7**	**202.7**	**202.2**	**197.4**	**181.8**	**191.6**

Note: Totals may not sum due to independent rounding.

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

End-Use Sector	1990		2005	2006	2007	2008	2009	2010
Industrial	143,219		148,386	150,033	143,929	136,324	122,851	133,871
Residential	63,286		48,283	43,657	48,113	50,147	48,440	47,260
Commercial	7,173		7,821	7,246	7,768	8,133	8,160	7,908
Electricity Generation	733		1,182	1,744	2,394	2,754	2,355	2,552
Total	**214,410**		**205,671**	**202,680**	**202,204**	**197,358**	**181,806**	**191,591**

Note: Totals may not sum due to independent rounding.

Biomass-derived fuel consumption in the United States transportation sector consisted primarily of ethanol use. 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.

In 2010, the United States consumed an estimated 1,089 trillion Btu of ethanol, and as a result, produced approximately 74.5 Tg CO_2 Eq. (74,519 Gg) (see Table 3-56 and Table 3-57) 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 3-56: CO_2 Emissions from Ethanol Consumption (Tg CO_2 Eq.)

End-Use Sector	1990		2005	2006	2007	2008	2009	2010
Transportation	4.1		22.4	30.2	38.1	53.8	61.2	73.2
Industrial	0.1		0.5	0.7	0.7	0.8	0.9	1.1
Commercial	+		0.1	0.1	0.1	0.1	0.2	0.2
Total	**4.2**		**22.9**	**31.0**	**38.9**	**54.7**	**62.3**	**74.5**

+ Does not exceed 0.05 Tg CO_2 Eq.

Table 3-57: CO_2 Emissions from Ethanol Consumption (Gg)

End-Use Sector	1990		2005	2006	2007	2008	2009	2010
Transportation[a]	4,136		22,414	30,237	38,116	53,796	61,191	73,225
Industrial	56		468	662	674	797	888	1,062
Commercial	34		60	86	135	146	194	232

Total	**4,227**	**22,943**	**30,985**	**38,924**	**54,739**	**62,272**	**74,519**

[a] See Annex 3.2, Table A-88 for additional information on transportation consumption of these fuels.

Methodology

Woody biomass emissions were estimated by applying two EIA gross heat contents (Lindstrom 2006) to U.S. consumption data (see Table 3-58), provided in energy units. This year woody biomass consumption data for the industrial, residential, and commercial sectors were obtained from EIA 2011, while woody biomass consumption data for the electricity generation sector was estimated from EPA's Clean Air Market Acid Rain Program dataset (EPA 2011). The bottom-up analysis of woody biomass consumption based on EPA's Acid Rain Program dataset indicated that the amount of woody biomass consumption allocated in the EIA statistics should be adjusted. Therefore, for these estimates, the electricity generation sector's woody biomass consumption was adjusted downward to match the value obtained from the bottom-up analysis based on EPA's Acid Rain Program dataset. As the total woody biomass consumption estimate from EIA is considered to be accurate at the national level, the woody biomass consumption totals for the industrial, residential, and commercial sectors were adjusted upward proportionately.

One heat content (16.95 MMBtu/MT wood and wood waste) was applied to the industrial sector's consumption, while the other heat content (15.43 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 emission factor of 18.67 Tg C/QBtu (EPA 2010) to U.S. ethanol consumption estimates that were provided in energy units (EIA 2011) (see Table 3-59).

Table 3-58: Woody Biomass Consumption by Sector (Trillion Btu)

End-Use Sector	1990	2005	2006	2007	2008	2009	2010
Industrial	1,525.8	1,580.8	1,598.4	1,533.3	1,452.3	1,308.8	1,426.2
Residential	613.7	468.2	423.4	466.6	486.3	469.8	458.3
Commercial	69.6	75.8	70.3	75.3	78.9	79.1	76.7
Electricity Generation	7.1	11.5	16.9	23.2	26.7	22.8	24.7
Total	**2,216.2**	**2,136.4**	**2,108.9**	**2,098.5**	**2,044.2**	**1,880.5**	**1,985.9**

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

End-Use Sector	1990	2005	2006	2007	2008	2009	2010
Transportation	60.4	327.4	441.7	556.8	785.8	893.9	1,069.7
Industrial	0.8	6.8	9.7	9.8	11.6	13.0	15.5
Commercial	0.5	0.9	1.3	2.0	2.1	2.8	3.4
Total	**61.7**	**335.1**	**452.6**	**568.6**	**799.6**	**909.7**	**1,088.6**

Uncertainty and Time-Series Consistency

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 decrease 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.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section,

above.

Recalculations Discussion

Wood and ethanol consumption values were revised relative to the previous Inventory for 2009 based on updated information from EIA's Annual Energy Review (EIA 2011). Additionally, the change in methodology for calculating emissions from woody biomass led a decrease in emissions from the electricity generation sector and an increase in emissions for the other sectors over the time series. This adjustment of historical data for wood biomass consumption resulted in an average annual decrease in emissions from wood biomass consumption of about 1.0 Tg CO_2 Eq. (0.5 percent) from 1990 through 2009. Slight adjustments were made to ethanol consumption based on updated information from EIA (2011), which slightly increased estimates for ethanol consumed. As a result of adjustments to historical EIA data, average annual emissions from ethanol consumption increased by less than 0.05 Tg CO_2 Eq. (less than 0.05 percent) relative to the previous Inventory.

Planned Improvements

The availability of facility-level combustion emissions through EPA's GHGRP will be examined to help better characterize the industrial sector's energy consumption in the United States, and further classify business establishments according to industrial economic activity type. Most methodologies used in EPA's GHGRP are consistent with IPCC, though for EPA's GHGRP, facilities collect detailed information specific to their operations according to detailed measurement standards, which may differ with the more aggregated data collected for the Inventory to estimate total, national U.S. emissions. In addition, and unlike the reporting requirements for this chapter under the UNFCCC reporting guidelines,[109] some facility-level fuel combustion emissions reported under the GHGRP may also include industrial process emissions. In line with UNFCCC reporting guidelines, fuel combustion emissions are included in this chapter, while process emissions are included in the Industrial Processes chapter of this report. In examining data from EPA's GHGRP that would be useful to improve the emission estimates for the CO_2 from biomass combustion category, particular attention will also be made to ensure time series consistency, as the facility-level reporting data from EPA's GHGRP are not available for all inventory years as reported in this inventory. Additionally, analyses will focus on aligning reported facility-level fuel types and IPCC fuel types per the national energy statistics, ensuring CO_2 emissions from biomass are separated in the facility-level reported data, and maintaining consistency with national energy statistics provided by EIA. In implementing improvements and integration of data from EPA's GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will be relied upon.[110]

[109] See <http://unfccc.int/resource/docs/2006/sbsta/eng/09.pdf>

[110] See <http://www.ipcc-nggip.iges.or.jp/meeting/pdfiles/1008_Model_and_Facility_Level_Data_Report.pdf>

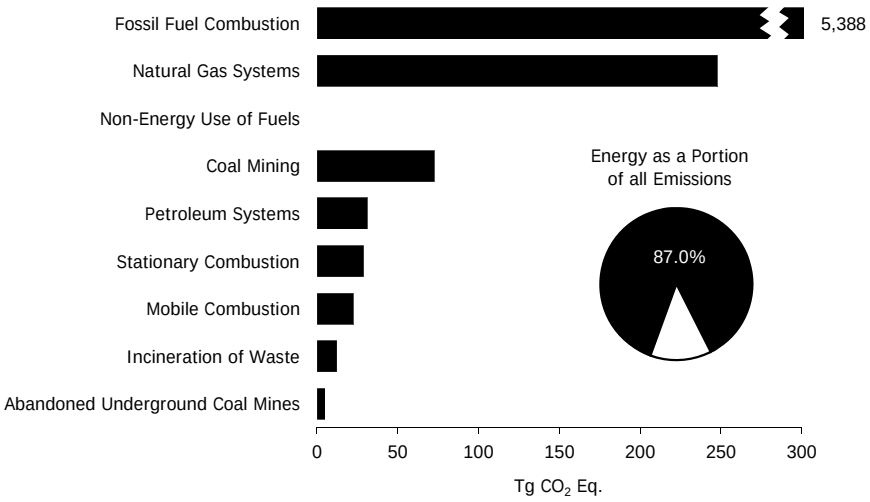

Figure 3-1: 2010 Energy Chapter Greenhouse Gas Sources

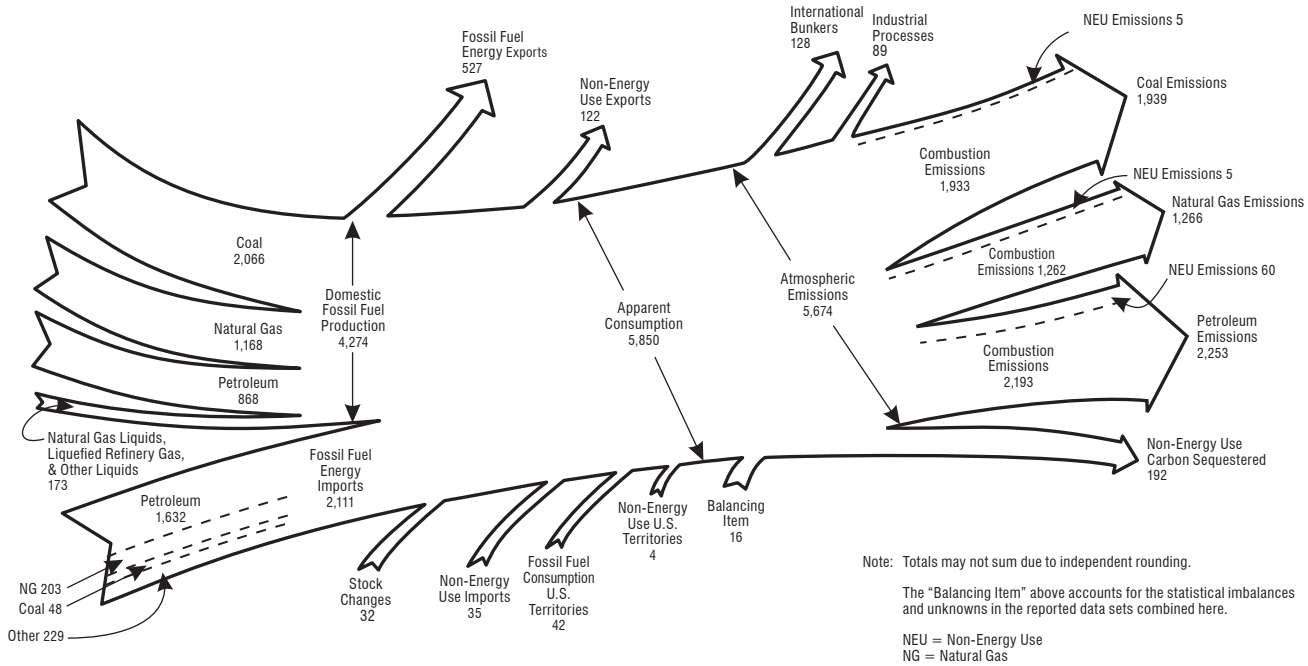

Figure 3-2 2010 U.S. Fossil Carbon Flows (Tg CO_2 Eq.)

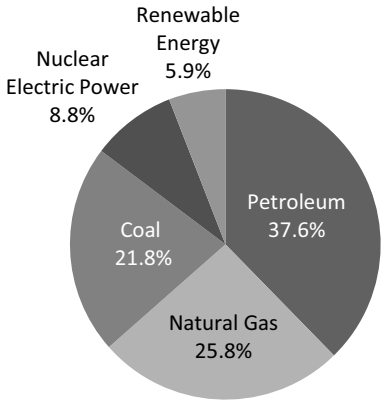

Figure 3-3: 2010 U.S. Energy Consumption by Energy Source

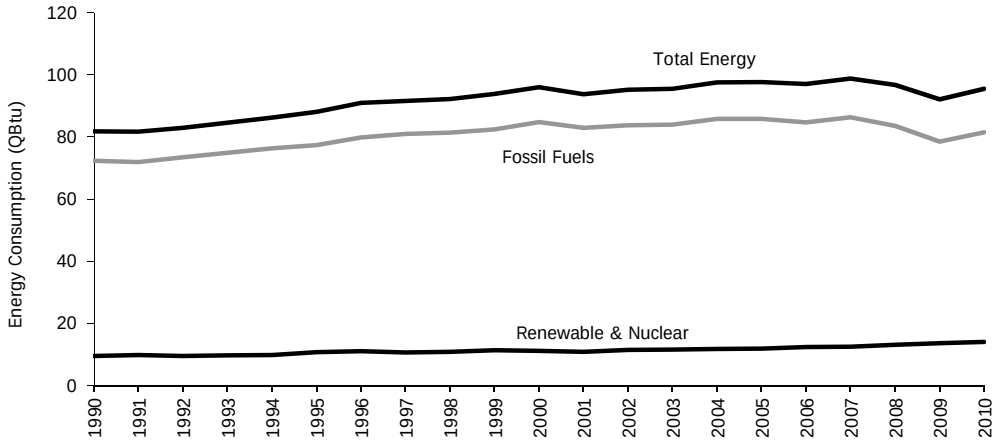

Figure 3-4: U.S. Energy Consumption (Quadrillion Btu)

Note: Expressed as gross calorific values.

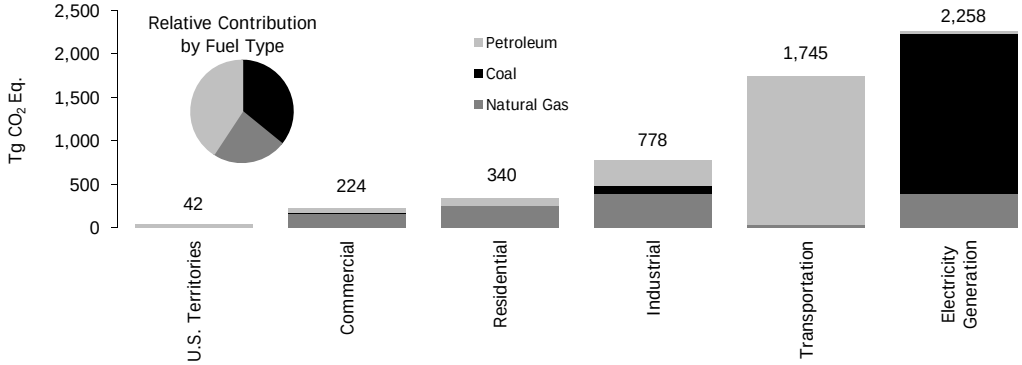

Figure 3-5: 2010 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type

Note: The electricity generation sector also includes emissions of less than 0.5 Tg CO_2 Eq. from geothermal-based electricity generation.

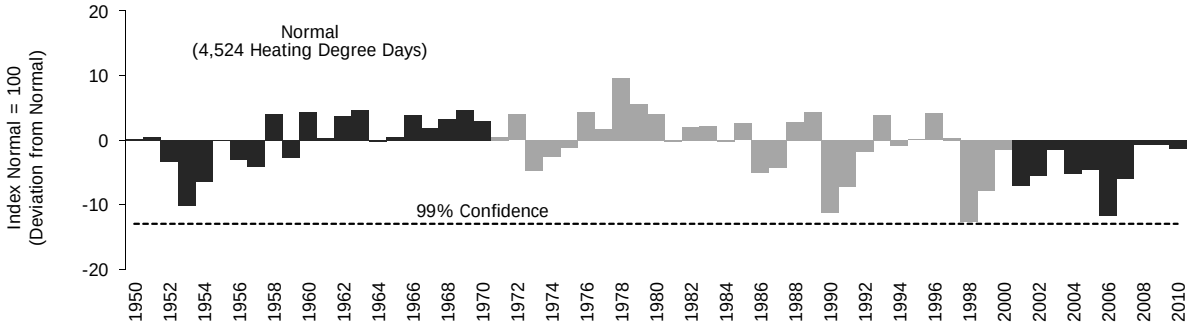

Figure 3-6: Annual Deviations from Normal Heating Degree Days for the United States (1950-2010)
Note: Climatological normal data are highlighted.
Statistical confidence interval for "normal" climatology period of 1971 through 2000.

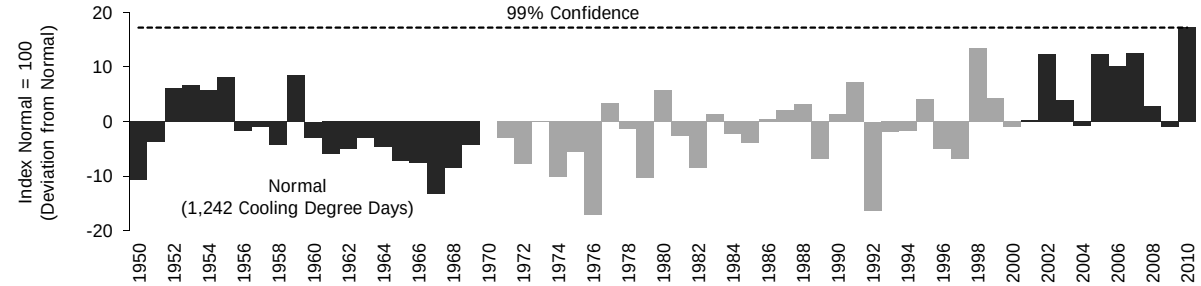

Figure 3-7: Annual Deviations from Normal Cooling Degree Days for the United States (1950-2010)
Note: Climatological normal data are highlighted.
Statistical confidence interval for "normal" climatology period of 1971 through 2000.

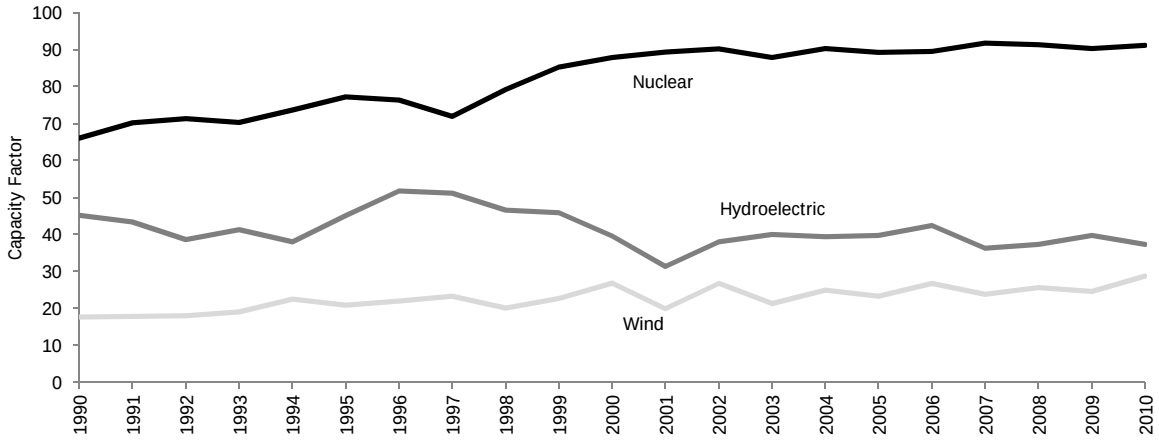

Figure 3-8: Nuclear, Hydroelectric, and Wind Power Plant Capacity Factors in the United States (1990-2010)

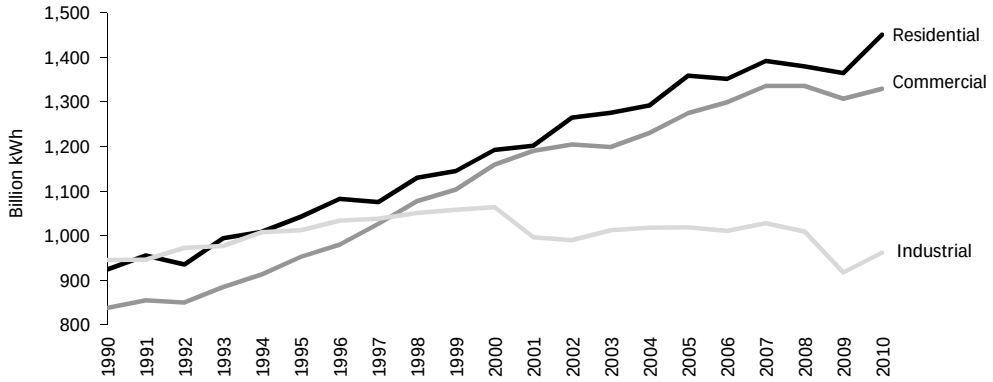

Figure 3-9: Electric Generation Retail Sales by End-Use Sector
Note: The transportation end-use sector consumes minor quanties of electricity.

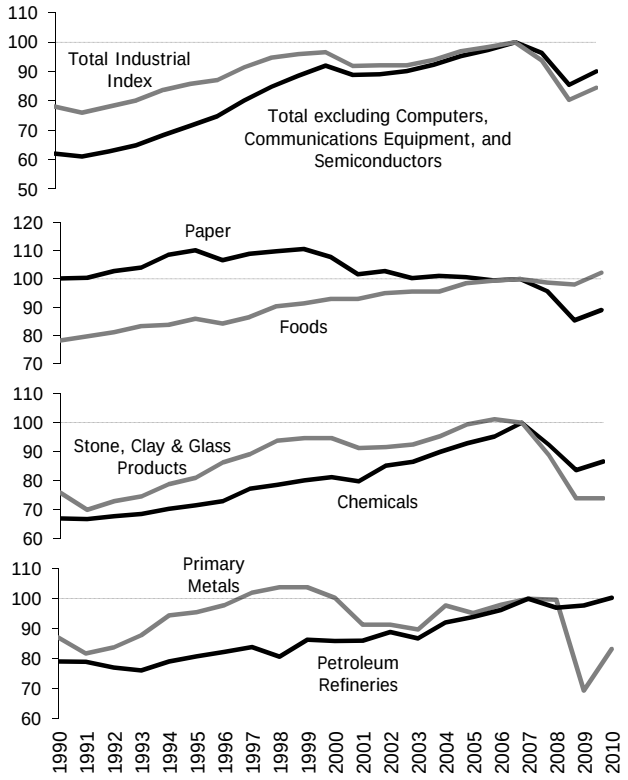

Figure 3-10: Industrial Production Indexes (Index 2007=100)

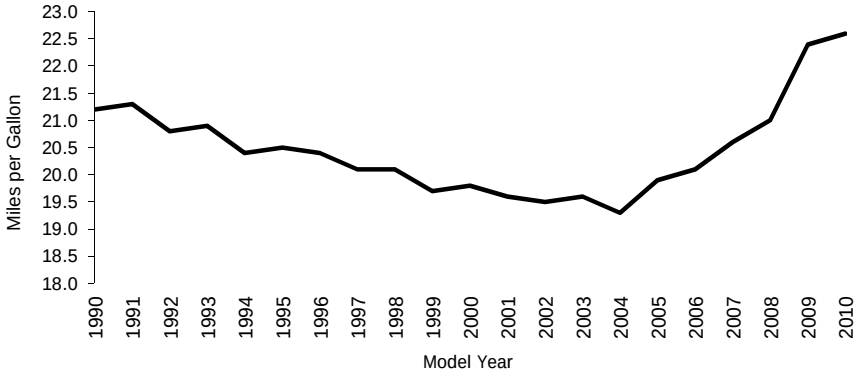

Figure 3-11: Sales-Weighted Fuel Economy of New Passenger Cars and Light-Duty Trucks, 1990-2010

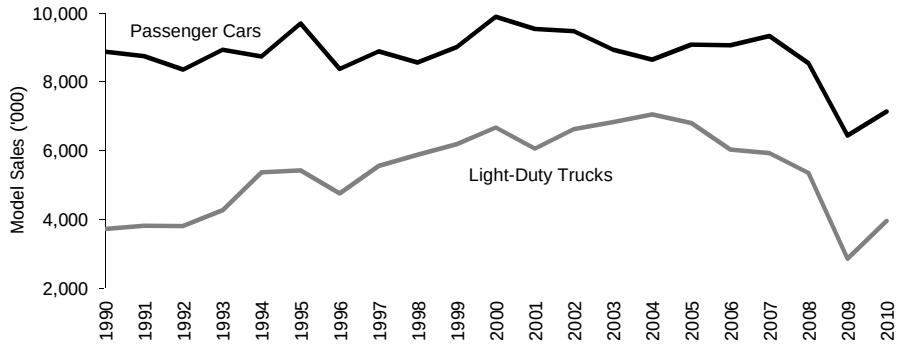

Figure 3-12: Sales of New Passenger Cars and Light-Duty Trucks, 1990-2010

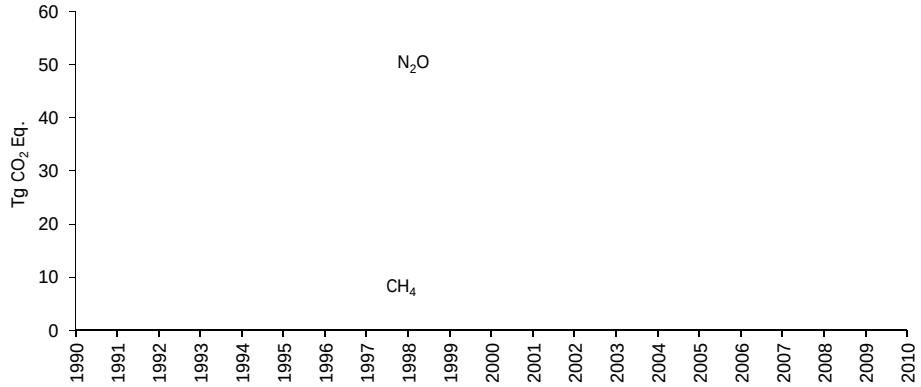

Figure 3-13: Mobile Source CH_4 and N_2O Emissions

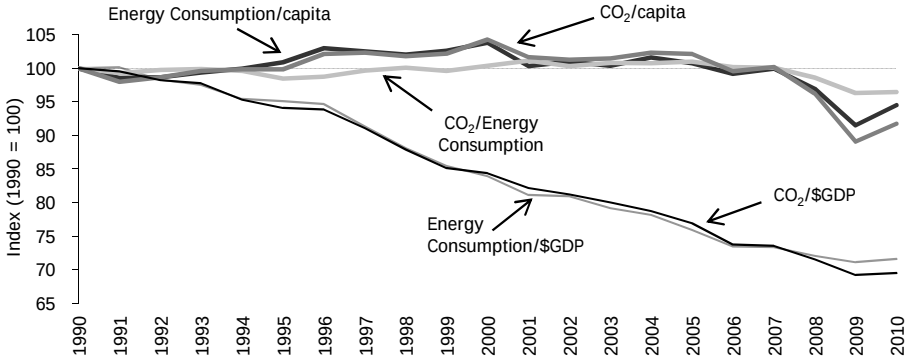

Figure 3-14: U.S. Energy Consumption and Energy-Related CO_2 Emissions Per Capita and Per Dollar GDP