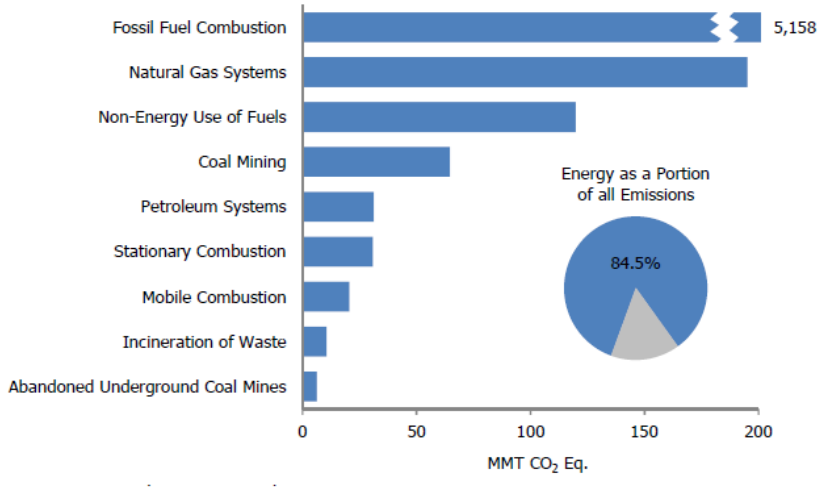
3. Energy

Energy-related activities were the primary sources of U.S. anthropogenic greenhouse gas emissions, accounting for 84.5 percent of total greenhouse gas emissions on a carbon dioxide (CO_2) equivalent basis in 2013.[1] This included 97, 41, and 12 percent of the nation's CO_2, methane (CH_4), and nitrous oxide (N_2O) emissions, respectively. Energy-related CO_2 emissions alone constituted 79.9 percent of national emissions from all sources on a CO_2 equivalent basis, while the non-CO_2 emissions from energy-related activities represented a much smaller portion of total national emissions (4.6 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 32,310 MMT of CO_2 were added to the atmosphere through the combustion of fossil fuels in 2012, of which the United States accounted for approximately 16 percent.[2] 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: 2013 Energy Chapter Greenhouse Gas Sources

Note: Emissions values are presented in CO_2 equivalent mass units using IPCC AR4 GWP values.

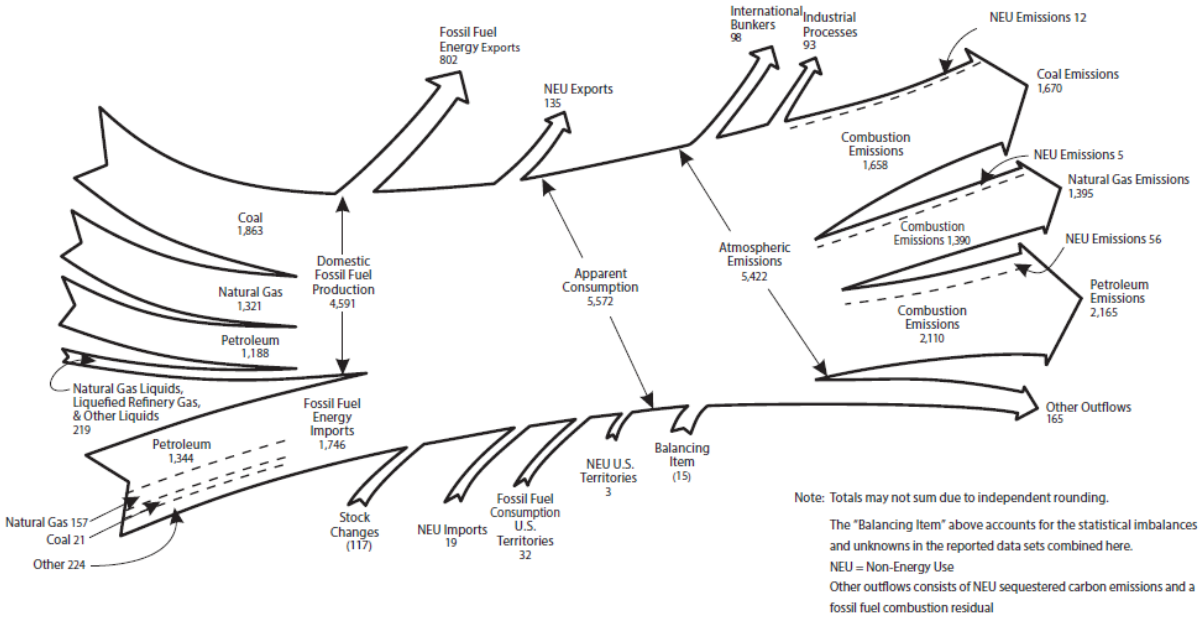


[1] Estimates are presented in units of million metric tons of carbon dioxide equivalent (MMT CO_2 Eq.), which weight each gas by its global warming potential, or GWP, value. See section on global warming potentials in the Executive Summary.

[2] Global CO_2 emissions from fossil fuel combustion were taken from Energy Information Administration *International Energy Statistics 2013* <http://tonto.eia.doe.gov/cfapps/ipdbproject/IEDIndex3.cfm> EIA (2013).

Figure 3-2: 2013 U.S. Fossil Carbon Flows (MMT CO_2 Eq.)

Note: Emissions values are presented in CO_2 equivalent mass units using IPCC AR4 GWP values.



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 million metric tons of CO_2 equivalents (MMT CO_2 Eq.), while unweighted gas emissions in kilotons (kt) are provided in Table 3-2. Overall, emissions due to energy-related activities were 5,636.6 MMT CO_2 Eq. in 2013,[3] an increase of 6.5 percent since 1990.

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

Gas/Source	1990	2005	2009	2010	2011	2012	2013
CO_2	**4,908.4**	**5,933.9**	**5,351.2**	**5,529.2**	**5,390.3**	**5,181.1**	**5,331.5**
Fossil Fuel Combustion	4,740.7	5,747.7	5,197.1	5,367.1	5,231.3	5,026.0	5,157.7
Electricity Generation	1,820.8	2,400.9	2,145.7	2,258.4	2,157.7	2,022.2	2,039.8
Transportation	1,493.8	1,887.8	1,720.3	1,732.0	1,711.5	1,700.8	1,718.4
Industrial	842.5	827.8	727.7	775.7	774.1	784.2	817.3
Residential	338.3	357.8	336.4	334.7	327.2	283.1	329.6
Commercial	217.4	223.5	223.5	220.2	221.0	197.1	220.7
U.S. Territories	27.9	49.9	43.5	46.2	39.8	38.6	32.0
Non-Energy Use of Fuels	117.7	138.9	106.0	114.6	108.4	104.9	119.8
Natural Gas Systems	37.6	30.0	32.2	32.3	35.6	34.8	37.8
Incineration of Waste	8.0	12.5	11.3	11.0	10.5	10.4	10.1
Petroleum Systems	4.4	4.9	4.7	4.2	4.5	5.1	6.0
Biomass – Wood[a]	*215.2*	*206.9*	*188.2*	*192.5*	*195.2*	*194.9*	*208.6*
International Bunker Fuels[a]	*103.5*	*113.1*	*106.4*	*117.0*	*111.7*	*105.8*	*99.8*
Biomass – Ethanol[a]	*4.2*	*22.9*	*62.3*	*72.6*	*72.9*	*72.8*	*74.7*
CH_4	**328.5**	**280.9**	**285.5**	**279.2**	**268.2**	**259.2**	**263.5**
Natural Gas Systems	179.1	176.3	168.0	159.6	159.3	154.4	157.4
Coal Mining	96.5	64.1	79.9	82.3	71.2	66.5	64.6

[3] Following the revised reporting requirements under the UNFCCC, this Inventory report presents CO_2 equivalent values based on the *IPCC Fourth Assessment Report* (AR4) GWP values. See the Introduction chapter for more information.

Petroleum Systems	31.5	23.5	21.5	21.3	22.0	23.3	25.2
Stationary Combustion	8.5	7.4	7.4	7.1	7.1	6.6	8.0
Abandoned Underground Coal Mines	7.2	6.6	6.4	6.6	6.4	6.2	6.2
Mobile Combustion	5.6	3.0	2.3	2.3	2.3	2.2	2.1
Incineration of Waste	+	+	+	+	+	+	+
International Bunker Fuels[a]	*0.2*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*
N_2O	**53.6**	**58.7**	**45.3**	**46.2**	**44.1**	**41.9**	**41.6**
Stationary Combustion	11.9	20.2	20.4	22.2	21.3	21.4	22.9
Mobile Combustion	41.2	38.1	24.6	23.7	22.5	20.2	18.4
Incineration of Waste	0.5	0.4	0.3	0.3	0.3	0.3	0.3
International Bunker Fuels[a]	*0.9*	*1.0*	*0.9*	*1.0*	*1.0*	*0.9*	*0.9*
Total	**5,290.5**	**6,273.6**	**5,682.1**	**5,854.6**	**5,702.6**	**5,482.2**	**5,636.6**

Note: Emissions values are presented in CO_2 equivalent mass units using IPCC AR4 GWP values.
+ Does not exceed 0.05 MMT CO_2 Eq.
[a] 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 (kt)

Gas/Source	1990	2005	2009	2010	2011	2012	2013
CO_2	**4,908,390**	**5,933,912**	**5,351,228**	**5,529,210**	**5,390,268**	**5,181,104**	**5,331,493**
Fossil Fuel Combustion	4,740,670	5,747,683	5,197,058	5,367,144	5,231,341	5,026,000	5,157,697
Non-Energy Use of Fuels	117,658	138,877	106,018	114,554	108,359	104,917	119,850
Natural Gas Systems	37,645	29,995	32,201	32,334	35,551	34,764	37,808
Incineration of Waste	7,972	12,454	11,295	11,026	10,550	10,363	10,137
Petroleum Systems	4,445	4,904	4,656	4,153	4,467	5,060	6,001
Biomass –Wood[a]	*215,186*	*206,901*	*188,220*	*192,462*	*195,182*	*194,903*	*208,594*
International Bunker Fuels[a]	*103,463*	*113,139*	*106,410*	*116,992*	*111,660*	*105,805*	*99,763*
Biomass – Ethanol[a]	*4,227*	*22,943*	*62,272*	*72,647*	*72,881*	*72,827*	*74,743*
CH_4	**13,139**	**11,237**	**11,419**	**11,168**	**10,729**	**10,366**	**10,541**
Natural Gas Systems	7,165	7,053	6,722	6,382	6,371	6,176	6,295
Coal Mining	3,860	2,565	3,194	3,293	2,849	2,658	2,584
Petroleum Systems	1,261	939	860	854	878	931	1,009
Stationary Combustion	339	296	295	283	283	264	318
Abandoned Underground Coal Mines	288	264	254	263	257	249	249
Mobile Combustion	225	121	93	92	91	88	86
Incineration of Waste	+	+	+	+	+	+	+
International Bunker Fuels[a]	*7*	*5*	*5*	*6*	*5*	*4*	*3*
N_2O	**180**	**197**	**152**	**155**	**148**	**141**	**140**
Stationary Combustion	40	68	69	74	71	72	77
Mobile Combustion	138	128	82	80	76	68	62
Incineration of Waste	2	1	1	1	1	1	1
International Bunker Fuels[a]	*3*	*3*	*3*	*3*	*3*	*3*	*3*

+ Does not exceed 0.5 kt
[a] 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.

Box 3-1: Methodological Approach for Estimating and Reporting U.S. Emissions and Sinks

In following the UNFCCC requirement under Article 4.1 to develop and submit national greenhouse gas emission inventories, the emissions and sinks presented in this report and this chapter, are organized by source and sink categories and calculated using internationally-accepted methods provided by the Intergovernmental Panel on Climate Change (IPCC). Additionally, the calculated emissions and sinks in a given year for the United States are presented in a common manner in line with the UNFCCC reporting guidelines for the reporting of inventories under this international agreement. The use of consistent methods to calculate emissions and sinks by all nations

providing their inventories to the UNFCCC ensures that these reports are comparable. In this regard, U.S. emissions and sinks reported in this Inventory report are comparable to emissions and sinks reported by other countries. Emissions and sinks provided in this Inventory do not preclude alternative examinations, but rather, this Inventory presents emissions and sinks in a common format consistent with how countries are to report Inventories under the UNFCCC. The report itself, and this chapter, follows this standardized format, and provides an explanation of the IPCC methods used to calculate emissions and sinks, and the manner in which those calculations are conducted.

Box 3-2: 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. Data reporting by affected facilities included the reporting of emissions from fuel combustion at that affected facility. In general, the threshold for reporting is 25,000 metric tons or more of CO_2 Eq. per year.

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 (see, also, Box 3-4). 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. It should be noted that the definitions and provisions for reporting fuel types in EPA's 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 EPA's GHGRP and specific data caveats associated with monitoring methods in EPA's GHGRP has been provided on the GHGRP website.

EPA presents the data collected by its 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.

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 (MMT CO_2 Eq.)

Gas	1990	2005	2009	2010	2011	2012	2013
CO_2	4,740.7	5,747.7	5,197.1	5,367.1	5,231.3	5,026.0	5,157.7
CH_4	14.1	10.4	9.7	9.4	9.3	8.8	10.1
N_2O	53.1	58.4	45.0	45.9	43.8	41.6	41.3
Total	**4,807.9**	**5,816.5**	**5,251.8**	**5,422.5**	**5,284.5**	**5,076.4**	**5,209.1**

Note: Emissions values are presented in CO_2 equivalent mass units using IPCC AR4 GWP values.

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

Gas	1990	2005	2009	2010	2011	2012	2013
CO_2	4,740,670	5,747,683	5,197,058	5,367,144	5,231,341	5,026,000	5,157,697
CH_4	565	416	389	375	374	352	404
N_2O	178	196	151	154	147	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 2013, CO_2 emissions from fossil fuel combustion increased by 2.6 percent relative to the previous year. The increase in CO_2 emissions from fossil fuel combustion was a result of multiple factors, including: (1) an increase in the price of natural gas leading to increased coal-fired generation in the electric power sector; (2) much colder winter conditions resulting in an increased demand for heating fuel in the residential and commercial sectors; (3) an increase in industrial production across multiple sectors resulting in increases in industrial sector emissions;[4] and (4) an increase in transportation emissions resulting from an increase in vehicle miles traveled (VMT) and fuel use across on-road transportation modes. In 2013, CO_2 emissions from fossil fuel combustion were 5,157.7 MMT CO_2 Eq., or 8.8 percent above emissions in 1990 (see Table 3-5).[5]

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

Fuel/Sector	1990	2005	2009	2010	2011	2012	2013
Coal	**1,718.4**	**2,112.3**	**1,834.2**	**1,927.7**	**1,813.9**	**1,592.8**	**1,658.1**
Residential	3.0	0.8	0.0	0.0	0.0	0.0	0.0
Commercial	12.0	9.3	6.9	6.6	5.8	4.1	3.9
Industrial	155.3	115.3	83.0	90.1	82.0	74.1	75.8
Transportation	NE	NE	NE	NE	NE	NE	NE
Electricity Generation	1,547.6	1,983.8	1,740.9	1,827.6	1,722.7	1,511.2	1,575.0
U.S. Territories	0.6	3.0	3.4	3.4	3.4	3.4	3.4
Natural Gas	**1,000.3**	**1,166.7**	**1,216.9**	**1,272.1**	**1,291.5**	**1,352.6**	**1,389.5**
Residential	238.0	262.2	258.8	258.6	254.7	224.8	267.1
Commercial	142.1	162.9	168.9	167.7	170.5	156.9	178.2
Industrial	408.9	388.5	377.6	407.2	417.3	434.8	450.8
Transportation	36.0	33.1	37.9	38.1	38.9	41.3	48.8
Electricity Generation	175.3	318.8	372.2	399.0	408.8	492.2	441.9
U.S. Territories	NO	1.3	1.5	1.5	1.4	2.6	2.6
Petroleum	**2,021.5**	**2,468.4**	**2,145.5**	**2,167.0**	**2,125.5**	**2,080.2**	**2,109.6**

[4] Further details on industrial sector combustion emissions are provided by EPA's GHGRP (http://ghgdata.epa.gov/ghgp/main.do).

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

Residential	97.4	94.9	77.6	76.2	72.6	58.3	62.5
Commercial	63.3	51.3	47.7	45.9	44.7	36.1	38.6
Industrial	278.3	324.0	267.0	278.4	274.8	275.4	290.6
Transportation	1,457.7	1,854.7	1,682.4	1,693.9	1,672.7	1,659.5	1,669.6
Electricity Generation	97.5	97.9	32.2	31.4	25.8	18.3	22.4
U.S. Territories	27.2	45.6	38.6	41.3	34.9	32.6	26.0
Geothermal[a]	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**
Total	**4,740.7**	**5,747.7**	**5,197.1**	**5,367.1**	**5,231.3**	**5,026.0**	**5,157.7**

+ Does not exceed 0.05 MMT CO_2 Eq.
NE (Not estimated)
NO (Not occurring)
[a] Although not technically a fossil fuel, geothermal energy-related CO_2 emissions are included for reporting purposes.
Note: Totals may not sum due to independent rounding.

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

Longer-term changes in energy consumption patterns, however, tend to be more a function of aggregate societal trends that affect the scale of consumption (e.g., population, number of cars, 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.[6] 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 2013 Emissions from Fossil Fuel Combustion for Selected Fuels and Sectors (MMT CO_2 Eq. and Percent)

Sector	Fuel Type	2009 to 2010		2010 to 2011		2011 to 2012		2012 to 2013		Total 2013
Electricity Generation	Coal	86.7	5.0%	-104.9	-5.7%	-211.5	-12.3%	63.8	4.2%	1,575.0
Electricity Generation	Natural Gas	26.8	7.2%	9.8	2.5%	83.5	20.4%	-50.3	-10.2%	441.9
Electricity Generation	Petroleum	-0.8	-2.4%	-5.6	-17.8%	-7.5	-29.0%	4.1	22.2%	22.4
Transportation[a]	Petroleum	11.4	0.7%	-21.2	-1.3%	-13.2	-0.8%	10.2	0.6%	1,669.6
Residential	Natural Gas	-0.3	-0.1%	-3.9	-1.5%	-29.8	-11.7%	42.3	18.8%	267.1
Commercial	Natural Gas	-1.2	-0.7%	2.7	1.6%	-13.6	-8.0%	21.4	13.6%	178.2
Industrial	Coal	7.0	8.5%	-8.1	-9.0%	-7.9	-9.7%	1.8	2.4%	75.8
Industrial	Natural Gas	29.6	7.8%	10.1	2.5%	17.5	4.2%	16.0	3.7%	450.8
All Sectors[b]	**All Fuels[b]**	**170.1**	**3.3%**	**-135.8**	**-2.5%**	**-205.3**	**-3.9%**	**131.7**	**2.6%**	**5,157.7**

Note: Emissions values are presented in CO_2 equivalent mass units using IPCC AR4 GWP values.
[a] Excludes emissions from International Bunker Fuels.
[b] Includes fuels and sectors not shown in table.

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

In the United States, 82 percent of the energy consumed in 2013 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 (10 percent), primarily hydroelectric power, wind energy and biofuels (EIA 2015).[7] Specifically, petroleum supplied the largest share of domestic energy demands, accounting for 36 percent of total U.S. energy consumption in 2013. Natural gas and coal followed in order of energy demand importance, accounting for approximately 28 percent and 19 percent of total U.S. energy 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 2015).

Figure 3-3: 2013 U.S. Energy Consumption by Energy Source (percent)

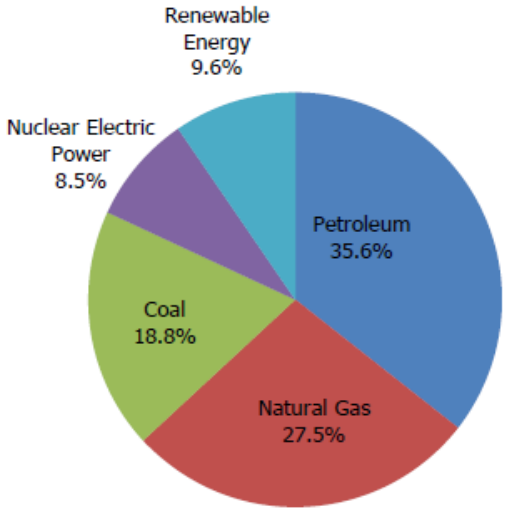
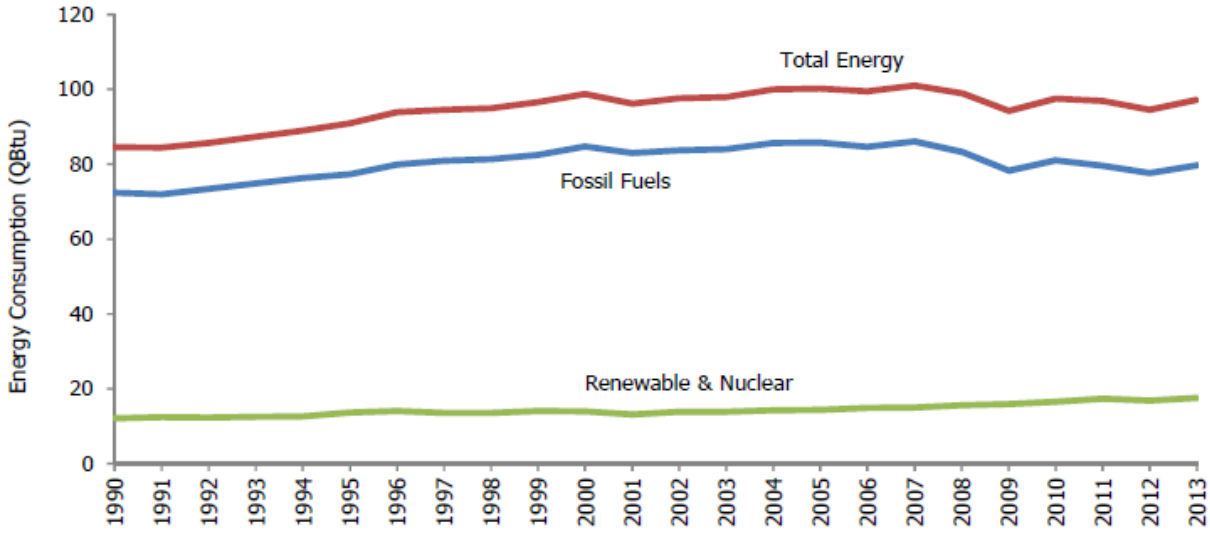
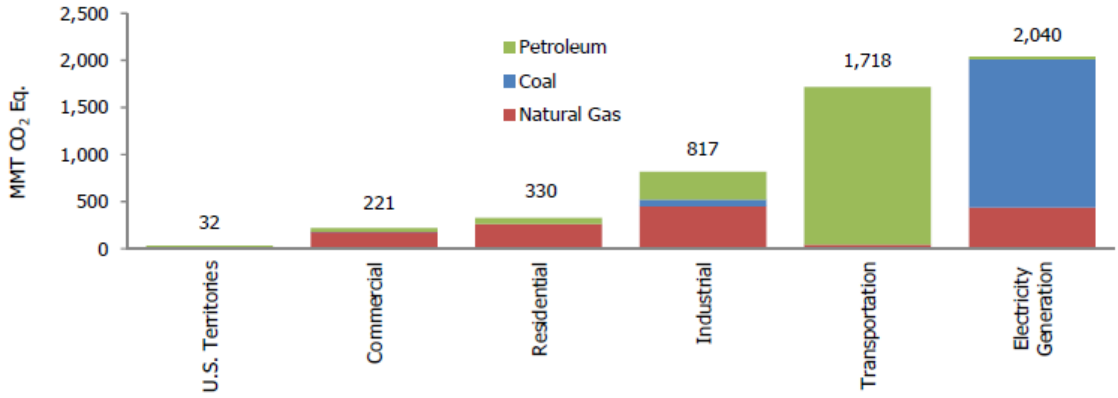


Figure 3-4: U.S. Energy Consumption (Quadrillion Btu)



[7] Renewable energy, as defined in EIA's energy statistics, includes the following energy sources: hydroelectric power, geothermal energy, biofuels, solar energy, and wind energy.

Figure 3-5: 2013 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type (MMT CO_2 Eq.)



Fossil fuels are generally combusted for the purpose of producing energy for useful heat and work. During the combustion process, the C stored in the fuels is oxidized and emitted as CO_2 and smaller amounts of other gases, including CH_4, CO, and NMVOCs.[8] 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 all of the C in fossil fuels used to produce energy is eventually converted to atmospheric CO_2.

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

In 2013, weather conditions, and a very cold first quarter of the year in particular, caused a significant increase in energy demand for heating fuels and is reflected in the increased residential emissions during the early part of the year (EIA 2015). The United States in 2013 also experienced a cooler winter overall compared to 2012, as heating degree days increased (18.5 percent). Cooling degree days decreased by 12.8 percent and despite this decrease in cooling degree days, electricity demand to cool homes still increased slightly. While colder winter conditions compared to 2012 resulted in a significant increase in the amount of energy required for heating, heating degree days in the United States were 1.2 percent below normal (see Figure 3-6). Summer conditions were slightly cooler in 2013 compared to 2012, and summer temperatures were warmer than normal, with cooling degree days 7.1 percent above normal (see Figure 3-7) (EIA 2015).[9]

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

[9] 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 effect 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).

Figure 3-6: Annual Deviations from Normal Heating Degree Days for the United States (1950–2013)

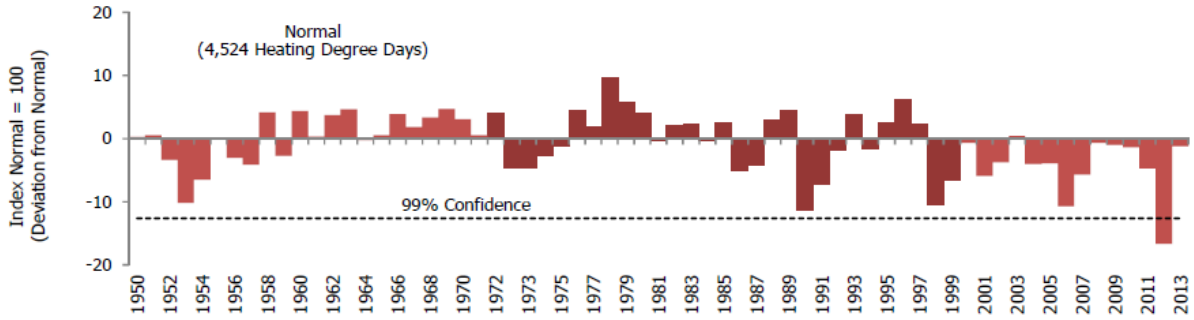
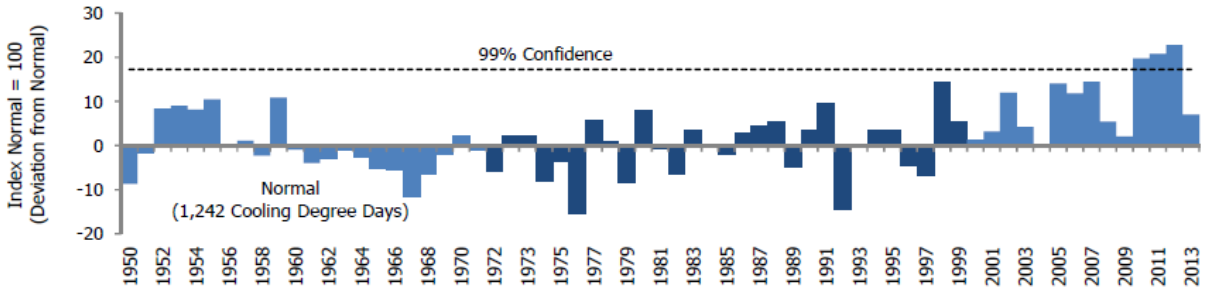


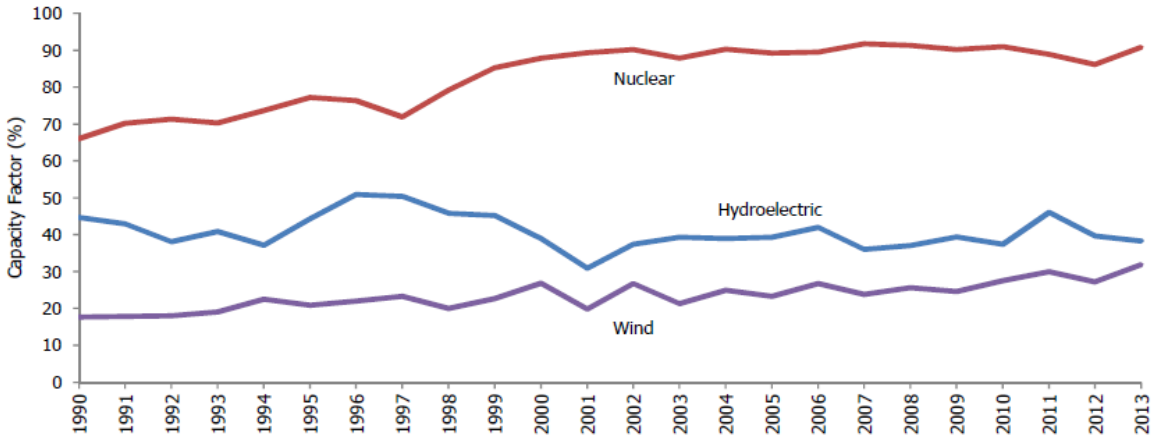
Figure 3-7: Annual Deviations from Normal Cooling Degree Days for the United States (1950–2013)



Although no new U.S. nuclear power plants have been constructed in recent years, the utilization (i.e., capacity factors)[10] of existing plants in 2013 remained high at 91 percent. Electricity output by hydroelectric power plants decreased in 2013 by approximately 3 percent. In recent years, the wind power sector has been showing strong growth, such that, on the margin, it is becoming a relatively important electricity source. Electricity generated by nuclear plants in 2013 provided nearly 3 times as much of the energy generated in the United States from hydroelectric plants (EIA 2015). Nuclear, hydroelectric, and wind power capacity factors since 1990 are shown in Figure 3-8.

[10] 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 (2015).

Figure 3-8: Nuclear, Hydroelectric, and Wind Power Plant Capacity Factors in the United States (1990–2013)



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.

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

End-Use Sector	1990	2005	2009	2010	2011	2012	2013
Electricity Generation	**1,828.5**	**2,417.4**	**2,162.9**	**2,277.4**	**2,175.8**	**2,040.4**	**2,059.3**
CO_2	1,820.8	2,400.9	2,145.7	2,258.4	2,157.7	2,022.2	2,039.8
CH_4	0.3	0.5	0.4	0.5	0.4	0.4	0.4
N_2O	7.4	16.0	16.8	18.5	17.6	17.8	19.1
Transportation	**1,540.6**	**1,928.9**	**1,747.2**	**1,758.0**	**1,736.3**	**1,723.2**	**1,739.0**
CO_2	1,493.8	1,887.8	1,720.3	1,732.0	1,711.5	1,700.8	1,718.4
CH_4	5.6	3.0	2.3	2.3	2.3	2.2	2.1
N_2O	41.2	38.1	24.6	23.7	22.5	20.2	18.4
Industrial	**847.4**	**832.4**	**731.4**	**779.6**	**778.0**	**788.2**	**821.2**
CO_2	842.5	827.8	727.7	775.7	774.1	784.2	817.3
CH_4	1.8	1.7	1.4	1.5	1.5	1.5	1.5
N_2O	3.1	2.9	2.3	2.5	2.4	2.4	2.4
Residential	**344.6**	**362.8**	**341.7**	**339.6**	**332.1**	**287.6**	**335.5**
CO_2	338.3	357.8	336.4	334.7	327.2	283.1	329.6
CH_4	5.2	4.1	4.4	4.0	4.0	3.7	5.0
N_2O	1.0	0.9	0.9	0.8	0.8	0.7	1.0
Commercial	**218.8**	**224.9**	**224.9**	**221.6**	**222.4**	**198.3**	**222.1**
CO_2	217.4	223.5	223.5	220.2	221.0	197.1	220.7
CH_4	1.0	1.1	1.1	1.1	1.0	0.9	1.0
N_2O	0.4	0.3	0.3	0.3	0.3	0.3	0.3
U.S. Territories[a]	**28.0**	**50.1**	**43.7**	**46.4**	**39.9**	**38.8**	**32.1**
Total	**4,807.9**	**5,816.5**	**5,251.8**	**5,422.5**	**5,284.5**	**5,076.4**	**5,209.1**

Note: Emissions values are presented in CO_2 equivalent mass units using IPCC AR4 GWP values.

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.

[a] 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.[11] 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. Carbon monoxide 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 from transportation.[12] 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 (MMT CO_2 Eq.)

End-Use Sector	1990	2005	2009	2010	2011	2012	2013
Transportation	**1,543.7**	**1,933.7**	**1,751.7**	**1,762.5**	**1,740.6**	**1,727.1**	**1,743.0**
CO_2	1,496.8	1,892.5	1,724.8	1,736.5	1,715.8	1,704.6	1,722.4
CH_4	5.6	3.0	2.3	2.3	2.3	2.2	2.1
N_2O	41.2	38.1	24.6	23.8	22.5	20.3	18.5
Industrial	**1,537.0**	**1,574.1**	**1,338.0**	**1,425.8**	**1,407.9**	**1,386.3**	**1,409.3**
CO_2	1,529.2	1,564.4	1,329.5	1,416.5	1,398.8	1,377.0	1,399.8
CH_4	2.0	1.9	1.5	1.6	1.6	1.6	1.6
N_2O	5.9	7.8	7.0	7.7	7.6	7.7	7.9
Residential	**940.2**	**1,224.9**	**1,134.3**	**1,186.7**	**1,129.4**	**1,019.4**	**1,083.3**
CO_2	931.4	1,214.1	1,122.6	1,174.8	1,117.9	1,008.4	1,070.2
CH_4	5.4	4.2	4.6	4.2	4.2	3.9	5.1
N_2O	3.4	6.6	7.1	7.7	7.3	7.1	7.9
Commercial	**759.1**	**1,033.7**	**984.2**	**1,001.0**	**966.6**	**904.9**	**941.5**

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

[12] 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.

CO_2	755.4	1,026.7	976.7	993.2	959.1	897.4	933.3
CH_4	1.1	1.2	1.2	1.2	1.2	1.1	1.2
N_2O	2.5	5.7	6.2	6.6	6.3	6.4	7.0
U.S. Territories[a]	**28.0**	**50.1**	**43.7**	**46.4**	**39.9**	**38.8**	**32.1**
Total	**4,807.9**	**5,816.5**	**5,251.8**	**5,422.5**	**5,284.5**	**5,076.4**	**5,209.1**

Note: Emissions values are presented in CO_2 equivalent mass units using IPCC AR4 GWP values.
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.
[a] 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 of 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.[13] 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 (MMT CO_2 Eq.)

Sector/Fuel Type	1990	2005	2009	2010	2011	2012	2013
Electricity Generation	**1,820.8**	**2,400.9**	**2,145.7**	**2,258.4**	**2,157.7**	**2,022.2**	**2,039.8**
Coal	1,547.6	1,983.8	1,740.9	1,827.6	1,722.7	1,511.2	1,575.0
Natural Gas	175.3	318.8	372.2	399.0	408.8	492.2	441.9
Fuel Oil	97.5	97.9	32.2	31.4	25.8	18.3	22.4
Geothermal	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Industrial	**842.5**	**827.8**	**727.7**	**775.7**	**774.1**	**784.2**	**817.3**
Coal	155.3	115.3	83.0	90.1	82.0	74.1	75.8
Natural Gas	408.9	388.5	377.6	407.2	417.3	434.8	450.8
Fuel Oil	278.3	324.0	267.0	278.4	274.8	275.4	290.6
Commercial	**217.4**	**223.5**	**223.5**	**220.2**	**221.0**	**197.1**	**220.7**
Coal	12.0	9.3	6.9	6.6	5.8	4.1	3.9
Natural Gas	142.1	162.9	168.9	167.7	170.5	156.9	178.2
Fuel Oil	63.3	51.3	47.7	45.9	44.7	36.1	38.6
Residential	**338.3**	**357.8**	**336.4**	**334.7**	**327.2**	**283.1**	**329.6**
Coal	3.0	0.8	+	+	+	+	+
Natural Gas	238.0	262.2	258.8	258.6	254.7	224.8	267.1
Fuel Oil	97.4	94.9	77.6	76.2	72.6	58.3	62.5
U.S. Territories	**27.9**	**49.9**	**43.5**	**46.2**	**39.8**	**38.6**	**32.0**
Coal	0.6	3.0	3.4	3.4	3.4	3.4	3.4

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

Natural Gas	NO	1.3	1.5	1.5	1.4	2.6	2.6
Fuel Oil	27.2	45.6	38.6	41.3	34.9	32.6	26.0
Total	**3,246.9**	**3,859.9**	**3,476.7**	**3,635.2**	**3,519.8**	**3,325.2**	**3,439.3**

+ Does not exceed 0.05 MMT CO_2 Eq.
NO: Not occurring

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

Sector/Fuel Type	1990	2005	2009	2010	2011	2012	2013
Electric Power	**0.3**	**0.5**	**0.4**	**0.5**	**0.4**	**0.4**	**0.4**
Coal	0.3	0.3	0.3	0.3	0.3	0.2	0.2
Fuel Oil	+	+	+	+	+	+	+
Natural gas	0.1	0.1	0.1	0.2	0.2	0.2	0.2
Wood	+	+	+	+	+	+	+
Industrial	**1.8**	**1.7**	**1.4**	**1.5**	**1.5**	**1.5**	**1.5**
Coal	0.4	0.3	0.2	0.2	0.2	0.2	0.2
Fuel Oil	0.2	0.2	0.1	0.2	0.1	0.1	0.2
Natural gas	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Wood	1.0	1.0	0.8	0.9	0.9	1.0	0.9
Commercial/Institutional	**1.0**	**1.1**	**1.1**	**1.1**	**1.0**	**0.9**	**1.0**
Coal	+	+	+	+	+	+	+
Fuel Oil	0.2	0.2	0.2	0.2	0.2	0.1	0.1
Natural gas	0.3	0.4	0.4	0.4	0.4	0.4	0.4
Wood	0.5	0.5	0.5	0.5	0.5	0.4	0.5
Residential	**5.2**	**4.1**	**4.4**	**4.0**	**4.0**	**3.7**	**5.0**
Coal	0.2	0.1	+	+	+	+	+
Fuel Oil	0.3	0.3	0.3	0.3	0.3	0.2	0.2
Natural Gas	0.5	0.6	0.6	0.6	0.6	0.5	0.6
Wood	4.1	3.1	3.6	3.1	3.2	3.0	4.1
U.S. Territories	**+**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**+**
Coal	+	+	+	+	+	+	+
Fuel Oil	+	0.1	0.1	0.1	0.1	0.1	+
Natural Gas	+	+	+	+	+	+	+
Wood	+	+	+	+	+	+	+
Total	**8.5**	**7.4**	**7.4**	**7.1**	**7.1**	**6.6**	**8.0**

Note: Emissions values are presented in CO_2 equivalent mass units using IPCC AR4 GWP values.
+ Does not exceed 0.05 MMT CO_2 Eq.
Note: Totals may not sum due to independent rounding.

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

Sector/Fuel Type	1990	2005	2009	2010	2011	2012	2013
Electricity Generation	**7.4**	**16.0**	**16.8**	**18.5**	**17.6**	**17.8**	**19.1**
Coal	6.3	11.6	11.2	12.5	11.5	10.2	12.1
Fuel Oil	0.1	0.1	+	+	+	+	+
Natural Gas	1.0	4.3	5.6	5.9	6.1	7.5	7.0
Wood	+	+	+	+	+	+	+
Industrial	**3.1**	**2.9**	**2.3**	**2.5**	**2.4**	**2.4**	**2.4**
Coal	0.7	0.5	0.4	0.4	0.4	0.4	0.4
Fuel Oil	0.5	0.5	0.4	0.4	0.4	0.3	0.4
Natural Gas	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Wood	1.6	1.6	1.3	1.4	1.5	1.5	1.4
Commercial/Institutional	**0.4**	**0.3**	**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

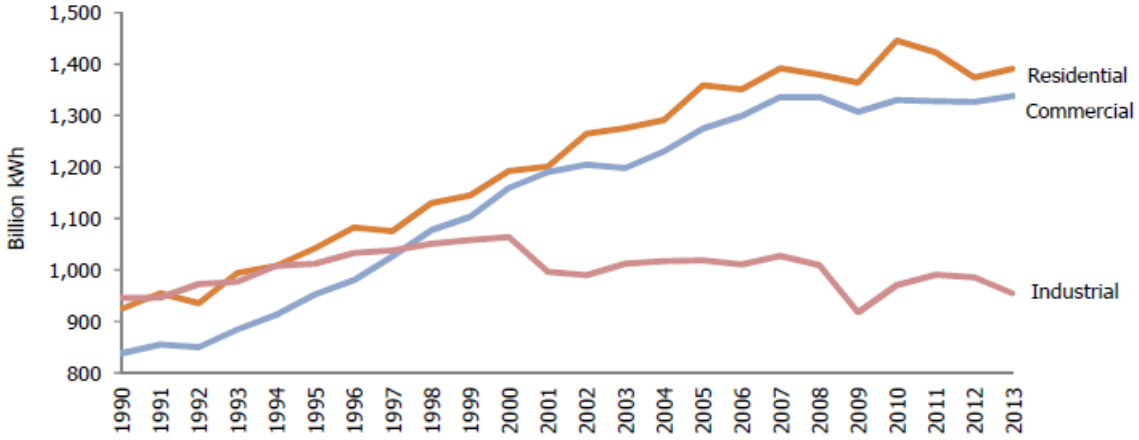
Wood	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Residential	**1.0**	**0.9**	**0.9**	**0.8**	**0.8**	**0.7**	**1.0**
Coal	+	+	+	+	+	+	+
Fuel Oil	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Natural Gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wood	0.7	0.5	0.6	0.5	0.5	0.5	0.7
U.S. Territories	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Coal	+	+	+	+	+	+	+
Fuel Oil	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Natural Gas	+	+	+	+	+	+	+
Wood	+	+	+	+	+	+	+
Total	**11.9**	**20.2**	**20.4**	**22.2**	**21.3**	**21.4**	**22.9**

Note: Emissions values are presented in CO_2 equivalent mass units using IPCC AR4 GWP values.
+ Does not exceed 0.05 MMT 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 37 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 0.9 percent, respectively. Electricity generation also accounted for the largest share of CO_2 emissions from fossil fuel combustion, approximately 39.5 percent in 2013. Methane and N_2O from electricity generation represented 4.2 and 46.3 percent of total methane and N_2O emissions from fossil fuel combustion in 2013, 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). Electricity generators, including those using low-CO_2 emitting technologies, relied on coal for approximately 39 percent of their total energy requirements in 2013. Recently an increase in the carbon intensity of fuels consumed to generate electricity has occurred due to an increase in coal consumption, and decreased natural gas consumption and other generation sources. Total U.S. electricity generators used natural gas for approximately 27 percent of their total energy requirements in 2013 (EIA 2014a).

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, while the other sectors consist of those producers that indicate their primary business is something other than the production of electricity.[14]

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 2013 increased approximately 1.2 percent and 0.9 percent, respectively. The trend in the residential and commercial sectors can largely be attributed to colder, more energy-intensive winter conditions compared to 2012. Electricity sales to the industrial sector in 2013 decreased approximately 3.1 percent. Overall, in 2013, the amount of electricity generated (in kWh) decreased approximately 0.1 percent relative to the previous year, while CO_2 emissions from the electric power sector increased by 0.9 percent. The increase in CO_2 emissions, despite the decrease in sales and electricity generation was a result of an increase in the consumption of coal and petroleum for electricity generation by 4.2 percent and 18.8 percent, respectively, in 2013, and a decrease in the consumption of natural gas for electricity generation by 10.2 percent.

Industrial Sector

Industrial sector CO_2, CH_4, and N_2O, emissions accounted for 16, 15, and 6 percent of CO_2, CH_4, and N_2O, emissions from fossil fuel combustion, respectively. 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 2015 and EIA 2009b).

In theory, emissions from the industrial sector should be highly correlated with economic growth and industrial output, but heating of industrial buildings and agricultural energy consumption are also affected by weather conditions.[15] 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.

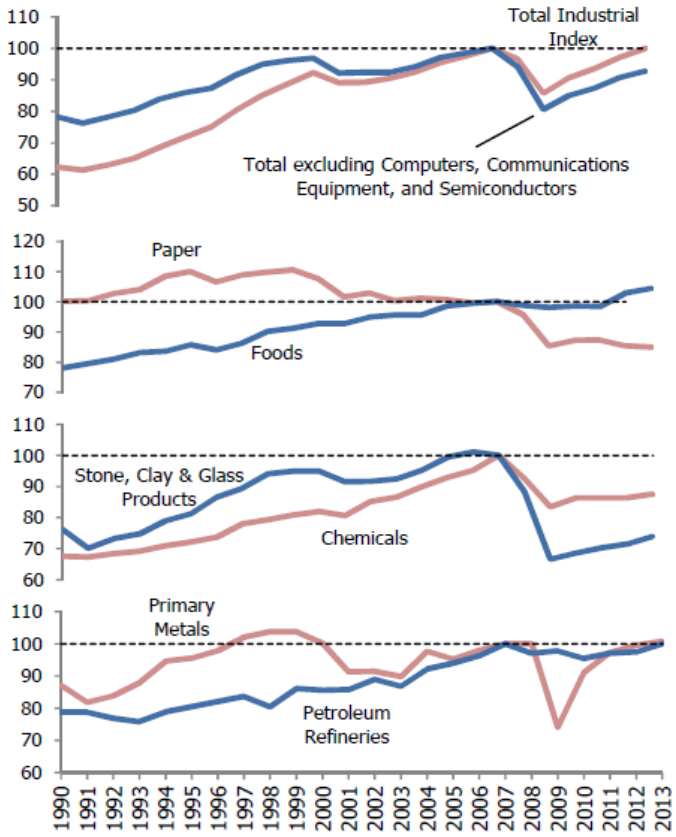
From 2012 to 2013, total industrial production and manufacturing output increased by 2.9 percent (FRB 2014). Over this period, output increased across production indices for Food, Petroleum Refineries, Chemicals, Primary Metals, and Nonmetallic Mineral Products, and decreased slightly for Paper (see Figure 3-10). Through EPA's Greenhouse Gas Reporting Program (GHGRP), industrial trends can be discerned from the overall EIA industrial fuel consumption data used for these calculations. For example, from 2012 to 2013 the underlying EIA data showed increased consumption of natural gas and petroleum fuels in the industrial sector. EPA's GHGRP data highlights that petroleum refineries, chemical manufacturing, and non-metallic mineral products were contributors to these trends.[16]

[14] 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).

[15] 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.

[16] Further details on industrial sector combustion emissions are provided by EPA's GHGRP (<http://ghgdata.epa.gov/ghgp/main.do>).

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



Despite the growth in industrial output (61 percent) and the overall U.S. economy (75 percent) from 1990 to 2013, CO_2 emissions from fossil fuel combustion in the industrial sector decreased by 3.0 percent over the same time series. 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 2013, CO_2, CH_4, and N_2O emissions from fossil fuel combustion and electricity use within the industrial end-use sector totaled 1,409.3 MMT CO_2 Eq., or approximately 1.7 percent above 2012 emissions.

Residential and Commercial Sectors

Residential and commercial sector CO_2 emissions accounted for 6 and 4 percent of CO_2 emissions from fossil fuel combustion, CH_4 emissions accounted for 49 and 10 percent of CH_4 emissions from fossil fuel combustion, and N_2O emissions accounted for 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 2013, CO_2, CH_4, and N_2O emissions from fossil fuel combustion and electricity use within the residential and commercial end-use sectors were 1,083.3 MMT CO_2 Eq. and 941.5 MMT CO_2 Eq., respectively. Total CO_2, CH_4, and N_2O emissions from fossil fuel combustion and electricity use within the residential and commercial end-use sectors increased by 6.3 and 4.0 percent from 2012 to 2013, 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).

In 2013, combustion emissions from natural gas consumption represent 81 percent of the direct fossil fuel CO_2 emissions from both the residential and commercial sectors. Natural gas combustion CO_2 emissions from the residential and commercial sectors in 2013 increased by 18.8 percent and 13.6 percent from 2012 levels, 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.

Transportation Sector and Mobile Combustion

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 1,743.0 MMT CO_2 Eq. in 2013, which represented 33 percent of CO_2 emissions, 21 percent of CH_4 emissions, and 45 percent of N_2O emissions from fossil fuel combustion, respectively.[17] Fuel purchased in the United States for international aircraft and marine travel accounted for an additional 100.7 MMT CO_2 Eq. in 2013; these emissions are recorded as international bunkers and are not included in U.S. totals according to UNFCCC reporting protocols.

From 1990 to 2013, transportation emissions from fossil fuel combustion rose by 13 percent due, in large part, to increased demand for travel with limited gains in fuel efficiency for much of this time period. The number of vehicle miles traveled (VMT) by light-duty motor vehicles (passenger cars and light-duty trucks) increased 35 percent from 1990 to 2013, as a result of a confluence of factors including population growth, economic growth, urban sprawl, and low fuel prices during the beginning of this period.

From 2012 to 2013, CO_2 emissions from the transportation end-use sector increased by 1.0 percent.[18] The increase in emissions can largely be attributed to small increases in VMT and fuel use across on-road transportation modes, as well as increases in other non-road sectors such as pipelines. Commercial aircraft emissions increased slightly between 2012 and 2013, but have decreased 18 percent since 2007. Decreases in jet fuel emissions (excluding bunkers) since 2007 are due in part to improved operational efficiency that results in more direct flight routing, improvements in aircraft and engine technologies to reduce fuel burn and emissions, and the accelerated retirement of older, less fuel efficient aircraft.

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 15 percent from 1990 to 2013. Annex 3.2 presents the total emissions from all transportation and mobile sources, including CO_2, N_2O, CH_4, and HFCs.

[17] Note that these totals include CH_4 and N_2O emissions from some sources in the U.S. Territories (ships and boats, recreational boats, non-transportation mobile sources) and CH_4 and N_2O emissions from transportation rail electricity.

[18] Note that this value does not include lubricants.

Transportation Fossil Fuel Combustion CO_2 Emissions

Domestic transportation CO_2 emissions increased by 15 percent (225.6 MMT CO_2) between 1990 and 2013, an annualized increase of 0.6 percent. Among domestic transportation sources, light duty vehicles (including passenger cars and light-duty trucks) represented 60 percent of CO_2 emissions from fossil fuel combustion, medium- and heavy-duty trucks 23 percent, commercial aircraft 7 percent, and other sources 11 percent. See Table 3-12 for a detailed breakdown of transportation CO_2 emissions by mode and fuel type.

Almost all of the energy consumed by the transportation sector is petroleum-based, including motor gasoline, diesel fuel, jet fuel, and residual oil. CO_2 emissions from the combustion of ethanol and biodiesel for transportation purposes, along with the emissions associated with the agricultural and industrial processes involved in the production of biofuel, are captured in other Inventory sectors.[19] Ethanol consumption from the transportation sector has increased from 0.7 billion gallons in 1990 to 12.6 billion gallons in 2013, while biodiesel consumption has increased from 0.01 billion gallons in 2001 to 1.4 billion gallons in 2013. For further information, see the section on biofuel consumption at the end of this chapter and Table A-93 in Annex 3.2.

CO_2 emissions from passenger cars and light-duty trucks totaled 1,028.0 MMT CO_2 in 2013, an increase of 8 percent (77.6 MMT CO_2) from 1990 due, in large part, to increased demand for travel as fleetwide light-duty vehicle fuel economy was relatively stable (average new vehicle fuel economy declined slowly from 1990 through 2004 and then increased more rapidly from 2005 through 2013). CO_2 emissions from passenger cars and light-duty trucks peaked at 1,181.2 MMT CO_2 in 2004, and since then have declined about 13 percent. The decline in new light-duty vehicle fuel economy between 1990 and 2004 (Figure 3-11) reflected the increasing market share of light-duty trucks, which grew from about 30 percent of new vehicle sales in 1990 to 48 percent in 2004 (Figure 3-12). Starting in 2005, the rate of VMT growth slowed considerably (and declined rapidly in 2008) while average new vehicle fuel economy began to increase. Average new vehicle fuel economy has improved almost every year since 2005, and the truck share has decreased to about 37 percent of new vehicles in model year 2013 (EPA 2014d).

Medium- and heavy-duty truck CO_2 emissions increased by 71 percent from 1990 to 2013. This increase was largely due to a substantial growth in medium- and heavy-duty truck VMT, which increased by 92 percent between 1990 and 2013.[20] Carbon dioxide from the domestic operation of commercial aircraft increased by 4 percent (4.4 MMT CO_2) from 1990 to 2013. Across all categories of aviation, excluding international bunkers, CO_2 emissions decreased by 21 percent (38.7 MMT CO_2) between 1990 and 2013.[21] This includes a 69 percent (24.0 MMT CO_2) decrease in CO_2 emissions from domestic military operations.

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, CH_4, N_2O, and HFCs.

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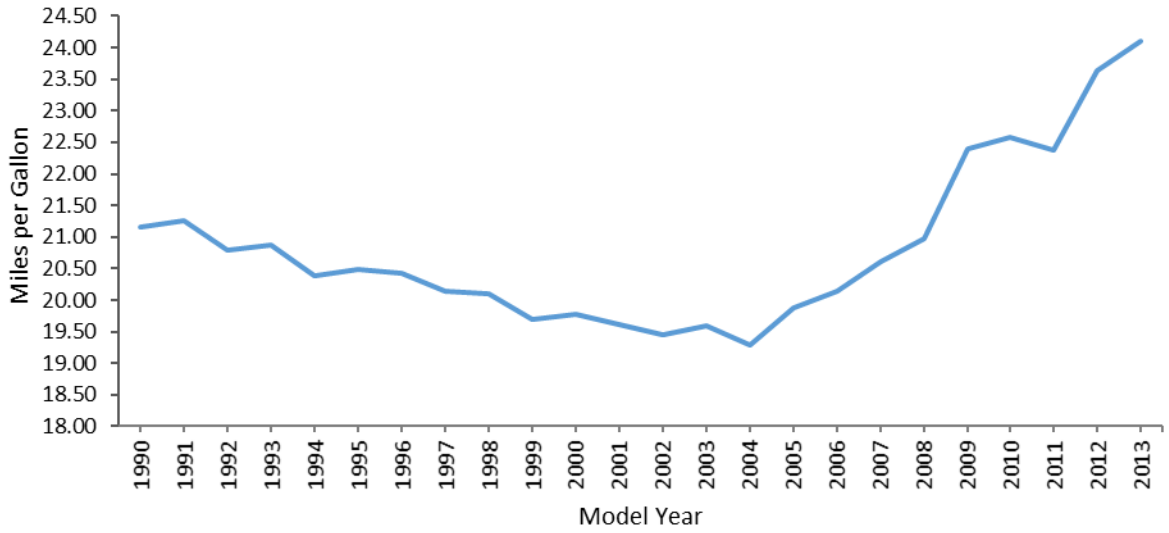
[19] Biofuel estimates are presented in the Energy chapter for informational purposes only, in line with IPCC methodological guidance and UNFCCC reporting obligations. Net carbon fluxes from changes in biogenic carbon reservoirs in croplands are accounted for in the estimates for Land Use, Land-Use Change, and Forestry (see Chapter 6). More information and additional analyses on biofuels are available at EPA's "Renewable Fuels: Regulations & Standards;" See <http://www.epa.gov/otaq/fuels/renewablefuels/regulations.htm>.

[20] While FHWA data shows consistent growth in medium- and heavy-duty truck VMT over the 1990 to 2013 time period, part of the growth reflects a method change for estimating VMT starting in 2007. 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 VMT and emissions among on-road vehicle classes in the 2007 to 2013 time period. During the time period prior to the method change (1990-2006), VMT for medium- and heavy-duty trucks increased by 51 percent.

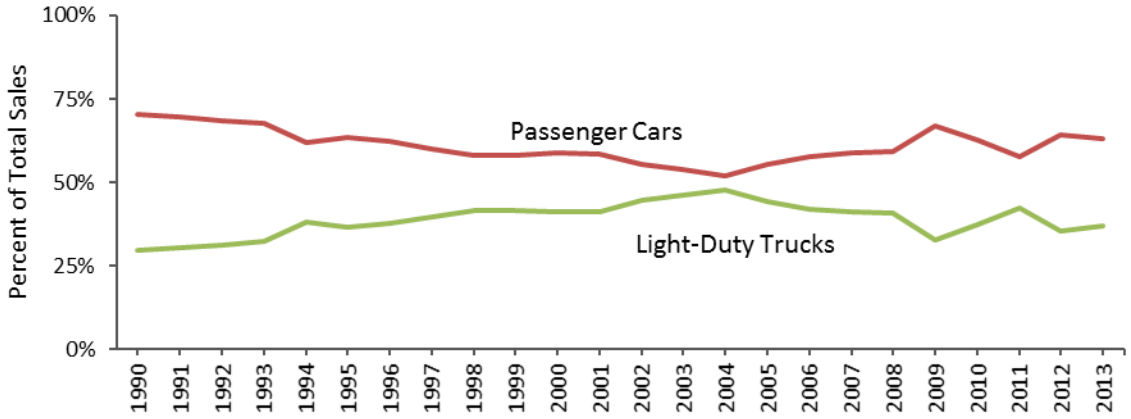
[21] Includes consumption of jet fuel and aviation gasoline. Does not include aircraft bunkers, which are not included in national emission totals, in line with IPCC methodological guidance and UNFCCC reporting obligations.

Figure 3-11: Sales-Weighted Fuel Economy of New Passenger Cars and Light-Duty Trucks, 1990–2013 (miles/gallon)



Source: EPA (2014)

Figure 3-12: Sales of New Passenger Cars and Light-Duty Trucks, 1990–2013 (percent)



Source: EPA (2014)

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

Fuel/Vehicle Type	1990	2005	2009[a]	2010	2011	2012	2013
Gasoline[c]	**983.5**	**1,183.9**	**1,101.7**	**1,092.7**	**1,069.0**	**1,064.9**	**1,065.8**
Passenger Cars	621.4	655.9	744.3	738.2	732.8	731.5	731.5
Light-Duty Trucks	309.1	477.2	296.9	295.0	280.4	277.4	277.7
Medium- and Heavy-Duty Trucks[b]	38.7	34.8	42.6	42.3	38.9	38.7	39.5
Buses	0.3	0.4	0.7	0.7	0.7	0.8	0.8
Motorcycles	1.7	1.6	4.1	3.6	3.6	4.1	3.9
Recreational Boats	12.2	14.1	13.0	12.7	12.6	12.5	12.4
Distillate Fuel Oil (Diesel)[c]	**262.9**	**458.1**	**409.0**	**425.5**	**433.7**	**431.3**	**437.6**
Passenger Cars	7.9	4.2	3.6	3.8	4.1	4.1	4.1
Light-Duty Trucks	11.5	25.8	12.1	12.6	13.1	13.0	13.0

Medium- and Heavy-Duty Trucks[b]	190.5	360.6	332.0	345.6	347.3	347.5	353.0
Buses	8.0	10.6	13.7	13.6	14.6	15.5	15.8
Rail	35.5	45.6	36.2	39.0	40.8	39.8	40.4
Recreational Boats	2.0	3.1	3.5	3.5	3.6	3.7	3.7
Ships and Other Boats	7.5	8.1	7.9	7.5	10.3	7.6	7.7
International Bunker Fuels[d]	*11.7*	*9.4*	*8.2*	*9.5*	*7.9*	*6.8*	*5.6*
Jet Fuel	**184.2**	**189.3**	**154.1**	**151.5**	**146.6**	**143.4**	**147.1**
Commercial Aircraft[e]	109.9	132.7	119.5	113.3	114.6	113.3	114.3
Military Aircraft	35.0	19.4	15.4	13.6	11.6	12.1	11.0
General Aviation Aircraft	39.4	37.3	19.2	24.6	20.4	18.0	21.8
International Bunker Fuels[d]	*38.0*	*60.1*	*52.8*	*61.0*	*64.8*	*64.5*	*65.7*
International Bunker Fuels from Commercial Aviation	*30.0*	*55.6*	*49.2*	*57.4*	*61.7*	*61.4*	*62.8*
Aviation Gasoline	**3.1**	**2.4**	**1.8**	**1.9**	**1.9**	**1.7**	**1.5**
General Aviation Aircraft	3.1	2.4	1.8	1.9	1.9	1.7	1.5
Residual Fuel Oil	**22.6**	**19.3**	**13.9**	**20.4**	**19.4**	**15.8**	**15.0**
Ships and Other Boats	22.6	19.3	13.9	20.4	19.4	15.8	15.0
International Bunker Fuels[d]	*53.7*	*43.6*	*45.4*	*46.5*	*38.9*	*34.5*	*28.5*
Natural Gas	**36.0**	**33.1**	**37.9**	**38.1**	**38.9**	**41.3**	**48.8**
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+
Buses	+	0.8	1.2	1.1	1.1	1.0	1.0
Pipeline[f]	36.0	32.2	36.7	37.1	37.8	40.3	47.7
LPG	**1.4**	**1.7**	**1.7**	**1.8**	**2.1**	**2.3**	**2.5**
Light-Duty Trucks	0.6	1.3	1.2	1.3	1.5	1.6	1.8
Medium- and Heavy-Duty Trucks[b]	0.8	0.4	0.5	0.6	0.6	0.7	0.7
Buses	+	+	+	+	+	+	+
Electricity	**3.0**	**4.7**	**4.5**	**4.5**	**4.3**	**3.9**	**4.0**
Rail	3.0	4.7	4.5	4.5	4.3	3.9	4.0
Ethanol[g]	***4.1***	***22.4***	***61.2***	***71.3***	***71.5***	***71.5***	***73.4***
Total	**1,496.8**	**1,892.5**	**1,724.8**	**1,736.5**	**1,715.8**	**1,704.6**	**1,722.4**
Total (Including Bunkers)[d]	**1,600.3**	**2,005.7**	**1,831.2**	**1,853.4**	**1,827.5**	**1,810.4**	**1,822.2**

Note: 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. In addition, this table does not include CO_2 emissions from U.S. Territories, since these are covered in a separate chapter of the Inventory.

[a] In 2011 FHWA changed its methods for estimating vehicle miles traveled (VMT) and related data. These methodological changes included how vehicles are classified, moving from a system based on body-type to one that is based on wheelbase. These changes were first incorporated for the 2010 Inventory and apply to the 2007-13 time period. This resulted in large changes in VMT and fuel consumption data by vehicle class, thus leading to a shift in emissions among on-road vehicle classes.

[b] Includes medium- and heavy-duty trucks over 8,500 lbs.

[c] Gasoline and diesel highway vehicle fuel consumption estimates are based on data from FHWA Highway Statistics Table VM-1 and MF-27.

[d] Official estimates exclude emissions from the combustion of both aviation and marine international bunker fuels; however, estimates including international bunker fuel-related emissions are presented for informational purposes.

[e] Commercial aircraft, as modeled in FAA's AEDT, consists of passenger aircraft, cargo, and other chartered flights.

[f] Pipelines reflect CO_2 emissions from natural gas powered pipelines transporting natural gas.

[g] Ethanol estimates are presented for informational purposes only. See Section 3.10 of this chapter and the estimates in Land Use, Land-Use Change, and Forestry (see Chapter 6), in line with IPCC methodological guidance and UNFCCC reporting obligations, for more information on ethanol.

Note: Totals may not sum due to independent rounding.

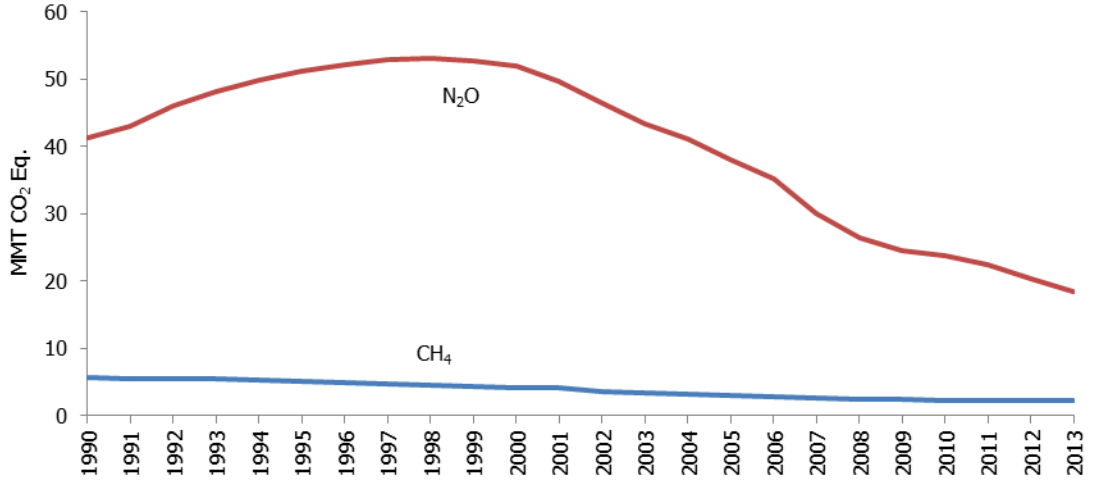
+ Less than 0.05 MMT CO_2 Eq.

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;[22] 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.).[23] Annex 3.2 includes a summary of all emissions from both transportation and mobile sources. Table 3-13 and Table 3-14 provide mobile fossil fuel CH_4 and N_2O emission estimates in MMT CO_2 Eq.[24]

Mobile combustion was responsible for a small portion of national CH_4 emissions (0.3 percent) but was the third largest source of U.S. N_2O emissions (5.2 percent). From 1990 to 2013, mobile source CH_4 emissions declined by 62 percent, to 2.1 MMT CO_2 Eq. (86 kt CH_4), 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 55 percent, to 18.4 MMT CO_2 Eq. (62 kt N_2O). Earlier generation control technologies initially resulted in higher N_2O emissions, causing a 28 percent increase in N_2O emissions from mobile sources between 1990 and 1997. Improvements in later-generation emission control technologies have reduced N_2O output, resulting in a 65 percent decrease in mobile source N_2O emissions from 1997 to 2013 (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 (MMT CO_2 Eq.)



Note: Emissions values are presented in CO_2 equivalent mass units using IPCC AR4 GWP values.

[22] Emissions of CH_4 from natural gas systems are reported separately. More information on the methodology used to calculate these emissions are included in this chapter and Annex 3.4.

[23] See the methodology sub-sections of the CO_2 from Fossil Fuel Combustion and CH_4 and N_2O from Mobile Combustion sections of this chapter. Note that N_2O and CH_4 emissions are reported using different categories than CO_2. CO_2 emissions are reported by end-use sector (Transportation, Industrial, Commercial, Residential, U.S Territories), and generally adhere to a top-down approach to estimating emissions. CO_2 emissions from non-transportation sources (e.g., lawn and garden equipment, farm equipment, construction equipment) are allocated to their respective end-use sector (i.e., construction equipment CO_2 emissions are included in the Commercial end-use sector instead of the Transportation end-use sector). CH_4 and N_2O emissions are reported using the "Mobile Combustion" category, which includes non-transportation mobile sources. CH_4 and N_2O emissions estimates are bottom-up estimates, based on total activity (fuel use, VMT) and emissions factors by source and technology type. These reporting schemes are in accordance with IPCC guidance. For informational purposes only, CO_2 emissions from non-transportation mobile sources are presented separately from their overall end-use sector in Annex 3.2.

[24] See Annex 3.2 for a complete time series of emission estimates for 1990 through 2013.

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

Fuel Type/Vehicle Type[a]	1990	2005	2009	2010	2011	2012	2013
Gasoline On-Road[b]	**5.2**	**2.4**	**1.7**	**1.7**	**1.6**	**1.5**	**1.5**
Passenger Cars	3.2	1.4	1.2	1.2	1.2	1.1	1.0
Light-Duty Trucks	1.7	0.9	0.4	0.4	0.4	0.3	0.3
Medium- and Heavy-Duty Trucks and Buses	0.3	0.1	0.1	0.1	0.1	0.1	0.1
Motorcycles	+	+	+	+	+	+	+
Diesel On-Road[b]	**+**	**+**	**+**	**+**	**+**	**+**	**+**
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**
Non-Road	**0.4**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.6**
Ships and Boats	+	+	+	+	+	+	+
Rail[f]	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Aircraft	0.1	0.1	+	+	+	+	+
Agricultural Equipment[c]	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Construction/Mining Equipment[d]	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Other[e]	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**5.6**	**3.0**	**2.3**	**2.3**	**2.3**	**2.2**	**2.1**

Note: Emissions values are presented in CO_2 equivalent mass units using IPCC AR4 GWP values. Totals may not sum due to independent rounding.

Note: In 2011, FHWA changed its methods for estimating vehicle miles traveled (VMT) and related data. These methodological changes included how vehicles are classified, moving from a system based on body-type to one that is based on wheelbase. These changes were first incorporated for the 1990-2010 Inventory and apply to the 2007 through 2013 time period. This resulted in large changes in VMT and fuel consumption data by vehicle class, thus leading to a shift in emissions among on-road vehicle classes.

[a] See Annex 3.2 for definitions of on-road vehicle types.

[b] Gasoline and diesel highway vehicle mileage are based on data from FHWA Highway Statistics Table VM-1.

[c] Includes equipment, such as tractors and combines, as well as fuel consumption from trucks that are used off-road in agriculture.

[d] Includes equipment, such as cranes, dumpers, and excavators, as well as fuel consumption from trucks that are used off-road in construction.

[e] "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.

[f] Rail emissions do not include emissions from electric powered locomotives.

+ Less than 0.05 MMT CO_2 Eq.

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

Fuel Type/Vehicle Type[a]	1990	2005	2009	2010	2011	2012	2013
Gasoline On-Road[b]	**37.4**	**33.6**	**20.4**	**19.2**	**18.0**	**15.8**	**13.9**
Passenger Cars	24.1	18.0	13.8	12.9	12.3	10.7	9.3
Light-Duty Trucks	12.7	14.8	5.7	5.5	5.0	4.4	3.9
Medium- and Heavy-Duty Trucks and Buses	0.5	0.8	0.8	0.8	0.7	0.7	0.7
Motorcycles	+	+	+	+	+	+	+
Diesel On-Road[b]	**0.2**	**0.3**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+
Medium- and Heavy-Duty Trucks and Buses	0.2	0.3	0.4	0.4	0.4	0.4	0.4

Alternative Fuel On-Road	**0.1**	**0.1**	**0.1**	**0.2**	**0.2**	**0.2**	**0.2**
Non-Road	**3.5**	**4.1**	**3.7**	**4.0**	**4.0**	**3.9**	**3.9**
Ships and Boats	0.6	0.6	0.5	0.8	0.8	0.7	0.7
Rail[f]	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Aircraft	1.7	1.8	1.4	1.4	1.4	1.3	1.4
Agricultural Equipment[c]	0.2	0.3	0.3	0.4	0.4	0.4	0.4
Construction/Mining Equipment[d]	0.3	0.5	0.5	0.5	0.6	0.6	0.6
Other[e]	0.4	0.6	0.6	0.6	0.6	0.6	0.6
Total	**41.2**	**38.1**	**24.6**	**23.7**	**22.5**	**20.2**	**18.4**

Note: Emissions values are presented in CO_2 equivalent mass units using IPCC AR4 GWP values. Totals may not sum due to independent rounding.

Note: In 2011, FHWA changed its methods for estimating vehicle miles traveled (VMT) and related data. These methodological changes included how vehicles are classified, moving from a system based on body type to one that is based on wheelbase. These changes were first incorporated for the 1990-2010 Inventory and apply to the 2007 through 2013 time period. This resulted in large changes in VMT and fuel consumption data by vehicle class, thus leading to a shift in emissions among on-road vehicle classes.

[a] See Annex 3.2 for definitions of on-road vehicle types.

[b] Gasoline and diesel highway vehicle mileage are based on data from FHWA Highway Statistics Table VM-1.

[c] Includes equipment, such as tractors and combines, as well as fuel consumption from trucks that are used off-road in agriculture.

[d] Includes equipment, such as cranes, dumpers, and excavators, as well as fuel consumption from trucks that are used off-road in construction.

[e] "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.

[f] Rail emissions do not include emissions from electric powered locomotives.

+ Less than 0.05 MMT 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).[25] The use of the most recently published calculation methodologies by the IPCC, as contained in the *2006 IPCC Guidelines*, is considered to improve the rigor and accuracy of this inventory and is fully in line with IPCC Good Practice Guidance. 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 EIA of the U.S. Department of Energy (DOE), primarily from the Monthly Energy Review and published supplemental tables on petroleum product detail (EIA 2015). The EIA does not include territories in its national energy statistics, so fuel consumption data for territories were collected separately from EIA's International Energy Statistics (EIA 2013) and Jacobs (2010).[26]

   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

[25] The IPCC Tier 3B methodology is used for estimating emissions from commercial aircraft.

[26] 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 32.1 MMT CO_2 Eq. in 2013.

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 periodic basis (every four years). These consumption data sets help inform the annual surveys to arrive at the national total and sectoral breakdowns for that total.[27]

Also, 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).[28]

2. *Subtract uses accounted for in the Industrial Processes and Product Use 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 and Product Use chapter, as they were consumed during non-energy related industrial activity. To make these adjustments, additional data were collected from AISI (2004 through 2013), Coffeyville (2014), U.S. Census Bureau (2011), EIA (2014c), USGS (1991 through 2011), USGS (1994 through 2011), USGS (1995, 1998, 2000 through 2002), USGS (2007), USGS (2009), USGS (2010), USGS (2011), USGS (1991 through 2010a), USGS (1991 through 2010b), USGS (2012a) and USGS (2012b).[29]

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.[30] 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.[31] 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 (2015), data for synthetic natural gas were collected from EIA (2014), and data for CO_2 exports were collected from the Eastman Gasification Services Company (2011), Dakota Gasification Company (2006), Fitzpatrick (2002), Erickson (2003), EIA (2008) 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 data from the Federal Highway Administration 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 to match the value obtained from the bottom-up analysis. As the total distillate and motor gasoline consumption estimate from EIA are considered to be accurate at the national level, the distillate and motor gasoline consumption totals for the residential, commercial, and industrial sectors were adjusted proportionately. The data sources used in the bottom-up analysis of transportation fuel consumption include AAR (2008 through 2013), Benson

[27] 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.

[28] 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.

[29] 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 and Product Use chapter.

[30] Energy statistics from EIA (2015) are already adjusted downward to account for ethanol added to motor gasoline, and biogas in natural gas.

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

(2002 through 2004), DOE (1993 through 2014), EIA (2007), EIA (1991 through 2014), EPA (2013b), and FHWA (1996 through 2014).[32]

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 (2015).

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).[33] The Office of the Under Secretary of Defense (Installations and Environment) and the Defense Logistics Agency Energy (DLA Energy) of the U.S. Department of Defense (DoD) (DLA Energy 2014) supplied data on military jet fuel and marine fuel use. Commercial jet fuel use was obtained from FAA (2015); residual and distillate fuel use for civilian marine bunkers was obtained from DOC (1991 through 2013) for 1990 through 2001 and 2007 through 2013, 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 GHGRP (EPA 2010). 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

[32] The source of highway vehicle VMT and fuel consumption is FHWA's VM-1 table. In 2011, FHWA changed its methods for estimating data in the VM-1 table. These methodological changes included how vehicles are classified, moving from a system based on body type to one that is based on wheelbase. These changes were first incorporated for the 1990-2010 Inventory and apply to the 2007 to 2013 time period. This resulted in large changes in VMT and fuel consumption data by vehicle class, thus leading to a shift in emissions among on-road vehicle classes. For example, the category "Passenger Cars" has been replaced by "Light-duty Vehicles-Short Wheelbase" and "Other 2 axle-4 Tire Vehicles" has been replaced by "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.

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

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. Heat contents and densities were obtained from EIA (2015) and USAF (1998).[34]

- For on-road vehicles, annual estimates of combined motor gasoline and diesel fuel consumption by vehicle category were obtained from FHWA (1996 through 2014); for each vehicle category, the percent gasoline, diesel, and other (e.g., CNG, LPG) fuel consumption are estimated using data from DOE (1993 through 2013).
- For non-road vehicles, activity data were obtained from AAR (2008 through 2013), APTA (2007 through 2013), APTA (2006), BEA (1991 through 2013), Benson (2002 through 2004), DOE (1993 through 2014), DLA Energy (2014), DOC (1991 through 2013), DOT (1991 through 2013), EIA (2009a), EIA (2015), EIA (2002), EIA (1991 through 2014), EPA (2014c), and Gaffney (2007).
- For jet fuel used by aircraft, CO_2 emissions from commercial aircraft were developed by the U.S. Federal Aviation Administration (FAA) using a Tier 3B methodology, consistent with the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (see Annex 3.3). CO_2 emissions from other aircraft were calculated directly based on reported consumption of fuel as reported by EIA. Allocation to domestic military uses was made using DoD data (see Annex 3.8). General aviation jet fuel consumption is calculated as the remainder of total jet fuel use (as determined by EIA) nets all other jet fuel use as determined by FAA and DoD. For more information, see Annex 3.2.

Box 3-4: Uses of Greenhouse Gas Reporting Program Data and Improvements in Reporting Emissions from Industrial Sector Fossil Fuel Combustion

As described in the calculation methodology, total fossil fuel consumption for each year is based on aggregated end-use sector consumption published by the EIA. The availability of facility-level combustion emissions through EPA's Greenhouse Gas Reporting Program (GHGRP) has provided an opportunity to better characterize the industrial sector's energy consumption and emissions in the United States, through a disaggregation of EIA's industrial sector fuel consumption data from select industries.

For EPA's GHGRP 2010, 2011, 2012, and 2013 reporting years, facility-level fossil fuel combustion emissions reported through the GHGRP were categorized and distributed to specific industry types by utilizing facility-reported NAICS codes (as published by the U.S. Census Bureau), and associated data available from EIA's 2010 Manufacturing Energy Consumption Survey (MECS). As noted previously in this report, the definitions and provisions for reporting fuel types in EPA's GHGRP include some differences from the inventory's use of EIA national fuel statistics to meet the UNFCCC reporting guidelines. The IPCC has provided guidance on aligning facility-level reported fuels and fuel types published in national energy statistics, which guided this exercise.[35]

This year's effort represents an attempt to align, reconcile, and coordinate the facility-level reporting of fossil fuel combustion emissions under EPA's GHGRP with the national-level approach presented in this report. Consistent with recommendations for reporting the inventory to the UNFCCC, progress was made on certain fuel types for specific industries and has been included in the Common Reporting Format (CRF) tables that are submitted to the UNFCCC along with this report.[36] However, a full mapping was not completed this year due to fuel category differences between national statistics published by EIA and facility-level reported GHGRP data. Furthermore, given that calendar year 2010 was the first year in which emissions data were reported to EPA's GHGRP, the current inventory's examination only focused on 2010, 2011, 2012 and 2013. For the current exercise, the efforts in reconciling fuels focused on standard, common fuel types (e.g., natural gas, distillate fuel oil, etc.) where the fuels in EIA's national statistics aligned well with facility-level GHGRP data. For these reasons, the current information

[34] 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 3.8.
[35] See Section 4 "Use of Facility-Level Data in Good Practice National Greenhouse Gas Inventories" of the IPCC meeting report, and specifically the section on using facility-level data in conjunction with energy data, at <http://www.ipcc-nggip.iges.or.jp/meeting/pdfiles/1008_Model_and_Facility_Level_Data_Report.pdf>.
[36] See < http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html>.

presented in the CRF tables should be viewed as an initial attempt at this exercise. Additional efforts will be made for future inventory reports to improve the mapping of fuel types, and examine ways to reconcile and coordinate any differences between facility-level data and national statistics. Additionally, in order to expand this effort through the full time series presented in this report, further analyses will be conducted linking GHGRP facility-level reporting with the information published by EIA in its MECS data, other available MECS survey years , and any further informative sources of data. It is believed that the current analysis has led to improvements in the presentation of data in the Inventory, but further work will be conducted, and future improvements will be realized in subsequent Inventory reports.

Additionally, to assist in the disaggregation of industrial fuel consumption, EIA will now synthesize energy consumption data using the same procedure as is used for the last historical (benchmark) year of the Annual Energy Outlook (AEO). This procedure reorganizes the most recent data from the Manufacturing Energy Consumption Survey (MECS) (conducted every four years) into the nominal data submission year using the same energy-economy integrated model used to produce the AEO projections, the National Energy Modeling System (NEMS). EIA believes this "nowcasting" technique provides an appropriate estimate of energy consumption for the CRF.

To address gaps in the time series, EIA performs a NEMS model projection, using the MECS baseline sub-sector energy consumption. The NEMS model accounts for changes in factors that influence industrial sector energy consumption, and has access to data which may be more recent than MECS, such as industrial sub-sector macro industrial output (i.e., shipments) and fuel prices. By evaluating the impact of these factors on industrial subsector energy consumption, NEMS can anticipate changes to the energy shares occurring post-MECS and can provide a way to appropriately disaggregate the energy-related emissions data into the CRF.

While the fuel consumption values for the various manufacturing sub-sectors are not directly surveyed for all years, they represent EIA's best estimate of historical consumption values for non-MECS years. Moreover, as an integral part of each AEO publication, this synthetic data series is likely to be maintained consistent with all available EIA and non-EIA data sources even as the underlying data sources evolve for both manufacturing and non-manufacturing industries alike.

Other sectors' fuel consumption (commercial, residential, transportation) will be benchmarked with the latest aggregate values from the Monthly Energy Review.[37] EIA will work with EPA to back cast these values to 1990.

Box 3-5: 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 MMT CO_2 Eq./QBtu for natural gas to upwards of 95 MMT CO_2 Eq./QBtu for coal and petroleum coke.[38] 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

[37] See <http://www.eia.gov/totalenergy/data/monthly/>.

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

sector was closely related to the C content of petroleum products (e.g., motor gasoline and jet fuel, both around 70 MMT 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.

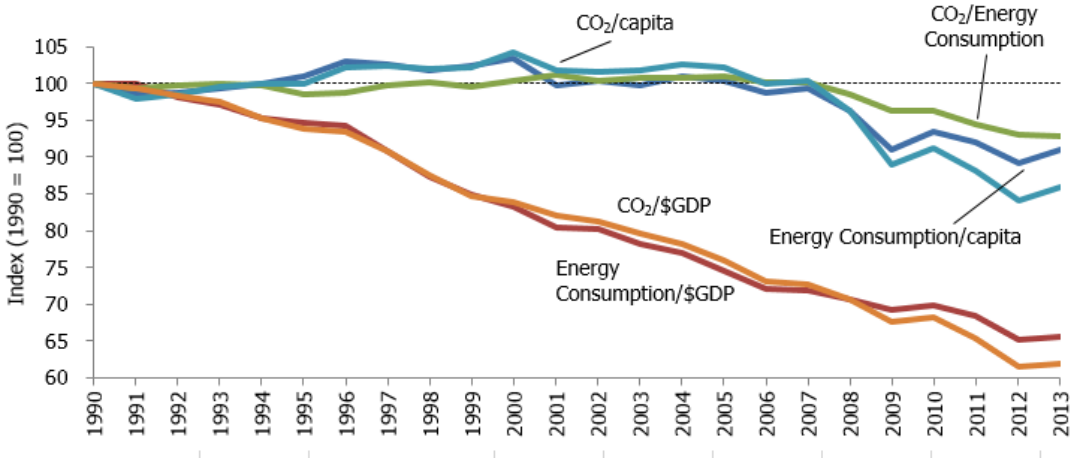
Table 3-15: Carbon Intensity from Direct Fossil Fuel Combustion by Sector (MMT CO_2 Eq./QBtu)

Sector	1990	2005	2009	2010	2011	2012	2013
Residential[a]	57.4	56.6	55.9	55.8	55.8	55.6	55.3
Commercial[a]	59.1	57.5	56.9	56.8	56.6	56.1	55.9
Industrial[a]	64.3	64.3	63.0	62.9	62.4	62.0	61.8
Transportation[a]	71.1	71.4	71.5	71.5	71.5	71.5	71.4
Electricity Generation[b]	87.3	85.8	83.7	83.6	82.9	79.9	81.3
U.S. Territories[c]	73.0	73.4	73.1	73.0	73.1	72.3	72.2
All Sectors[c]	**73.0**	**73.5**	**72.4**	**72.4**	**72.0**	**70.9**	**70.9**

[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-four-year period of 1990 through 2013, 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 2013 was approximately 9.0 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 2014).

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 (2015), EPA (2010a), and fossil fuel consumption data as discussed above and presented in Annex 2.1.

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. 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 Approach 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.[39] 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.[40]

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[39] 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.

[40] 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.

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).[41] For purposes of this uncertainty analysis, each input variable was simulated 10,000 times through Monte Carlo sampling.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-16. Fossil fuel combustion CO_2 emissions in 2013 were estimated to be between 5,051.0 and 5,403.7 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 2 percent below to 5 percent above the 2013 emission estimate of 5,157.7 MMT CO_2 Eq.

Table 3-16: Approach 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Energy-related Fossil Fuel Combustion by Fuel Type and Sector (MMT CO_2 Eq. and Percent)

Fuel/Sector	2013 Emission Estimate (MMT CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (MMT CO_2 Eq.)		(%)	
		Lower Bound	Upper Bound	Lower Bound	Upper Bound
Coal[b]	**1,658.1**	**1,600.7**	**1,814.7**	**-3%**	**9%**
Residential	NE	NE	NE	NE	NE
Commercial	3.9	3.7	4.5	-5%	15%
Industrial	75.8	72.2	87.7	-5%	16%
Transportation	NE	NE	NE	NE	NE
Electricity Generation	1,575.0	1,513.3	1,726.4	-4%	10%
U.S. Territories	3.4	3.0	4.1	-12%	19%
Natural Gas[b]	**1,389.5**	**1,374.4**	**1,453.5**	**-1%**	**5%**
Residential	267.2	259.6	285.9	-3%	7%
Commercial	178.2	173.2	190.8	-3%	7%
Industrial	450.8	437.3	483.2	-3%	7%
Transportation	48.8	47.4	52.2	-3%	7%
Electricity Generation	441.9	429.1	464.4	-3%	5%
U.S. Territories	2.6	2.3	3.1	-12%	17%
Petroleum[b]	**2,109.6**	**1,982.0**	**2,232.6**	**-6%**	**6%**
Residential	62.5	59.0	65.7	-6%	5%
Commercial	38.6	36.7	40.3	-5%	4%
Industrial	290.6	236.7	340.7	-19%	17%
Transportation	1,669.6	1,560.6	1,779.5	-7%	7%
Electric Utilities	22.4	21.2	24.4	-5%	9%
U.S. Territories	26.0	24.0	28.8	-8%	11%
Total (excluding Geothermal)[b]	**5,157.3**	**5,050.5**	**5,403.3**	**-2%**	**5%**
Geothermal	0.4	NE	NE	NE	NE
Total (including Geothermal)[b,c]	**5,157.7**	**5,051.0**	**5,403.7**	**-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.

[41] 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.

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990 through 2013. 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 2015) updated energy consumption statistics across the time series relative to the previous Inventory. One such revision is the historical petroleum consumption in the residential sector in 2011 and 2012. These revisions primarily impacted the previous emission estimates from 2010 to 2012; however, additional revisions to industrial and transportation petroleum consumption as well as industrial natural gas and coal consumption impacted emission estimates across the time series. In addition, EIA revised the heat contents of motor gasoline, distillate fuel, and petroleum coke.

For motor gasoline, heating values were previously based on the relative volumes of conventional and reformulated gasoline in the total motor gasoline product supplied to the United States. The revised heating values (first occurring in the January 2015 publication of the Monthly Energy Review) incorporated inputs of ethanol, methyl tert-butyl ether (MTBE) through April 2006, other oxygenates through 2006, and a single national hydrocarbon gasoline blend-stock from 1993 through 2013. Under the previous MER approach, the heating values of conventional and reformulated gasoline were not adjusted for annual variation in the volumes of oxygenates, such as ethanol and MTBE, which have lower heating values than the hydrocarbon components used to produce gasoline. The calculation from the previous EIA Monthly Energy Review publication resulted in overestimated energy values of historic gasoline consumption since 2003, when ethanol use began to grow rapidly. The heating value revision resulted in an historical motor gasoline consumption decrease of approximately 1 percent per year between 1994 through 2012.

Changes to the heat content of distillate fuel resulted in an annual average decrease of approximately 0.1 percent between 1994 through 2012. This decrease was a result of EIA's heat content revision from a constant sulfur content across the time series, to a weighted sulfur content. Additionally, in 2009, EIA began subtracting inputs of renewable diesel fuel from petroleum consumption before converting to energy units. Also, new data from Oak Ridge National Laboratory's Transportation Energy Book (Edition 33) regarding the use of biodiesel in transit buses was incorporated and impacted the distribution of fuel consumption and emissions for on-road buses for the time series starting in 2006.

Petroleum coke consumption decreased by an annual average of approximately 0.1 percent from 2004 to 2012. This decrease was a result of a similar heat content revision in which the EIA recalculated the historically constant petroleum coke heat content to include weighted petroleum coke heat contents (by the two categories of petroleum coke, catalyst and marketable) starting in 2004.

Overall, these changes resulted in an average annual decrease of 9.6 MMT CO_2 Eq. (less than 0.2 percent) in CO_2 emissions from fossil fuel combustion for the period 1990 through 2012, relative to the previous report.

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 GHGRP will continue to 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, some facility-level fuel combustion emissions reported under the GHGRP may also include industrial process emissions.[42] In line with UNFCCC reporting guidelines, fuel combustion emissions are included in this chapter, while process emissions are included in the Industrial Processes and Product Use 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. Additional, analyses will be conducted to align reported facility-level fuel types and IPCC fuel types per the national energy statistics. Additional work will commence to ensure 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 continue to be relied upon.[43]

Another planned improvement is to 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 is currently being investigated.

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 the current Inventory report, 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 Monthly Energy Review (EIA 2015). Fuel consumption data for coal, natural gas, and fuel oil for the United States were also obtained from EIA's Monthly Energy Review and unpublished supplemental tables on petroleum product detail (EIA 2015). Because the United States does not include territories in its national energy statistics, fuel consumption data for territories were provided separately by EIA's International Energy Statistics (EIA 2013) and Jacobs (2010).[44] Fuel consumption for the industrial sector was adjusted to subtract out construction and agricultural use, which is reported under mobile sources.[45] Construction and agricultural fuel use

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

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

[44] 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.

[45] 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.

was obtained from EPA (2014). 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

The electric power sector now uses a Tier 2 emission estimation methodology as fuel consumption for the electricity generation sector by control-technology type was obtained from EPA's Acid Rain Program Dataset (EPA 2014a). This combustion technology- and fuel-use data was available by facility from 1996 to 2013 The Tier 2 emission factors used were taken from the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC 2006), which in turn are based on emission factors published by EPA.

Since there was a difference between the EPA (2014a) and EIA (2015) total energy consumption estimates, the remaining energy consumption from EIA (2015) was apportioned to each combustion technology type and fuel combination using a ratio of energy consumption by technology type from 1996 to 2013.

Energy consumption estimates were not available from 1990 to 1995 in the EPA (2014a) dataset, and as a result, consumption was calculated using total electric power consumption from EIA (2015) and the ratio of combustion technology and fuel types from EPA (2015). 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 (2014a) and EIA (2015) datasets. The higher wood biomass consumption from EIA (2015) 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 (2015).

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 Approach 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.[46] For these variables, the uncertainty

[46] 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

ranges were assigned to the input variables based on the data reported in SAIC/EIA (2001).[47] However, the CH_4 emission factors differ from those used by EIA. These factors and uncertainty ranges are based on IPCC default uncertainty estimates (IPCC 2006).

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-17. Stationary combustion CH_4 emissions in 2013 (*including* biomass) were estimated to be between 4.6 and 20.4 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 42 percent below to 157 percent above the 2013 emission estimate of 8.0 MMT CO_2 Eq.[48] Stationary combustion N_2O emissions in 2013 (*including* biomass) were estimated to be between 16.8 and 32.0 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 27 percent below to 40 percent above the 2013 emissions estimate of 22.9 MMT CO_2 Eq.

Table 3-17: Approach 2 Quantitative Uncertainty Estimates for CH_4 and N_2O Emissions from Energy-Related Stationary Combustion, Including Biomass (MMT CO_2 Eq. and Percent)

Source	Gas	2013 Emission Estimate (MMT CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (MMT CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Stationary Combustion	CH_4	8.0	4.6	20.4	-42%	+157%
Stationary Combustion	N_2O	22.9	16.8	32.0	-27%	+40%

[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 2013. 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

For the current Inventory, emission estimates have been revised to reflect the GWPs provided in the *IPCC Fourth Assessment Report* (AR4) (IPCC 2007). AR4 GWP values differ slightly from those presented in the *IPCC Second Assessment Report* (SAR) (IPCC 1996) (used in the previous Inventories) which results in time-series recalculations

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.

[47] 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.

[48] 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.

for most inventory sources. Under the most recent reporting guidelines (UNFCCC 2014), countries are required to report using the AR4 GWPs, which reflect an updated understanding of the atmospheric properties of each greenhouse gas. The GWPs of CH_4 and most fluorinated greenhouse gases have increased, leading to an overall increase in emissions from CH_4, HFCs, and PFCs. The GWPs of N_2O and SF_6 have decreased, leading to a decrease in emissions. The AR4 GWPs have been applied across the entire time series for consistency. For more information please see the Recalculations and Improvements Chapter.

Methane and N_2O emissions from stationary sources (excluding CO_2) across the entire time series were revised due revised data from EIA (2015) and EPA (2014a) relative to the previous Inventory. In addition, with the adoption of new GWPs, the entire time series from 1990 through 2012 decreased. The historical data changes resulted in an average annual decrease of 0.3 MMT CO_2 Eq. (4 percent) in CH_4 emissions from stationary combustion and an average annual increase of less than 0.2 MMT CO_2 Eq. (1 percent) in N_2O emissions from stationary combustion for the period 1990 through 2012.

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.

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.[49]

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) are based on VMT and emission factors by vehicle and fuel type.[50]

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

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

[50] 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.

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.[51]

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 2013 were obtained from the Federal Highway Administration's (FHWA) Highway Performance Monitoring System database as reported in Highway Statistics (FHWA 1996 through 2014).[52] 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 2014) and information on total motor vehicle fuel consumption by fuel type from FHWA (1996 through 2014). VMT for AFVs were estimated based on Browning (2003) and Browning (2015). The age distributions of the U.S. vehicle fleet were obtained from EPA (2013c, 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 (1994a, 1994b, 1998, 1999a) and IPCC (2006).

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).[53] Activity data were obtained from AAR (2008 through 2013), APTA (2007 through 2013), APTA (2006), BEA (1991 through 2013), Benson (2002 through 2004), DHS (2008), DLA Energy (2014), DOC (1991 through 2013), DOE (1993 through 2013), DOT (1991 through 2013), EIA (2002, 2008, 2007, 2014), EIA (2007 through 2015), EIA (1991 through 2014), EPA (2014d), Esser (2003 through 2004), FAA (2015), FHWA (1996 through 2014), Gaffney (2007), and Whorton (2006 through 2013). Emission factors for non-road modes were taken from IPCC (2006) and Browning (2009).

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

[52] The source of VMT is FHWA's VM-1 table. In 2011, FHWA changed its methods for estimating data in the VM-1 table. These methodological changes included how vehicles are classified, moving from a system based on body-type to one that is based on wheelbase. These changes were first incorporated for the 2010 Inventory and apply to the 2007-12 time period. This resulted in large changes in VMT by vehicle class, thus leading to a shift in emissions among on-road vehicle classes. For example, the category "Passenger Cars" has been replaced by "Light-duty Vehicles-Short Wheelbase" and "Other 2 axle-4 Tire Vehicles" has been replaced by "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.

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

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis was conducted for the mobile source sector using the IPCC-recommended Approach 2 uncertainty estimation methodology, Monte Carlo Stochastic Simulation technique, using @RISK software. The uncertainty analysis was performed on 2013 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) 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. For more information, see Section 3.8. However, a much higher level of uncertainty is associated with CH_4 and N_2O emission factors due to limited 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 2013 were estimated to be between 1.9 and 2.6 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 13 percent below to 21 percent above the corresponding 2013 emission estimate of 2.1 MMT CO_2 Eq. Also at a 95 percent confidence level, mobile combustion N_2O emissions from mobile sources in 2013 were estimated to be between 16.6 and 22.1 MMT CO_2 Eq., indicating a range of 10 percent below to 20 percent above the corresponding 2013 emission estimate of 18.4 MMT CO_2 Eq.

Table 3-18: Approach 2 Quantitative Uncertainty Estimates for CH_4 and N_2O Emissions from Mobile Sources (MMT CO_2 Eq. and Percent)

Source	Gas	2013 Emission Estimate[a] (MMT CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (MMT CO_2 Eq.)		Uncertainty Range Relative to Emission Estimate[a] (%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Mobile Sources	CH_4	2.1	1.9	2.6	-13%	+21%
Mobile Sources	N_2O	18.4	16.6	22.1	-10%	+20%

[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 Approach 2 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 2013. 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

For the current Inventory, emission estimates have been revised to reflect the GWPs provided in the *IPCC Fourth Assessment Report* (AR4) (IPCC 2007). AR4 GWP values differ slightly from those presented in the *IPCC Second Assessment Report* (SAR) (IPCC 1996) (used in the previous inventories) which results in time-series recalculations for most inventory sources. Under the most recent reporting guidelines (UNFCCC 2014), countries are required to report using the AR4 GWPs, which reflect an updated understanding of the atmospheric properties of each greenhouse gas. The GWPs of CH_4 and most fluorinated greenhouse gases have increased, leading to an overall increase in CO_2-equivalent emissions from CH_4, HFCs, and PFCs. The GWPs of N_2O and SF_6 have decreased, leading to a decrease in CO_2-equivalent emissions for these greenhouse gases. The AR4 GWPs have been applied across the entire time series for consistency. For more information please see the Recalculations and Improvements Chapter.

Increases to CH_4 and N_2O emissions from mobile combustion are largely due to updates made to the Motor Vehicle Emissions Simulator (MOVES 2014) model that is used to estimate on-road gasoline vehicle distribution and mileage across the time series. Estimates of alternative fuel vehicle mileage were also revised to reflect updates made to Energy Information Administration (EIA) data on alternative fuel use and vehicle counts. In addition, the alternative fuel vehicle emissions estimates now assume a B100 biodiesel mixture (as opposed to B20, which was used for the previous Inventory report). Overall, these changes resulted in an average annual increase of 0.8 MMT CO_2 Eq. (26 percent) in CH_4 emissions and an average annual decrease of 0.4 MMT CO_2 Eq. (1 percent) in N_2O emissions from mobile combustion for the period 1990 through 2012, relative to the previous report.

Planned Improvements

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

- 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 is currently being investigated. Additionally, the feasibility of including data from a broader range of domestic and international sources for domestic bunker fuels, including data from studies such as the *Third IMO GHG Study 2014*, is being considered.
- 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. 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 60 percent of the total C consumed for non-energy purposes was stored in products, and not released to the atmosphere; the remaining 40 percent was emitted.

There are several areas in which non-energy uses of fossil fuels are closely related to other parts of this 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 and Product Use 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 adjust for the effect of net exports on the mass of C in non-energy applications.

As shown in Table 3-19, fossil fuel emissions in 2013 from the non-energy uses of fossil fuels were 119.8 MMT CO_2 Eq., which constituted approximately 2 percent of overall fossil fuel emissions. In 2013, the consumption of fuels for non-energy uses (after the adjustments described above) was 4,790.7 TBtu, an increase of 7.0 percent since 1990 (see Table 3-20). About 56.2 MMT (205.9 MMT CO_2 Eq.) of the C in these fuels was stored, while the remaining 32.7 MMT C (119.8 MMT CO_2 Eq.) was emitted.

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

Year	1990	2005	2009	2010	2011	2012	2013
Potential Emissions	312.1	377.5	307.5	325.6	316.4	315.5	325.8
C Stored	194.5	238.6	201.5	211.1	208.0	206.4	205.9
Emissions as a % of Potential	38%	37%	34%	35%	34%	34%	37%
Emissions	**117.7**	**138.9**	**106.0**	**114.6**	**108.4**	**104.9**	**119.8**

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 (2013, 2015) (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 and Product Use chapter.[54,55] 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

[54] 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.

[55] Some degree of double counting may occur between these estimates of non-energy use of fuels and process emissions from petrochemical production presented in the Industrial Processes and Produce Use sector. Data integration is not feasible at this time as feedstock data from EIA used to estimate non-energy uses of fuels are aggregated by fuel type, rather than disaggregated by both fuel type and particular industries (e.g. petrochemical production) as currently collected through EPA's GHGRP and used for the petrochemical production category.

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 (2006), 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	2009	2010	2011	2012	2013
Industry	**4,215.8**	**5,110.9**	**4,283.0**	**4,572.9**	**4,470.5**	**4,376.7**	**4,619.9**
Industrial Coking Coal	+	80.4	6.4	64.8	60.8	132.5	119.6
Industrial Other Coal	8.2	11.9	11.9	10.3	10.3	10.3	10.3
Natural Gas to Chemical Plants	281.6	260.9	220.3	298.7	297.1	292.6	296.9
Asphalt & Road Oil	1,170.2	1,323.2	873.1	877.8	859.5	826.7	783.3
LPG	1,120.5	1,610.1	1,663.9	1,834.1	1,865.8	1,886.9	2,062.0
Lubricants	186.3	160.2	134.5	149.5	141.8	130.5	138.1
Pentanes Plus	117.6	95.5	61.0	75.3	26.4	40.2	45.4
Naphtha (<401 ° F)	326.3	679.6	451.0	474.6	469.4	432.2	498.5
Other Oil (>401 ° F)	662.1	499.5	392.8	433.2	368.2	267.4	209.0
Still Gas	36.7	67.7	133.9	147.8	163.6	160.6	166.7
Petroleum Coke	27.2	105.2	108.4	+	+	+	+
Special Naphtha	100.9	60.9	44.3	25.3	21.8	14.1	96.5
Distillate Fuel Oil	7.0	11.7	17.5	5.8	5.8	5.8	5.8
Waxes	33.3	31.4	12.2	17.1	15.1	15.3	16.5
Miscellaneous Products	137.8	112.8	151.8	158.7	164.7	161.6	171.2
Transportation	**176.0**	**151.3**	**127.1**	**141.2**	**133.9**	**123.2**	**130.4**
Lubricants	176.0	151.3	127.1	141.2	133.9	123.2	130.4
U.S. Territories	**86.7**	**121.9**	**59.6**	**63.7**	**54.1**	**50.6**	**40.5**
Lubricants	0.7	4.6	1.0	1.0	1.0	1.0	1.0
Other Petroleum (Misc. Prod.)	86.0	117.3	58.5	62.7	53.1	49.5	39.4
Total	**4,478.5**	**5,384.1**	**4,469.6**	**4,777.8**	**4,658.5**	**4,550.5**	**4,790.7**

+ Does not exceed 0.05 TBtu

NA (Not applicable)

Table 3-21: 2013 Adjusted Non-Energy Use Fossil Fuel Consumption, Storage, and Emissions

Sector/Fuel Type	Adjusted Non-Energy Use[a] (TBtu)	Carbon Content Coefficient (MMT C/QBtu)	Potential Carbon (MMT C)	Storage Factor	Carbon Stored (MMT C)	Carbon Emissions (MMT C)	Carbon Emissions (MMT CO_2 Eq.)
Industry	**4,619.9**	**NA**	**85.4**	**NA**	**55.8**	**29.6**	**108.4**
Industrial Coking Coal	119.6	31.00	3.7	0.10	0.4	3.3	12.2
Industrial Other Coal	10.3	25.82	0.3	0.66	0.2	0.1	0.3
Natural Gas to Chemical Plants	296.9	14.47	4.3	0.66	2.8	1.5	5.3
Asphalt & Road Oil	783.3	20.55	16.1	1.00	16.0	0.1	0.3

LPG	2,062.0	17.06	35.2	0.66	23.3	11.9	43.7
Lubricants	138.1	20.20	2.8	0.09	0.3	2.5	9.3
Pentanes Plus	45.4	19.10	0.9	0.66	0.6	0.3	1.1
Naphtha (<401° F)	498.6	18.55	9.2	0.66	6.1	3.1	11.5
Other Oil (>401° F)	209.0	20.17	4.2	0.66	2.8	1.4	5.2
Still Gas	166.7	17.51	2.9	0.66	1.9	1.0	3.6
Petroleum Coke	0.0	27.85	0.0	0.30	0.0	0.0	0.0
Special Naphtha	96.5	19.74	1.9	0.66	1.3	0.6	2.4
Distillate Fuel Oil	5.8	20.17	0.1	0.50	0.1	0.1	0.2
Waxes	16.5	19.80	0.3	0.58	0.2	0.1	0.5
Miscellaneous Products	171.2	20.31	3.5	0.00	0.0	3.5	12.7
Transportation	**130.4**	**NA**	**2.6**	**NA**	**0.2**	**2.4**	**8.8**
Lubricants	130.4	20.20	2.6	0.09	0.2	2.4	8.8
U.S. Territories	**40.5**	**NA**	**0.8**	**NA**	**0.1**	**0.7**	**2.7**
Lubricants	1.0	20.20	0.0	0.09	0.0	0.0	0.1
Other Petroleum (Misc. Prod.)	39.4	20.00	0.8	0.10	0.1	0.7	2.6
Total	**4,790.7**		**88.9**		**56.2**	**32.7**	**119.8**

+ Does not exceed 0.05 TBtu

NA (Not applicable)

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

Note: Totals may not sum due to independent rounding. Emissions values are presented in CO_2 equivalent mass units using IPCC AR4 GWP values.

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 2015a), *Toxics Release Inventory, 1998* (2000b), *Biennial Reporting System* (EPA 2004, 2009), *Resource Conservation and Recovery Act Information System* (EPA 2013b, 2015b), pesticide sales and use estimates (EPA 1998, 1999, 2002, 2004, 2011), and the Chemical Data Access Tool (EPA 2012); the EIA Manufacturer's Energy Consumption Survey (MECS) (EIA 1994, 1997, 2001, 2005, 2010, 2013b); the National Petrochemical & Refiners Association (NPRA 2002); the U.S. Bureau of the Census (1999, 2004, 2009); Bank of Canada (2012, 2013, 2014); Financial Planning Association (2006); INEGI (2006); the United States International Trade Commission (1990-2014); Gosselin, Smith, and Hodge (1984); EPA's Municipal Solid Waste (MSW) Facts and Figures (EPA 2013a; 2014a); the Rubber Manufacturers' Association (RMA 2009, 2011, 2014); the International Institute of Synthetic Rubber Products (IISRP 2000, 2003); the Fiber Economics Bureau (FEB 2001-2013); the EPA Chemical Data Access Tool (CDAT) (EPA 2014b); and the American Chemistry Council (ACC 2003-2011, 2012, 2013, 2014a, 2014b). 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 Approach 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 *2006 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 Approach 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 2013 was estimated to be between 89.0 and 164.9 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 26 percent below to 38 percent above the 2013 emission estimate of 119.8 MMT 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: Approach 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Non-Energy Uses of Fossil Fuels (MMT CO_2 Eq. and Percent)

Source	Gas	2013 Emission Estimate (MMT CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (MMT CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Feedstocks	CO_2	73.2	48.8	122.0	-33%	67%
Asphalt	CO_2	0.3	0.1	0.6	-58%	120%
Lubricants	CO_2	18.1	14.9	21.0	-18%	16%
Waxes	CO_2	0.5	0.4	0.8	-27%	59%
Other	CO_2	27.8	16.0	30.1	-42%	8%
Total	**CO_2**	**119.8**	**89.0**	**164.9**	**-26%**	**38%**

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

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

Source	Gas	2013 Storage Factor (%)	Uncertainty Range Relative to Emission Estimate[a] (%)		(%, Relative)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Feedstocks	CO_2	66%	53%	72%	-20%	9%
Asphalt	CO_2	100%	99%	100%	0%	0%
Lubricants	CO_2	9%	4%	17%	-57%	90%
Waxes	CO_2	58%	49%	71%	-16%	22%
Other	CO_2	6%	5%	44%	-15%	607%

[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 2013. 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. Starting in 2001 through 2009, outputs exceeded inputs. In 2010 and 2011, inputs exceeded outputs, and in 2012, outputs slightly exceeded inputs. A portion of this discrepancy has been reduced (see Recalculations Discussion, below) and two strategies have been developed 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 0.61 MMT CO_2 Eq. (0.2 percent) across the entire time series. The greatest change was an increase of 7 MMT CO_2 Eq. in 2011. The 2014 Guide to the Business of Chemistry contained several new data points for 2008 through 2013, and those values were updated in this Inventory. Additionally, the Rubber Manufacturers Association released a new report with scrap tire characteristics and statistics for 2011 and 2013. Preliminary data for the 2012 Economic Census (U.S. Bureau of the Census 2014) were released which contains data on cleanser shipments in 2012. The hazardous waste data from the Biennial Report (EPA 2015b) provided updated data for 2011, which changed the hazardous waste emissions slightly. EPA's Chemical Data Access Tool (CDAT) (EPA 2014b) was the source of the production data for food additives, antifreeze, and silicones in 2012. Data were interpolated from the latest data point to 2012, to account for this new data source. Import and export data (U.S. International Trade Commission 2014) for synthetic rubber was included in the synthetic rubber stocks in the current inventory.

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 input/output discrepancies in the C mass balance contained within the NEU model. In the future, two strategies to reduce or eliminate this discrepancy will continue to be pursued. First, accounting of C in imports and exports will be improved. The import/export adjustment methodology will be examined to ensure that net exports of intermediaries such as ethylene and propylene are fully accounted for. Second, reconsider the use of top-down C input calculation in estimating emissions will be reconsidered.

Alternative approaches that rely more substantially on the bottom-up C output calculation will be considered instead.

- Response to potential changes in NEU input data. In 2013 EIA initiated implementation of new data reporting definitions for Natural Gas Liquids (NGL) and Liquefied Petroleum Gases (LPG); the new definitions may affect the characterization of the input data that EIA provides for the NEU model and may therefore result in the need for changes to the NEU methodology. EIA also obtains and applies proprietary data for LPG inputs that are not directly applied as NEU input data because the data are proprietary. The potential use of the proprietary data (in an aggregated, non-proprietary form) as inputs to the NEU model will be investigated with EIA.
- 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). A better understanding of these trends will be pursued to identify any mischaracterized or misreported fuel consumption for non-energy uses. For example, "miscellaneous products" category includes miscellaneous products that are not reported elsewhere in the EIA data set. The EIA does not have firm data concerning the amounts of various products that are being reported in the "miscellaneous products" category; however, EIA has indicated that recovered sulfur from petroleum and natural gas processing, and potentially also C black feedstock could be reported in this category. Recovered sulfur would not be reported in the NEU calculation or elsewhere in the inventory.
- Updating the average C content of solvents was researched, 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 C in solvents. Additional sources of solvents data will be identified in order to update the C content assumptions.
- Updating the average C content of cleansers (soaps and detergents) was researched; although production and consumption data for cleansers are published every 5 years by the Census Bureau, the composition (C content) of cleansers has not been recently updated. Recently available composition data sources may facilitate updating the average C content for this category.
- Revising the methodology for consumption, production, and C content of plastics was researched; because of recent changes to the type of data publicly available for plastics, the NEU model for plastics applies data obtained from personal communications. Potential revisions to the plastics methodology to account for the recent changes in published data will be investigated.
- 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, 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 analyzing C fate similar to those described in Annex 2.3 or deferring to more updated default storage factors from IPCC where available.
- Reviewing the storage of carbon black across various sectors in the Inventory; in particular, the carbon black abraded and stored in tires.

Box 3-6: Reporting of Lubricants, Waxes, and Asphalt and Road Oil Product Use in Energy Sector

The *2006 IPCC Guidelines* provides methodological guidance to estimate emissions from the first use of fossil fuels as a product for primary purposes other than combustion for energy purposes (including lubricants, paraffin waxes,

bitumen/asphalt, and solvents) under the Industrial Processes and Product Use (IPPU) sector.[56] In this Inventory, C storage and C emissions from product use of lubricants, waxes, and asphalt and road oil are reported under the Energy sector in the Carbon Emitted from Non-Energy Uses of Fossil Fuels source category (IPCC Source Category 1A).[57]

The emissions are reported in the Energy sector, as opposed to the IPPU sector, to reflect national circumstances in its choice of methodology and to increase transparency of this source category's unique country-specific data sources and methodology. The country-specific methodology used for the Carbon Emitted from Non-Energy Uses of Fossil Fuels source category is based on a carbon balance (i.e., C inputs-outputs) calculation of the aggregate amount of fossil fuels used for non-energy uses, including inputs of lubricants, waxes, asphalt and road oil (see section 3.2, Table 3-21). For those inputs, U.S. country-specific data on C stocks and flows are used to develop carbon storage factors, which are calculated as the ratio of the C stored by the fossil fuel non-energy products to the total C content of the fuel consumed, taking into account losses in the production process and during product use.[58] The country-specific methodology to reflect national circumstances starts with the aggregate amount of fossil fuels used for non-energy uses and applies a C balance calculation, breaking out the C emissions from non-energy use of lubricants, waxes, and asphalt and road oil. Due to U.S. national circumstances, reporting these C emissions separately under IPPU would involve making artificial adjustments to both the C inputs and C outputs of the non-energy use C balance. These artificial adjustments would also result in the C emissions for lubricants, waxes, and asphalt and road oil being reported under IPPU, while the C storage for lubricants, waxes, and asphalt and road oil would be reported under Energy. To avoid presenting an incomplete C balance and a less transparent approach for the Carbon Emitted from Non-Energy Uses of Fossil Fuels source category calculation, the entire calculation of C storage and C emissions is therefore conducted in the Non-Energy Uses of Fossil Fuels category calculation methodology, and both the C storage and C emissions for lubricants, waxes, and asphalt and road oil are reported under the Energy sector.

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

[56] See Volume 3: Industrial Processes and Product Use, Chapter 5: Non-Energy Products from Fuels and Solvent Use of the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC 2006).

[57] Non-methane volatile organic compound (NMVOC) emissions from solvent use are reported separately in the IPPU sector, following Chapter 5 of the *2006 IPCC Guidelines*.

[58] Data and calculations for lubricants and waxes and asphalt and road oil are in Annex 2.3: Methodology and Data for Estimating CO_2 Emissions from Fossil Fuel Combustion.

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 were incinerated in the United States in 2013 (EPA 2014). CO_2 emissions from incineration of waste rose 42 percent since 1990, to an estimated 10.1 MMT CO_2 Eq. (10,137 kt) in 2013, 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 CH_4 and N_2O emissions (De Soete 1993, IPCC 2006). CH_4 emissions from the incineration of waste were estimated to be less than 0.05 MMT CO_2 Eq. (less than 0.5 kt CH_4) in 2013, and have not changed significantly since 1990. N_2O emissions from the incineration of waste were estimated to be 0.3 MMT CO_2 Eq. (1 kt N_2O) in 2013, and have not changed significantly since 1990.

Table 3-24: CO_2, CH_4, and N_2O Emissions from the Incineration of Waste (MMT CO_2 Eq.)

Gas/Waste Product	1990	2005	2009	2010	2011	2012	2013
CO_2	**8.0**	**12.5**	**11.3**	**11.0**	**10.5**	**10.4**	**10.1**
Plastics	5.6	6.9	5.9	6.0	5.8	5.7	5.7
Synthetic Rubber in Tires	0.3	1.6	1.6	1.5	1.4	1.3	1.2
Carbon Black in Tires	0.4	2.0	1.9	1.8	1.7	1.5	1.4
Synthetic Rubber in MSW	0.9	0.8	0.7	0.7	0.7	0.7	0.7
Synthetic Fibers	0.8	1.2	1.2	1.1	1.1	1.1	1.1
CH_4	+	+	+	+	+	+	+
N_2O	**0.5**	**0.4**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**
Total	**8.4**	**12.8**	**11.6**	**11.4**	**10.9**	**10.7**	**10.4**

Note: Emissions values are presented in CO_2 equivalent mass units using IPCC AR4 GWP values.
+ Does not exceed 0.05 MMT.

Table 3-25: CO_2, CH_4, and N_2O Emissions from the Incineration of Waste (kt)

Gas/Waste Product	1990	2005	2009	2010	2011	2012	2013
CO_2	**7,972**	**12,454**	**11,295**	**11,026**	**10,550**	**10,363**	**10,137**
Plastics	5,588	6,919	5,946	5,969	5,757	5,709	5,709
Synthetic Rubber in Tires	308	1,599	1,560	1,461	1,363	1,262	1,161
Carbon Black in Tires	385	1,958	1,903	1,783	1,663	1,537	1,412
Synthetic Rubber in MSW	854	765	731	701	712	705	705
Synthetic Fibers	838	1,212	1,155	1,112	1,056	1,149	1,149
CH_4	+	+	+	+	+	+	+
N_2O	**2**	**1**	**1**	**1**	**1**	**1**	**1**

Note: Totals may not sum due to independent rounding.
+ Does not exceed 0.05 MMT.

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 3.7.

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 2014) and detailed unpublished backup data for some years not shown in the reports (Schneider 2007). For 2013, this data was assumed to be equal to that in 2012, due to the lack of available data. 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 2009 through 2013 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 2013 data (RMA 2014). Average C contents for the "Other" plastics category and synthetic rubber in municipal solid wastes were calculated from 1998 and 2002 production statistics: C content for 1990 through 1998 is based on the 1998 value; C content for 1999 through 2001 is the average of 1998 and 2002 values; and C 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 for 2011 were derived from information forthcoming in Themelis and Shin (in press) and Shin (2014). Data on total waste incinerated was not available for 2012 or 2013, so these values were assumed to equal to the 2011 value.

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* (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%
2009	270,067,786	23,674,017	8.4%
2010	271,592,991	22,714,122	8.0%
2011	273,116,704	21,741,734	7.6%
2012	273,116,704[a]	20,756,870	7.6%
2013	273,116,704[a]	20,756,870	7.6%

[a] Assumed equal to 2011 value.
Source: van Haaren et al. (2010), Themelis and Shin (in press) and Shin (2014).

Uncertainty and Time-Series Consistency

An Approach 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 Approach 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 Approach 2 quantitative uncertainty analysis are summarized in Table 3-27. Waste incineration CO_2 emissions in 2013 were estimated to be between 9.1 and 11.5 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 10 percent below to 13 percent above the 2013 emission estimate of 10.1 MMT CO_2 Eq. Also at a 95 percent confidence level, waste incineration N_2O emissions in 2013 were estimated to be between 0.2 and 1.3 MMT CO_2 Eq. This indicates a range of 50 percent below to 325 percent above the 2013 emission estimate of 0.3 MMT CO_2 Eq.

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

Source	Gas	2013 Emission Estimate (MMT CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (MMT CO_2 Eq.)		Uncertainty Range Relative to Emission Estimate[a] (%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Incineration of Waste	CO_2	10.1	9.1	11.5	-10%	+13%
Incineration of Waste	N_2O	0.3	0.2	1.3	-50%	+325%

[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 2013. 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

For the current Inventory, emission estimates have been revised to reflect the GWPs provided in the *IPCC Fourth Assessment Report* (AR4) (IPCC 2007). AR4 GWP values differ slightly from those presented in the *IPCC Second*

Assessment Report (SAR) (IPCC 1996) (used in the previous Inventories) which results in time-series recalculations for most inventory sources. Under the most recent reporting guidelines (UNFCCC 2014), countries are required to report using the AR4 GWPs, which reflect an updated understanding of the atmospheric properties of each greenhouse gas. The GWPs of CH_4 and most fluorinated greenhouse gases have increased, leading to an overall increase in CO_2-equivalent emissions from CH_4, HFCs, and PFCs. The GWPs of N_2O and SF_6 have decreased, leading to a decrease in CO_2-equivalent emissions for these greenhouse gases. The AR4 GWPs have been applied across the entire time series for consistency. For more information please see the Recalculations and Improvements chapter.

In addition, the data for synthetic rubber and carbon black in scrap tires were updated for 2010 through 2013, based on data obtained from RMA 2013 Scrap Tire Markets Report, which was released in November 2014. This update resulted in an average of a 3 percent decrease of emissions for 2010 through 2012.

The data which calculates the percent incineration was updated in the current inventory. Biocycle has not released a new State of Garbage in America Report since 2010 (with 2008 data), which used to be a semi-annual publication which publishes the results of the nation-wide MSW survey. The results of the survey have been submitted for publishing in Themelis and Shin (in press). This provided updated MSW figures for 2011, so the generation and incineration data for 2009 through 2013 are proxied to the 2011 values.

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,[59] 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 and Product Use 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 gas 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.[60] GHGRP data is available for MSW combustors, which contains information on the CO_2, CH_4, and N_2O emissions from MSW combustion, plus the fraction of the emissions that are biogenic. To calculate biogenic versus total CO_2 emissions, a default biogenic fraction of 0.6 is used. The biogenic fraction will be calculated using the current input data and assumptions to verify the current MSW emission estimates.

Additional improvements will be conducted to improve the transparency in the current reporting of waste incineration. Currently, hazardous industrial waste incineration is included within the overall calculations for the Carbon Emitted from Non-Energy Uses of Fossil Fuels category. Waste incineration activities that do not include energy recovery will also be examined.

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. While surface mines account for the majority of U.S. coal

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

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

production (see Table 3-30), underground coal mines contribute the largest share of CH_4 emissions (see Table 3-28 and Table 3-29) due to the higher CH_4 content of coal in the deeper underground coal seams. In 2013, 395 underground coal mines and 637 surface mines were operating in the U.S. Also in 2013, the U.S. was the second largest coal producer in the world (891 MMT), after China (3,561 MMT) and followed by India (613 MMT) (IEA 2014).

Underground mines liberate CH_4 from ventilation systems and from degasification systems. Ventilation systems pump air through the mine workings to dilute noxious gases and ensure worker safety; these systems can exhaust significant amounts of CH_4 to the atmosphere in low concentrations. Degasification systems are wells drilled from the surface or boreholes drilled inside the mine that remove large, often highly-concentrated, volumes of CH_4 before, during, or after mining. Some mines recover and use CH_4 generated from ventilation and degasification systems, thereby reducing emissions to the atmosphere.

Surface coal mines liberate CH_4 as the overburden is removed and the coal is exposed to the atmosphere. Methane emissions are normally a function of coal rank and depth. Surface coal mines typically produce lower rank coals and remove less than 250 feet of overburden, thus the level of emissions is much lower than from underground mines.

In addition, CH_4 is released during post-mining activities, as the coal is processed, transported and stored for use.

Total CH_4 emissions in 2013 were estimated to be 64.6 MMT CO_2 Eq. (2,584 kt CH_4), a decline of 33 percent since 1990 (see Table 3-28 and Table 3-29). Of this amount, underground mines accounted for approximately 71.6 percent, surface mines accounted for 15.0 percent, and post-mining emissions accounted for 13.4 percent.

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

Activity	1990	2005	2009	2010	2011	2012	2013
UG Mining	74.2	42.0	59.2	61.6	50.2	47.3	46.2
Liberated	80.8	59.7	78.7	85.2	71.0	65.8	65.8
Recovered & Used	(6.6)	(17.7)	(19.5)	(23.6)	(20.8)	(18.5)	(19.6)
Surface Mining	10.8	11.9	11.5	11.5	11.6	10.3	9.7
Post-Mining (Under Ground)	9.2	7.6	6.7	6.8	6.9	6.7	6.6
Post-Mining (Surface)	2.3	2.6	2.5	2.5	2.5	2.2	2.1
Total	**96.5**	**64.1**	**79.9**	**82.3**	**71.2**	**66.5**	**64.6**

Note: Emissions values are presented in CO_2 equivalent mass units using IPCC AR4 GWP values.
Note: Totals may not sum due to independent rounding. Parentheses indicate negative values.

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

Activity	1990	2005	2009	2010	2011	2012	2013
UG Mining	2,968	1,682	2,367	2,463	2,008	1,891	1,849
Liberated	3,234	2,390	3,149	3,406	2,839	2,631	2,633
Recovered & Used	(266)	(708)	(782)	(943)	(831)	(740)	(784)
Surface Mining	430	475	461	461	465	410	388
Post-Mining (UG)	368	306	267	270	276	268	263
Post-Mining (Surface)	93	103	100	100	101	89	84
Total	**3,860**	**2,565**	**3,194**	**3,293**	**2,849**	**2,658**	**2,584**

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 steps. The first step is to estimate emissions from underground mines. There are two sources of underground mine emissions: ventilation systems and degasification systems. These emissions are estimated on a mine-by-mine basis and then are summed to determine total emissions. The second step of the analysis involves estimating CH_4 emissions from surface mines and post-mining activities. In contrast to the methodology for underground mines, which uses mine-specific data, the methodology for estimating emissions from surface mines and post-mining activities consists of multiplying basin-specific coal production by basin-specific gas content and an emission factor.

Step 1: Estimate CH_4 Liberated and CH_4 Emitted from Underground Mines

Underground mines generate CH_4 from ventilation systems and from degasification systems. Some mines recover and use the generated CH_4, thereby reducing emissions to the atmosphere. Total CH_4 emitted from underground mines equals the CH_4 liberated from ventilation systems, plus the CH_4 liberated from degasification systems, minus the CH_4 recovered and used.

Step 1.1: Estimate CH_4 Liberated from Ventilation Systems

Because the U.S. Mine Safety and Health Administration (MSHA) samples CH_4 emissions from ventilation systems for all mines with detectable CH_4 concentrations[61] to ensure miner safety, these mine-by-mine measurements are used to estimate CH_4 emissions from ventilation systems. Since 2011, the EPA has also collected information on ventilation emissions from underground coal mines liberating greater than 36,500,000 actual cubic feet of CH_4 per year (about 14,700 metric tons CO_2 Eq.) through its GHGRP (EPA 2014).[62] Many of the underground coal mines reporting to EPA's GHGRP use the quarterly CH_4 emission data collected by MSHA. However, some mines use their own measurements and samples, which are taken on a quarterly basis. The 2013 ventilation emissions were calculated using the GHGRP data from the mines that take their own measurements and the MSHA data for all other mines.

Step 1.2: Estimate CH_4 Liberated from Degasification Systems

Some gassier underground mines also use degasification systems (e.g., wells or boreholes) to remove CH_4 before, during, or after mining. This CH_4 can then be collected for use or vented to the atmosphere. Several data sets were used to estimate the quantity of CH_4 collected by each of the twenty-four mines using degasification systems in 2013. For Alabama mines that sold recovered CH_4 to a pipeline, pipeline sales data published by state petroleum and natural gas agencies were used to estimate degasification emissions. The well data was also used to estimate CH_4 collected from mined-through pre-drainage wells. For most other mines that either sold CH_4 to a pipeline, used CH_4 on site, or vented CH_4 from degasification systems, data on degasification emissions reported to the EPA's GHGRP (EPA 2014) were used.

Step 1.3: Estimate CH_4 Recovered from Degasification Systems and Utilized (Emissions Avoided)

Finally, the amount of CH_4 recovered by degasification and ventilation systems and then used (i.e., not vented) was estimated. In 2013, fifteen active coal mines had CH_4 recovery and use projects, of which thirteen mines sold the recovered CH_4 to a pipeline. One of the mines that sold gas to a pipeline also used CH_4 to fuel a thermal coal dryer. One mine used recovered CH_4 for electrical power generation, and two other mines used recovered CH_4 to heat mine ventilation air or dry coal. Emissions avoided as a result of pipeline sales projects at Alabama and West Virginia mines were estimated using gas sales data reported by the state agencies. For all other mines with pipeline sales or used methane for electric power or heating, either the coal mine operators or project developers supplied information regarding methane recovery or GHGRP data were used.

Step 2: Estimate CH_4 Emitted from Surface Mines and Post-Mining Activities

Mine-specific data were not available for estimating CH_4 emissions from surface coal mines or for post-mining activities. For surface mines, basin-specific coal production obtained from the Energy Information Administration's Annual Coal Report (see Table 3-30) (EIA 2014) was multiplied by basin-specific gas contents and a 150 percent emission factor (to account for CH_4 from over- and under-burden) to estimate CH_4 emissions. The emission factor was revised downward in 2012 from 200 percent, based on more recent studies in Canada and Australia (King 1994, Saghafi 2013). The 150 percent emission factor was applied to all inventory years since 1990, retroactively. For post-mining activities, basin-specific coal production was multiplied by basin-specific gas contents and a 32.5

[61] 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.

[62] Underground coal mines report to EPA under Subpart FF of the program.

percent emission factor for CH_4 desorption during coal transportation and storage (Creedy 1993). Basin-specific *in situ* gas content data was compiled from AAPG (1984) and USBM (1986). Beginning in 2006, revised data on *in situ* CH_4 content and emission factors have been taken from EPA (1996) and EPA (2005).

Table 3-30: Coal Production (kt)

Year	Underground	Surface	Total
1990	384,244	546,808	931,052
2005	334,398	691,448	1,025,846
2009	301,241	671,475	972,716
2010	305,862	676,177	982,039
2011	313,529	684,807	998,337
2012	310,608	610,307	920,915
2013	309,546	581,270	890,815

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis was conducted for the coal mining source category using the IPCC-recommended Approach 2 uncertainty estimation methodology. Because emission estimates from underground ventilation systems were based on actual measurement data from MSHA or EPA's GHGRP, 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 & Wang 2000). GHGRP data was used for a number of the mines beginning in 2013, however, the equipment uncertainty is applied to both MSHA and GHGRP data.

Estimates of CH_4 recovered by degasification systems are relatively certain for utilized CH_4 because of the availability of gas sales information. In addition, many coal mine operators provided information on mined-through dates for pre-drainage wells. Many of the recovery estimates use data on wells within 100 feet of a mined area. However, uncertainty 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 estimated.

Continuous CH_4 monitoring is required of mines that report utilized methane on or off-site to EPA's GHGRP. Beginning in 2013, use of GHGRP data for mines without publicly-available gas usage or sales records has reduced the uncertainty from previous estimations. In addition, since 2012, GHGRP data has been used to estimate CH_4 emissions from vented degasification wells, thus reducing the uncertainty associated with that subsource.

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 Approach 2 quantitative uncertainty analysis are summarized in Table 3-31. Coal mining CH_4 emissions in 2013 were estimated to be between 56.6 and 74.7 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 12.4 percent below to 15.6 percent above the 2013 emission estimate of 64.6 MMT CO_2 Eq.

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

Source	Gas	2013 Emission Estimate (MMT CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (MMT CO_2 Eq.)		Uncertainty Range Relative to Emission Estimate[a] (%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Coal Mining	CH_4	64.6	56.6	74.7	-12.4%	+15.6%

Note: Emissions values are presented in CO_2 equivalent mass units using IPCC AR4 GWP values.
[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 2013. Details on the emission trends through time are described in more detail in the Methodology section.

Recalculations Discussion

For the current Inventory, emission estimates have been revised to reflect the GWPs provided in the *IPCC Fourth Assessment Report* (AR4) (IPCC 2007). AR4 GWP values differ slightly from those presented in the *IPCC Second Assessment Report* (SAR) (IPCC 1996) (used in the previous inventories) which results in time-series recalculations for most inventory sources. Under the most recent reporting guidelines (UNFCCC 2014), countries are required to report using the AR4 GWPs, which reflect an updated understanding of the atmospheric properties of each greenhouse gas. The GWPs of CH_4 and most fluorinated greenhouse gases have increased, leading to an overall increase in CO_2-equivalent emissions from CH_4. The GWPs of N_2O and SF_6 have decreased, leading to a decrease in CO_2-equivalent emissions for these greenhouse gases. The AR4 GWPs have been applied across the entire time series for consistency. For more information please see the Recalculations and Improvements Chapter.

Prior to the current Inventory, vented degasification emissions from underground coal mines were typically estimated based on drainage efficiencies reported by either the mining company or MSHA. However, beginning in 2011, underground coal mines began reporting CH_4 emissions from degasification systems to EPA under its GHGRP, which requires degasification quantities to be measured weekly, thus offering a more accurate account than previous methods. As a result, data reported to EPA's GHGRP in 2012 and 2013 were used to estimate vented degasification volumes for those mines. GHGRP data was also used in 2013 for degas-used volumes at mines using methane on-site or without available gas sales records. In addition, for forty-nine mines, the 2013 VAM emission estimates included VAM data measured at least quarterly and reported to the GHGRP. Emissions avoided at mines with VAM mitigation projects (2) were estimated based on emission reductions registered at the Climate Action Reserve GHG Registry (CAR 2014).

Planned Improvements

Future improvements to the Coal Mining category will include continued analysis and integration into the national inventory of the degasification quantities and ventilation emissions data reported by underground coal mines to EPA's GHGRP. A higher reliance on the GHGRP will provide greater consistency and accuracy in future inventories. MSHA data will serve as a quality assurance tool for validating GHGRP data. Reconciliation of the GHGRP and Inventory data sets are still in progress. In implementing improvements and integrating 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 (IPCC 2011).

3.5 Abandoned Underground Coal Mines (IPCC Source Category 1B1a)

Underground coal mines contribute the largest share of coal mine methane (CMM) 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, 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.

Annual gross abandoned mine CH_4 emissions ranged from 7.2 to 10.8 MMT CO_2 Eq. from 1990 through 2013, varying, in general, by less than 1 percent 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 (10.8 MMT CO_2 Eq.) due to the large number of mine closures from 1994 to 1996 (72 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. Since 2002, there have been fewer than twelve gassy mine closures each year. There were eight gassy mine closures in 2013. In 2013, gross abandoned mine emissions decreased slightly to 8.8 MMT CO_2 Eq. (see Table 3-32 and Table 3-33). Gross emissions are reduced by CH_4 recovered and used at 37 mines, resulting in net emissions in 2013 of 6.2 MMT CO_2 Eq.

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

Activity	1990	2005	2009	2010	2011	2012	2013
Abandoned Underground Mines	7.2	8.4	9.9	9.7	9.3	8.9	8.8
Recovered & Used	+	1.8	3.6	3.2	2.9	2.7	2.6
Total	**7.2**	**6.6**	**6.4**	**6.6**	**6.4**	**6.2**	**6.2**

Note: Emissions values are presented in CO_2 equivalent mass units using IPCC AR4 GWP values.
+ Does not exceed 0.05 MMT CO_2 Eq.
Note: Totals may not sum due to independent rounding.

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

Activity	1990	2005	2009	2010	2011	2012	2013
Abandoned Underground Mines	288	334	398	389	373	358	353
Recovered & Used	+	70	143	126	116	109	104
Total	**288**	**264**	**254**	**263**	**257**	**249**	**249**

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

Methodology

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

In order to estimate CH_4 emissions over time for a given abandoned 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's characteristics. The emission rate declines because the mine pressure (Pw) is essentially constant at atmospheric pressure for a vented mine, and the productivity index (PI), which is expressed as the flow rate per unit of pressure change, is essentially constant at the pressures of interest (atmospheric to 30 psia). The CH_4 flow rate is determined by the laws of gas flow through porous media, such as Darcy's Law. A rate-time equation can be generated that can be used to predict future emissions. This decline through time is hyperbolic in nature and can be empirically expressed as:

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

where,

- q = Gas flow rate at time t in million cubic feet per day (mmcfd)
- q_i = Initial gas flow rate at time zero (t_o), 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 2004).

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 flooded 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 2004).

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

where,

- q = Gas flow rate at time t in mmcfd
- qi = Initial gas flow rate at time zero (to), mmcfd
- D = Decline rate, 1/yr
- t = Elapsed time from to (years)

Seals have an inhibiting effect on the rate of flow of CH_4 into the atmosphere compared to the flow rate that would exist if the mine had an open vent. The total volume emitted will be the same, but emissions will occur over a longer period of time. The methodology, therefore, treats the emissions prediction from a sealed mine similarly to the emissions prediction from a vented mine, but uses a lower initial rate depending on the degree of sealing. A computational fluid dynamics simulator was 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 2004).

For active coal mines, those mines producing over 100 thousand cubic feet per day (mcfd) account for 98 percent of all CH_4 emissions. This same relationship is assumed for abandoned mines. It was determined that the 492 abandoned mines closed after 1972 produced emissions greater than 100 mcfd when active. Further, the status of 283 of the 492 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 whose status is unknown were placed in one of these three categories by applying a probability distribution analysis based on the known status of other mines located in the same coal basin (EPA 2004).

Table 3-34: Number of Gassy Abandoned Mines Present in U.S. Basins, grouped by Class according to Post-Abandonment State

Basin	Sealed	Vented	Flooded	Total Known	Unknown	Total Mines
Central Appl.	33	25	48	106	137	243
Illinois	32	3	14	49	27	76
Northern Appl.	42	22	16	80	36	116
Warrior Basin	0	0	16	16	0	16
Western Basins	27	3	2	32	9	41
Total	**134**	**53**	**96**	**283**	**209**	**492**

Inputs to the decline equation require the average emission rate and the date of abandonment. Generally this data is available for mines abandoned after 1971; however, such data are largely unknown for mines closed before 1972. Information that is readily available, such as coal production by state and county, is helpful but does not provide enough data to directly employ the methodology used to calculate emissions from mines abandoned before 1972. It is assumed that pre-1972 mines are governed by the same physical, geologic, and hydrologic constraints that apply to post-1971 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 the 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 2004).

Abandoned mine 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 vented to determine the total CH_4 liberation rate for all mines that closed between 1992 and 2013. Since the sample of gassy mines (with active mine emissions greater than 100 mcfd) is assumed to account for 78 percent of the pre-1972 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 2013, 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 from 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 rather 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 Approach 2 quantitative uncertainty analysis are summarized in Table 3-35. Annual abandoned coal mine CH_4 emissions in 2013 were estimated to be between 5.0 and 7.7 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 20 percent below to 24 percent above the 2013 emission estimate of 6.2 MMT CO_2 Eq. One of the reasons for the relatively narrow range is that mine-specific data is available for use in the methodology for mines closed after 1972. Emissions from mines closed prior to 1972 have the largest degree of uncertainty because no mine-specific CH_4 liberation rates exist.

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

Source	Gas	2013 Emission Estimate (MMT CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (MMT CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Abandoned Underground Coal Mines	CH_4	6.2	5.0	7.7	-20%	+24%

[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 2013. Details on the emission trends through time are described in more detail in the Methodology section, above.

3.6 Petroleum Systems (IPCC Source Category 1B2a)

Methane emissions from petroleum systems are primarily associated with onshore and offshore 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. Total CH_4 and CO_2 emissions from petroleum systems in 2013 were 25.2 MMT CO_2 Eq. (1,009 kt CH_4)[63] and 6.0 MMT CO_2 Eq. (6,001 kt), respectively. Since 1990, CH_4 emissions have decreased by 20 percent. The net decrease is due mainly to increasing voluntary reductions through Natural Gas STAR in the production segment. From 2012 to 2013, CH_4 emissions increased 8 percent, due mainly to increases in tank venting and pneumatic controller vents. CO_2 emissions have increased by 35 percent since 1990, and 19 percent from 2012 to 2013, due to increased domestic production, with the largest increases occurring in crude refining CO_2 emissions.

Production Field Operations. Production field operations account for 96 percent of total CH_4 emissions from petroleum systems. Vented CH_4 from field operations account for approximately 79 percent of the emissions from the production sector, uncombusted CH_4 emissions (i.e. unburned fuel) account for 11 percent, fugitive emissions are 9 percent, and process upset emissions are approximately 0.3 percent. The most dominant sources of emissions, in order of magnitude, are high bleed pneumatic controllers, oil tanks, shallow water offshore oil platforms, low bleed pneumatic controllers, gas engines, oil wellheads (light crude services), and chemical injection pumps,. These seven sources alone emit 90 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

[63] The CH_4 emission estimate for 2013 for petroleum systems decreased by approximately 15 MMT CO_2 Eq. from the value presented in the public review draft. This change is largely due to a decrease in the number of pneumatic controllers calculated for the petroleum production segment and an increase in the Natural Gas STAR emissions reductions allocated to petroleum systems (correction of a spreadsheet error noted in the public review draft). For more information, please see Recalculations Discussion.

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 estimated 25 percent of such pumps that use associated gas to drive pneumatic pumps. The remaining 6 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.

Since 1990, CH_4 emissions from production of crude oil have decreased by 21 percent. This net decrease is due mainly to increasing voluntary reductions through Natural Gas STAR in the production segment.

Vented CO_2 associated with production field operations account for approximately 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 CO_2 emissions are oil tanks, high bleed pneumatic controllers, shallow water offshore oil platforms, low bleed pneumatic controllers, and oil wellheads (light crude services). These five sources together account for slightly over 98 percent of the non-combustion CO_2 emissions from production field operations, while the remaining 1 percent of the emissions is distributed among 24 additional activities within the three categories: vented, fugitive, and process upsets. Note that CO_2 from associated gas flaring is accounted in natural gas systems production emissions. CO_2 emissions from flaring for both natural gas and oil were 16 MMT CO_2 Eq. in 2013.

Crude Oil Transportation. Crude oil transportation activities account for approximately 0.7 percent of total CH_4 emissions from the oil industry. Venting from tanks, truck loading, rail loading, and marine vessel loading operations account for 82 percent of CH_4 emissions from crude oil transportation. Fugitive emissions, almost entirely from floating roof tanks, account for 14 percent of CH_4 emissions from crude oil transportation. The remaining 4 percent is distributed among two additional sources within the vented emissions category (i.e., pump station maintenance and pipeline pigging). Emissions from pump engine drivers and heaters were not estimated due to lack of data.

Since 1990, CH_4 emissions from transportation have increased by almost 4 percent. However, because emissions from crude oil transportation account for such a small percentage of the total emissions from the petroleum industry, this has had little impact on the overall emissions. Methane emissions have increased by approximately 11 percent from 2012 levels.

Crude Oil Refining. Crude oil refining processes and systems account for slightly above 3 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, combustion emissions account for about 60 percent of the CH_4 emissions, while vented and fugitive emissions account for approximately 26 and 13 percent, respectively. Flare emissions are the primary combustion emissions contributor. Refinery system blowdowns for maintenance and process vents are the primary venting contributors. Most of the fugitive CH_4 emissions from refineries are from equipment leaks and storage tanks.

CH_4 emissions from refining of crude oil have increased by approximately 24 percent since 1990; however, similar to the transportation subcategory, this increase has had little effect on the overall emissions of CH_4. Since 1990, CH_4 emissions have fluctuated between 27 and 34 kt.

Flare emissions from crude oil refining accounts for 95 percent of the total CO_2 emissions in petroleum systems. Refinery CO_2 emissions increased by 36 percent from 1990 to 2013.

Table 3-36: CH_4 Emissions from Petroleum Systems (MMT CO_2 Eq.)

Activity	1990	2005	2009	2010	2011	2012	2013
Production Field Operations (Potential)	**30.8**	**25.1**	**26.3**	**26.9**	**27.6**	**29.6**	**31.3**
Pneumatic controller venting[a]	12.2	10.1	10.6	10.8	11.1	11.6	11.9
Tank venting	6.3	4.7	5.0	5.3	5.5	6.7	7.9
Combustion & process upsets	2.9	2.3	2.4	2.5	2.5	2.7	2.8
Misc. venting & fugitives	7.9	6.9	7.0	7.1	7.1	7.2	7.2
Wellhead fugitives	1.5	1.2	1.3	1.3	1.4	1.5	1.5
Production Voluntary Reductions	(0.1)	(2.6)	(5.7)	(6.4)	(6.6)	(7.3)	(7.1)

Production Field Operations (Net)	**30.8**	**22.6**	**20.6**	**20.6**	**21.1**	**22.3**	**24.2**
Crude Oil Transportation	**0.2**	**0.1**	**0.1**	**0.1**	**0.1**	**0.2**	**0.2**
Refining	**0.7**	**0.8**	**0.7**	**0.7**	**0.8**	**0.8**	**0.8**
Total	**31.5**	**23.5**	**21.5**	**21.3**	**22.0**	**23.3**	**25.2**

Note: Emissions values are presented in CO_2 equivalent mass units using IPCC AR4 GWP values.
Note: Totals may not sum due to independent rounding.
[a] Values presented in this table for pneumatic controllers are potential emissions. Net emissions from pneumatic controllers are presented in the Recalculations Discussion.

Table 3-37: CH_4 Emissions from Petroleum Systems (kt)

Activity	1990	2005	2009	2010	2011	2012	2013
Production Field Operations (Potential)	**1,230**	**1,006**	**1,053**	**1,077**	**1,106**	**1,184**	**1,253**
Pneumatic controller venting[a]	489	405	425	433	443	463	474
Tank venting	250	187	202	210	222	267	317
Combustion & process upsets	115	91	95	98	101	107	113
Misc. venting & fugitives	317	275	279	282	284	287	289
Wellhead fugitives	58	47	52	54	56	59	60
Production Voluntary Reductions	(3)	(103)	(227)	(255)	(263)	(290)	(285)
Production Field Operations (Net)	**1,227**	**903**	**826**	**822**	**843**	**893**	**969**
Crude Oil Transportation	**7**	**5**	**5**	**5**	**5**	**6**	**7**
Refining	**27**	**31**	**29**	**27**	**30**	**32**	**34**
Total	**1,261**	**939**	**860**	**854**	**878**	**931**	**1,009**

Note: Totals may not sum due to independent rounding.
[a] Values presented in this table for pneumatic controllers are potential emissions. Net emissions from pneumatic controllers are presented in the Recalculations Discussion.

Table 3-38: CO_2 Emissions from Petroleum Systems (MMT CO_2 Eq.)

Activity	1990	2005	2009	2010	2011	2012	2013
Production Field Operations	**0.4**	**0.3**	**0.3**	**0.3**	**0.3**	**0.4**	**0.5**
Pneumatic controller venting	+	+	+	+	+	+	+
Tank venting	0.3	0.2	0.3	0.3	0.3	0.4	0.4
Misc. venting & fugitives	+	+	+	+	+	+	+
Wellhead fugitives	+	+	+	+	+	+	+
Process upsets	+	+	+	+	+	+	+
Crude Refining	**4.1**	**4.6**	**4.4**	**3.8**	**4.1**	**4.7**	**5.5**
Total	**4.4**	**4.9**	**4.7**	**4.2**	**4.5**	**5.1**	**6.0**

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

Table 3-39: CO_2 Emissions from Petroleum Systems (kt)

Activity	1990	2005	2009	2010	2011	2012	2013
Production Field Operations	**375**	**285**	**305**	**317**	**333**	**394**	**461**
Pneumatic controller venting	27	23	24	24	25	26	26
Tank venting	328	246	265	276	291	351	417
Misc. venting & fugitives	16	13	14	14	14	14	14
Wellhead fugitives	3	3	3	3	3	3	3
Process upsets	0.2	0.1	0.1	0.2	0.2	0.2	0.2
Crude Refining	**4,070**	**4,620**	**4,351**	**3,836**	**4,134**	**4,666**	**5,540**
Total	**4,445**	**4,904**	**4,656**	**4,153**	**4,467**	**5,060**	**6,001**

Note: Totals may not sum due to independent rounding.

Methodology

The methodology for estimating CH_4 emissions from petroleum systems is based on comprehensive studies of CH_4 emissions from U.S. petroleum systems (GRI/EPA 1996, EPA 1999) and EPA's GHGRP data. The 1996 and 1999 studies calculated emission estimates for 57 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 13 for refining operations. Annex 3.5 provides greater detail on the emission estimates for these 57 activities. The estimates of CH_4 emissions from petroleum systems do not include emissions downstream of oil refineries because these emissions are negligible.

Key references for activity data and emission factors are DrillingInfo (2014), the Energy Information Administration annual and monthly reports (EIA 1990 through 2014), (EIA 1995 through 2014a, 2014b, 2014c), "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 and BOEM reports (BOEMRE 2004, BOEM 2011), analysis of BOEMRE data (EPA 2005, BOEMRE 2004), the Oil & Gas Journal (OGJ 2014a, 2013b), the Interstate Oil and Gas Compact Commission (IOGCC 2011), the United States Army Corps of Engineers, (1995-2012), and the GHGRP (2010-2013).

The methodology for estimating CH_4 emissions from the 46 oil industry activities (excluding refining activities) employs emission factors initially developed by EPA (1999). Activity data for the years 1990 through 2013 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 for all federal offshore platforms (EPA 2015, BOEM 2014). 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 2013. 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 (BOEM) (formerly Bureau of Ocean Energy Management, Regulation, and Enforcement [BOEMRE]) datasets (BOEM 2011a,b,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 2011).

For some years, complete activity data were not available. In such cases, one of three approaches was employed. Where appropriate, the activity data were 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 were held constant from 1990 through 2013 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.

For petroleum refining activities, 2010 to 2013 emissions were directly obtained from EPA's GHGRP. All refineries are required to report their CH_4 and CO_2 emissions for all major activities since 2010. The national totals of these

emissions for each activity were used for the 2010 to 2013 emissions. The national emission totals for each activity were also divided by refinery feed rates for those four Inventory years to develop average activity-specific emission factors. These emission factors were used to estimate national emissions for each refinery activity from 1990 to 2009 based on national refinery feed rates for the respective Inventory year. (EPA 2015c).

The Inventory estimate for Petroleum Systems takes into account Natural Gas STAR reductions. Voluntary reductions included in the Petroleum Sector calculations were those reported to Natural Gas STAR for the following activities: artificial lift: gas lift; artificial lift: use compression; artificial lift: use pumping unit; consolidate crude oil production and water storage tanks; lower heater-treater temperature; re-inject gas for enhanced oil recovery; re-inject gas into crude; and route casinghead gas to vapor recovery unit or compressor. In addition, a portion of the total Gas STAR reductions from pneumatic controllers in the production sector are applied to potential emissions in the petroleum sector.

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 three activities from petroleum refining. For the production field operations, emissions are estimated for each activity by multiplying emission factors by their corresponding activity data. The emission factors for CO_2 are generally estimated by multiplying the CH_4 emission factors by a conversion factor, which is the ratio of CO_2 content and CH_4 content in produced associated gas. One exception 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). Other exceptions to this methodology are the three petroleum refining activities (i.e., flares, asphalt blowing, and process vents); the CO_2 emissions data for 2010 to 2013 were directly obtained from the GHGRP. The 2010 to 2013 CO_2 emissions GHGRP data along with the refinery feed data for 2010 to 2013 were used to derive CO_2 emission factors (i.e., sum of activity emissions/sum of refinery feed). The emission factors were then applied to the annual refinery feed to estimate CO_2 emissions for 1990 to 2009.

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis was conducted in 2010 to determine the level of uncertainty surrounding estimates of emissions from petroleum systems using the IPCC-recommended Approach 2 methodology (Monte Carlo Simulation technique). The @RISK software model was used to quantify the uncertainty associated with the emission estimates using the 7 highest-emitting sources ("top 7 sources") for the year 1995. The @RISK 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 IPCC guidance notes that in using this method, "some uncertainties that are not addressed by statistical means may exist, including those arising from omissions or double counting, or other conceptual errors, or from incomplete understanding of the processes that may lead to inaccuracies in estimates developed from models." As a result, the understanding of the uncertainty of emission estimates for this category evolves and improves as the underlying methodologies and datasets improve.

The uncertainty analysis conducted in 2010 has not yet been updated for the 1990 through 2013 Inventory years; instead, the uncertainty percentage ranges calculated previously were applied to 2013 emission estimates. The majority of sources in the current Inventory were calculated using the same emission factors and activity data for which PDFs were developed in the 1990 through 2009 uncertainty analysis. As explained in the Methodology section above and the Recalculations Discussion below, several emission sources have undergone recent methodology revisions, and the 2009 uncertainty ranges will not reflect the uncertainty associated with the recently revised emission factors and activity data sources. Please see discussion on Planned Improvements.

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 2013, based on the previously conducted uncertainty assessment using the recommended IPCC methodology. The heterogeneous nature of the petroleum industry makes it difficult to sample facilities that are completely representative of the entire industry. Additionally, highly variable emission rates were measured among many system components, making the calculated average emission rates uncertain. The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-40. Petroleum systems CH_4 emissions in 2013 were estimated to be between 19.2 and 62.8 MMT CO_2 Eq., while CO_2 emissions were estimated to be between 4.6 and 14.9 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 24 percent below to 149 percent above the 2013 emission estimates of 25.2 and 6.0 MMT CO_2 Eq. for CH_4 and CO_2, respectively.

Table 3-40: Approach 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Petroleum Systems (MMT CO_2 Eq. and Percent)

Source	Gas	2013 Emission Estimate (MMT CO_2 Eq.)[b]	Uncertainty Range Relative to Emission Estimate[a] (MMT CO_2 Eq.)		(%)	
			Lower Bound[b]	Upper Bound[b]	Lower Bound[b]	Upper Bound[b]
Petroleum Systems	CH_4	25.2	19.2	62.8	-24%	149%
Petroleum Systems	CO_2	6.0	4.6	14.9	-24%	149%

[a] Range of 2013 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 2013. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification Discussion

The petroleum system emission estimates in the Inventory are continually being reviewed and assessed to determine whether emission factors and activity factors accurately reflect current industry practices. A QA/QC analysis was performed for data gathering and input, documentation, and calculation. QA/QC checks are consistently conducted to minimize human error in the model calculations. EPA performs a thorough review of information associated with new studies, GHGRP data, regulations, public webcasts, and the Natural Gas STAR Program to assess whether the assumptions in the Inventory are consistent with current industry practices. In addition, EPA receives feedback through annual expert and public review period. Feedback received is noted in the Recalculations and Planned Improvement sections.

Recalculations Discussion

For the current Inventory, emission estimates have been revised to reflect the GWPs provided in the *IPCC Fourth Assessment Report* (AR4) (IPCC 2007). AR4 GWP values differ slightly from those presented in the *IPCC Second Assessment Report* (SAR) (IPCC 1996) (used in the previous inventories) which results in time-series recalculations for most Inventory sources. Under the most recent reporting guidelines (UNFCCC 2014), countries are required to report using the AR4 GWPs, which reflect an updated understanding of the atmospheric properties of each greenhouse gas. The GWPs of CH_4 and most fluorinated greenhouse gases have increased, leading to an overall increase in calculated CO_2-equivalent emissions from CH_4, HFCs, and PFCs. The GWPs of N_2O and SF_6 have decreased, leading to a decrease in calculated CO_2 equivalent emissions for these greenhouse gases. The AR4 GWPs have been applied across the entire time series for consistency. For more information please see the Recalculations and Improvements Chapter.

EPA received information and data related to the emission estimates through the Inventory preparation process, previous Inventories' formal public notice periods, GHGRP data, and new studies. EPA carefully evaluated relevant information available, and made several updates, such as updates to offshore platforms, pneumatic controllers, refineries, and well count data. In addition, revisions to use the latest activity data resulted in changes to emissions for several sources.

Methodological changes made in the current (2015) Inventory are described below.

The net impacts of the changes (comparing 2012 estimate from the previous (2014) Inventory and current (2015) Inventory) are a decrease in CH_4 emissions of around 14.5 MMT CO_2 Eq., or 38 percent, and an increase in CO_2

emissions of around 6 MMT CO_2, or 1,400 percent.[64] Recalculations in the offshore petroleum platforms estimates resulted in a large decrease in 2012 the CH_4 emission estimate from this source in the production segment, from 15.2 MMT CO_2 Eq. in the 2014 Inventory, to 4.7 MMT CO_2 Eq. in the current (2015) Inventory. Recalculations to the onshore petroleum production emissions estimates resulted in a small decrease in the 2012 CH_4 emission estimate for onshore sources, from 22.0 MMT CO_2 Eq. in the previous (2014) Inventory, to 19.5 MMT CO_2 Eq. in the current (2015) Inventory. Methane emission estimates for other segments (i.e., refining and transport) changed by around 0.5 percent. The increase in the CO_2 emissions estimates is due to the update to the petroleum refineries calculations.

Across the 1990-2012 time series, compared to the previous (2014) Inventory, in the current (2015) Inventory, the CH_4 emission estimate decreased by 11.8 MMT CO_2 Eq. on average (or 32 percent), and the CO_2 emission estimate increased by 4.4 MMT CO_2 on average (or around 1,300 percent).

Offshore Platforms

The U.S. Department of the Interior (DOI) began inventorying offshore platform greenhouse gas emissions in the Bureau of Ocean Energy Management's (BOEM) Gulf Offshore Activity Data System (GOADS) in 2000 with subsequent revisions in 2005, 2008, and 2011. The original year 2000 GOADS data were used to develop the emission factors used in the previous GHG Inventory calculations. There have been significant improvements in GOADS data collection and processing since 2000. For the final version of the 1990-2013 Inventory, the 2011 GOADS data were used to revise the emission factors used to calculate offshore oil and gas emissions in the Inventory. The platforms in GOADS were separated into the four categories used in the Inventory methodology: oil versus gas platforms and deep water versus shallow water platforms. Then, the reported emissions for each platform group were used to develop average platform emission factors for Natural Gas Systems and Petroleum Systems. EPA is in the process of calculating emission factors based on the 2005 and 2008 GOADS data that will be applied to years in the time series on either side of the GOADS inventory year that provides the emission factors. Updated activity data were also sought for oil and gas offshore platforms, as the current Inventory activity data is based on DOI 2010 data. At this time no new references were identified that provide current year (2013) and historic platform counts, on a consistent basis. For the year 2012, this revision results in a decrease in CH_4 of 9 MMT CO_2 Eq., or 69 percent and a decrease in CO_2 of >0.1 MMT CO_2, or 24 percent.[65] Commenters on the public review draft supported this update, and recommended that EPA improve its activity data for the number of platforms by using Lexco/OWL, and that EPA improve data on flaring of offshore gas, for example, by reviewing platform data to determine which platforms have a flare.

Well Counts and Completion and Workover Counts

In previous Inventories, data on well counts for petroleum systems were from EIA, while well count data for natural gas systems came from DrillingInfo. In the current GHG Inventory, the time series has been updated to use data from DrillingInfo (HPDI) for producing oil well counts.

The update resulted in an increase in the number of producing oil well counts, which increased calculated potential emissions from sources relying on this activity data. The activity data for many emission sources such as pneumatics, pumps, compressors, separators, and heater treaters are scaled from the 1992 base year, in part based on the ratio of oil well count in a given year to the count of oil wells in 1992. While oil well counts increased by nearly 50 percent on average across all Inventory years, the differential between 1992 and 2012 also slightly increased, leading to an increase in activity data of approximately 6 percent for these sources. For example, the increase in the number of oil wells resulted in an increase in the number of pneumatic controllers estimated in petroleum systems, from around 415,000 for 2012 in the previous Inventory, to around 440,000 in the final current (2015) Inventory.

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[64] Additional information on recent changes to the Inventory can be found at <http://www.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>

[65] For additional information, please see memo "Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2013: Revision to Offshore Platform Emissions." EPA (2015b) available at <http://www.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>

[66,67] Activity data for other emission sources such fugitives from wellheads and headers are calculated by applying activity factors to the count of oil wells; due to the increase in oil well counts for all Inventory years, the activity data for these sources increased by approximately 50 percent up to 150 percent.

Pneumatic Controllers

In previous Inventories, all production segment reductions related to pneumatic controllers that were reported to Natural Gas STAR were assigned to the natural gas systems category. Since some portion of these reductions would be more appropriately assigned to the petroleum systems category, in the final version of the current Inventory, the production segment reductions related to pneumatic controllers have been allocated to the natural gas and petroleum systems categories based upon the calculated potential emissions for pneumatic controllers in each source category. EPA calculated the fraction of potential emissions from pneumatic controllers in petroleum systems out of the total potential pneumatic controller emissions from both natural gas and petroleum systems. On average across all Inventory years, potential pneumatic controller emissions from petroleum systems make up 35 percent of total potential pneumatic controller emissions from both source categories. EPA then applied the year-specific potential emissions fraction to the reported Natural Gas STAR pneumatic controller reductions and allocated that portion of the reductions to the natural gas systems source category. This update decreases net CH_4 emissions by as little as <0.1 MMT CO_2 Eq. in 1990 (1 percent of potential emissions), but reported reductions increase over time such that in 2013 the decrease is 6.3 MMT CO_2 Eq. (over 50 percent of potential emissions). Reviewers supported apportioning the Gas STAR reductions to both oil and gas.

Table 3-41: Pneumatic Controllers Activity Data and Emissions

Data Element	1990	2000	2005	2010	2012	2013
# of Pneumatic Controllers	466,603	395,557	386,058	412,712	441,311	452,170
Calculated Potential Methane (kt)	489	415	405	433	463	474
Natural Gas STAR Reductions (kt)	3	42	67	195	245	254
Net Emissions (kt)	**487**	**373**	**338**	**238**	**218**	**221**

Petroleum Refineries

The calculations for the refineries portion of petroleum systems were revised to use data available from GHGRP subpart Y. All refineries have been reporting to the GHGRP since 2010. For petroleum refining activities, 2010 through 2013 emissions were directly obtained from EPA's GHGRP and used for these years in the Inventory time series. Since GHGRP data only cover recent years of the Inventory time series, an extrapolation approach was employed to develop consistent emissions estimates back to 1990. Publicly available throughput data from DOE/EIA (i.e., refinery feed data from DOE/EIA's Petroleum Supply Annual) were used to scale GHGRP emissions to reflect activity in earlier years. The national emission totals for each activity over the period 2010 through 2013 were divided by total refinery feed rate during 2010 through 2013 to develop average activity-specific emission factors. These emission factors were used to estimate national emissions for each refinery activity from 1990 to 2009 based on national refinery feed rates for the respective Inventory year. The impact of this improvement resulted in an increase in emissions across the time series. For the year 2012, this revision results in an increase in

[66] For additional information, please see memo "Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2013: Revision to Data Source for Well Counts." EPA (2015a) available at <http://www.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>

[67] The estimate for the number in pneumatic controllers in the petroleum production segment for 2013 decreased 38 percent from the public review draft of the 2015 Inventory to the final 2015 Inventory. This was due to correcting the count of oil wells in the base year 1992, data which drives the pneumatic controller count in later years. The total count of oil wells in 1992 increased, which in turn decreased the difference between 1992 and 2013 well counts from the public review draft and therefore the count of pneumatic controllers from 1992 to 2013 was scaled by a lower factor.

CH_4 of 0.4 MMT CO_2 Eq., or 100 percent, and an increase in CO_2 of 4.7 MMT CO_2, or by a factor of 467.[68] Commenters on the public review draft supported this update.

Planned Improvements

Oil Well Completions and Workovers

The Inventory does not currently distinguish between oil well completions and workovers with hydraulic fracturing and oil well completions and workovers without hydraulic fracturing. In addition, current Inventory emission factors for all oil well completions and workovers were developed using an assumption that all oil well workovers and completions are flared. EPA is seeking data on completions and workovers of oil wells using hydraulic fracturing to better reflect emissions from this rapidly growing and changing sector.

On April 15, 2014, EPA released for external peer review five technical white papers on potentially significant sources of emissions in the oil and gas sector.[69] The white papers focus on technical issues covering emissions and mitigation techniques that target methane and volatile organic compounds (VOCs). The white paper "Emissions from completions and ongoing production of hydraulically fractured oil wells" discussed available data on this source. In addition, EPA's proposed revisions to the GHGRP to add reporting requirements for oil well completions and workovers with hydraulic fracturing would provide EPA with data that could inform updates to the Inventory of U.S. Greenhouse Gas Emissions and Sinks.

Commenters suggested use of data from Allen (2013) to calculate emission factors. A commenter calculated that using an estimate of 7.7 tons CH_4 per completion event and an assumption of 75 percent of new oil wells completed with hydraulic fracturing would increase the current emission estimate for this source by a factor of 400. Commenters suggested that some oil producers voluntarily report completions data to GHGRP and suggested that EPA use this data to develop emission estimates, and then reevaluate these estimates as more data become available.

Pneumatic Controllers

EPA is considering options for updating its estimates for pneumatic controllers in the Inventory. Data sources reviewed include GHGRP (EPA 2014), Allen et al. (2014) and others.[70] Commenters supported the use of direct measurement data to update this emissions source. Commenters supported the use of technology-specific emission factors and categories (e.g., high bleed, intermittent bleed, low bleed, zero bleed) to track emissions and changes in technology. Commenters suggested using GHGRP data on the split between high bleed, intermittent bleed and low bleed to develop data for this approach. A commenter suggested adding a category to address malfunction emissions, which were observed to be substantial in Allen et al. 2014. Commenters supported updating activity data from this source and suggested use of GHGRP data on number of controllers when it becomes available,

[68] For additional information, please see memo "Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2013: Proposed Revision to Refinery Emissions Estimate." EPA (2015c) available at <http://www.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>.

[69] Available online at <http://www.epa.gov/airquality/oilandgas/whitepapers.html>.

[70] For more information, please see memo "Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2013: Potential Revisions to Pneumatic Controller Estimates." (EPA 2015d) available at <http://www.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>.

extrapolated to national numbers, or use of data sources such as Allen et al. (2014) or OIPA 2014. EPA is considering these updates for the 2016 GHG Inventory.

Offshore Platforms

EPA is in the process of calculating emission factors based on the 2005 and 2008 GOADS data that will be applied to years in the time series on either side of the GOADS inventory year that provides the emission factors in future versions of the Inventory.[71] Commenters supported this update.

GHGRP

Beginning March 2015, petroleum and natural gas systems reporters to EPA's GHGRP will begin reporting additional data to EPA. The additional data will include, in some cases, information on equipment counts and other additional information that could allow for further improvements to the Inventory.

Commenters on the public review draft recommended that EPA analyze and screen GHGRP data and exclude or correct outliers. Commenters also recommended use of only measured GHGRP data in some cases.

EPA plans to review data reported to GHGRP for potential updates to data and methodology across all segments of petroleum systems.

Other Updates

EPA is evaluating several other sources for potential updates to future inventories.

Abandoned wells are not currently accounted for in the Inventory. EPA is seeking appropriate emission factors and national activity data available to calculate these emissions. Commenters supported including this source category.

EPA received comments process suggesting that bradenhead/casinghead gas emissions may be underestimated in the Inventory. In the Inventory, casinghead gas emissions are calculated using the population of stripper wells and an assumption that 80 percent of stripper wells vent casinghead gas. An emission factor of 2,345 scf CH_4/year per stripper well is applied. Comments on the Inventory noted that casinghead gas emissions are occurring in relatively new and high-production areas. EPA plans to review the method, emission factor, and assumptions used (such as that casinghead emissions occur only at stripper wells) to calculate emissions from casinghead gas in the Inventory. EPA also received comments that associated gas may be underestimated and suggesting use of GHGRP data to calculate associated gas for the Inventory. A commenter suggested that EPA use associated gas venting and flaring data from GHGRP and apply it to the population of associated gas wells in the Inventory to address the concern that casinghead gas emissions occur at a wider set of associated gas wells, not only at stripper wells.

Methane Measurement Studies

Large amounts of data and information are becoming available through EPA's GHGRP and external studies, allowing EPA to re-evaluate and make updates to inventory data. There are a variety of potential uses of data from new studies, including replacing a previous estimate or factor, verifying or QA of an existing estimate or factor, and identifying areas for updates.

In general, there are two major types of studies related to oil and gas greenhouse gas data: studies that focus on measurement or quantification of emissions from specific activities, processes and equipment (e.g., EPA's GHGRP, EDF series), and studies that focus on verification of estimates through inverse modeling (e.g., NOAA verification studies). The first type of study can lead to direct improvements to or verification of Inventory estimates. The second type of study can provide general indications on potential over- and under-estimates. EPA reviews both types of studies for data that can inform inventory updates.

[71] For more information, please see memo "Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2013: Update to Offshore Oil and Gas Platform Emission Estimates." (EPA 2015b) available at <http://www.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>.

EPA considers several factors in review of new data for use in the Inventory, including representativeness (national, regional, production-level, emissions-level), availability of data on controls, practices, and other relevant information, availability of relevant activity data, ability to develop emission factors and activity data for the time series, and whether the study includes a robust and transparent sampling approach, measurement method, and key background data.

EPA will continue to review new data from measurement studies, including upcoming data from the EDF series of CH_4 studies, to assess and potentially update Inventory estimates. EPA seeks stakeholder information on studies with data relevant to the Inventory.

Uncertainty

As described in the above section on Uncertainty, EPA calculates uncertainty for the Petroleum Systems source category based on analysis of uncertainty for the seven highest-emitting sources in the Inventory. Since conducting the 2010 uncertainty analysis there have been methodological improvements in two of the seven sources analyzed in 2010. The seven highest-emitting sources (both in the current and in previous inventories) are offshore oil platforms (shallow water), high bleed pneumatics, oil tanks, low bleed pneumatics, gas engines, offshore oil platforms (deep water) and chemical injection pumps. To update the uncertainty analysis to reflect changes that have occurred since 2010, EPA intends to collect updated information on the uncertainties associated with emission and activity factors for the current top 7 emission sources, and reanalyze the uncertainty of the petroleum industry inventory. This analysis will be conducted using the same @RISK model and IPCC methodology applied in the 2010 uncertainty analysis. EPA seeks comment on updated information on uncertainty for the top seven sources and on the approach to calculate uncertainty. For more information, see http://www.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html.

Box 3-7: 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 Inventory, emissions from naturally-produced CO_2 are estimated based on the application.

In the Inventory, 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 includes 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.

In the United States, facilities that conduct geologic sequestration of CO_2 and all other facilities that inject CO_2 underground, including facilities conducting EOR, are required to report greenhouse gas data annually to EPA through its GHGRP. Facilities conducting geologic sequestration of CO_2 are required to develop and implement an EPA-approved site-specific monitoring, reporting and verification plan, and to report the amount of CO_2 sequestered using a mass balance approach. Data from this program 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 MMT CO_2 Eq. (46,198 kt) (see Table 3-42 and Table 3-43). 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. Values for 2011 to 2013 were proxied from 2010 data.

Table 3-42: Potential Emissions from CO_2 Capture and Transport (MMT CO_2 Eq.)

Stage	1990	2005	2009	2010	2011	2012	2013
Acid Gas Removal Plants	4.8	5.8	7.0	11.6	11.6	11.6	11.6
Naturally Occurring CO_2	20.8	28.3	39.7	34.0	34.0	34.0	34.0
Ammonia Production Plants	+	0.7	0.6	0.7	0.7	0.7	0.7
Pipelines Transporting CO_2	+	+	+	+	+	+	+
Total	**25.6**	**34.7**	**47.3**	**46.2**	**46.2**	**46.2**	**46.2**

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

Table 3-43: Potential Emissions from CO_2 Capture and Transport (kt)

Stage	1990	2005	2009	2010	2011	2012	2013
Acid Gas Removal Plants	4,832	5,798	7,035	11,554	11,554	11,554	11,554
Naturally Occurring CO_2	20,811	28,267	39,725	33,967	33,967	33,967	33,967
Ammonia Production Plants	+	676	580	677	677	677	677
Pipelines Transporting CO_2	8	7	8	8	8	8	8
Total	**25,643**	**34,742**	**47,340**	**46,198**	**46,198**	**46,198**	**46,198**

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

3.7 Natural Gas Systems (IPCC Source Category 1B2b)

The U.S. natural gas system encompasses hundreds of thousands of wells, hundreds of processing facilities, and over a million miles of transmission and distribution pipelines. Overall, natural gas systems emitted 157.4 MMT CO_2 Eq. (6,295 kt) of CH_4 in 2013, a 12 percent decrease compared to 1990 emissions, and a 2 percent increase compared to 2012 emissions (see Table 3-44, Table 3-45, and Table 3-46) and 37.8 MMT CO_2 Eq. (37,808 kt) of non-combustion CO_2 in 2013, a less than 1 percent increase compared to 1990 emissions, and a 9 percent increase from 2012 emissions (see Table 3-47 and Table 3-48). The 1990 to 2013 decrease in CH_4 emissions is due primarily to the decrease in emissions from distribution and production. The 1990 to 2013 decrease in distribution emissions is due to a decrease in unprotected steel and cast iron pipelines and their replacement with plastic pipelines. The decrease in production emissions is due to increased use of plunger lifts for liquids unloading, regulatory reductions such as reductions from hydraulically fractured gas well completions and workovers resulting from the 2012 New Source Performance Standards (NSPS) for oil and gas, and from a variety of voluntary reduction activities. The 2012 to 2013 increase in CO_2 is due to increased flaring.

CH_4 and non-combustion CO_2 emissions from natural gas systems include those resulting from normal operations, routine maintenance, and system upsets. Emissions from normal operations include: natural gas engine and turbine uncombusted exhaust, bleed and discharge emissions from pneumatic controllers, 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 controllers, kimray pumps, venting for liquids unloading, condensate tanks, pipeline leaks, and offshore platforms account for the majority of CH_4 emissions in 2013. Flaring emissions account for the majority of the non-combustion CO_2 emissions. Emissions from production account for 30 percent of CH_4

emissions and 42 percent of non-combustion CO_2 emissions from natural gas systems in 2013. CH_4 emissions from field production decreased by 21 percent from 1990 to 2013; however, the trend was not stable over the time series—emissions from production generally increased through 2006 due primarily to increases in emissions from pneumatic controllers and hydraulically fractured gas well completions and workovers, and then declined from 2007 to 2013. Reasons for the 2007 to 2013 trend include an increase in plunger lift use for liquids unloading, increased voluntary reductions over that time period (including those associated with pneumatic controllers), and increased reduced emissions completions (RECs) use for well completions and workovers with hydraulic fracturing. CO_2 emissions from production increased 63 percent from 1990 to 2013 due to increases in onshore and offshore flaring.

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 14 percent of CH_4 emissions and 58 percent of non-combustion CO_2 emissions from natural gas systems. CH_4 emissions from processing increased by 6 percent from 1990 to 2013 as emissions from compressors increased as the quantity of gas produced increased. CO_2 emissions from processing decreased by 22 percent from 1990 to 2013, as a decrease in the quantity of gas processed resulted in a decrease in acid gas removal emissions.

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 U.S. transmission system. Fugitive CH_4 emissions from these compressor stations, and from pneumatic controllers account for the majority of the emissions from this stage. Uncombusted engine exhaust and pipeline venting 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 34 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. CH_4 emissions from this source decreased by 7 percent from 1990 to 2013 due to increased voluntary reductions (e.g., replacement of high bleed pneumatics with low bleed pneumatics). CO_2 emissions from transmission and storage have increased by 5 percent from 1990 to 2013 as the number of compressors has increased.

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 1,252,866 miles of distribution mains in 2013, an increase of nearly 310,000 miles since 1990 (PHMSA 2014). Distribution system emissions, which account for 21 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 pipelines and stations. An increased use of plastic piping, which has lower emissions than other pipe materials, has reduced both CH_4 and CO_2 emissions from this stage. Distribution system CH_4 emissions in 2013 were 16 percent lower than 1990 levels (changed from 39.8 MMT CO_2 Eq. to 33.3 MMT CO_2 Eq.), while distribution CO_2 emissions in 2013 were 14 percent lower than 1990 levels (CO_2 emission from this segment are less than 0.1 MMTCO_2 Eq. across the time series).

Total CH_4 emissions for the four major stages of natural gas systems are shown in MMT CO_2 Eq. (Table 3-44) and kt (Table 3-45). Table 3-46 provides additional information on how the estimates in Table 3-44 were calculated. Table 3-46 shows the calculated CH_4 release (i.e. potential emissions before any controls are applied) from each stage, and the amount of CH_4 that is estimated to have been flared, captured, or otherwise controlled, and therefore not emitted to the atmosphere. Subtracting the value for CH_4 that is controlled, from the value for calculated potential release of CH_4, results in the total emissions values. More disaggregated information on potential emissions and emissions is available in Annex 3.6. See Methodology for Estimating CH_4 and CO_2 Emissions from Natural Gas Systems.

Table 3-44: CH_4 Emissions from Natural Gas Systems (MMT CO_2 Eq.)[a]

Stage	1990	2005	2009	2010	2011	2012	2013
Field Production	59.5	75.5	62.0	56.5	51.3	49.7	47.0
Processing	21.3	16.4	19.2	17.9	21.3	22.3	22.7
Transmission and Storage	58.6	49.1	52.7	51.6	53.9	51.8	54.4
Distribution	39.8	35.4	34.1	33.5	32.9	30.7	33.3
Total	**179.1**	**176.3**	**168.0**	**159.6**	**159.3**	**154.4**	**157.4**

Note: Emissions values are presented in CO_2 equivalent mass units using IPCC AR4 GWP values.
[a] These values represent CH_4 emitted to the atmosphere. CH_4 that is captured, flared, or otherwise controlled (and not emitted to the atmosphere) has been calculated and removed from emission totals.
Note: Totals may not sum due to independent rounding.

Table 3-45: CH_4 Emissions from Natural Gas Systems (kt)[a]

Stage	1990	2005	2009	2010	2011	2012	2013
Field Production	2,380	3,018	2,482	2,262	2,052	1,989	1,879
Processing	852	655	768	717	851	891	906
Transmission and Storage	2,343	1,963	2,107	2,065	2,154	2,070	2,176
Distribution	1,591	1,417	1,365	1,338	1,315	1,226	1,333
Total	**7,165**	**7,053**	**6,722**	**6,382**	**6,371**	**6,176**	**6,295**

[a] These values represent CH_4 emitted to the atmosphere. CH_4 that is captured, flared, or otherwise controlled (and not emitted to the atmosphere) has been calculated and removed from emission totals.
Note: Totals may not sum due to independent rounding.

Table 3-46: Calculated Potential CH_4 and Captured/Combusted CH_4 from Natural Gas Systems (MMT CO_2 Eq.)

	1990	2005	2009	2010	2011	2012	2013
Calculated Potential[a]	**179.3**	**208.8**	**210.7**	**211.3**	**210.6**	**206.7**	**209.6**
Field Production	59.7	89.8	89.5	90.0	88.4	87.2	85.6
Processing	21.3	20.6	23.0	23.6	25.2	26.2	26.6
Transmission and Storage	58.6	61.7	62.5	62.8	62.7	61.5	63.1
Distribution	39.8	36.6	35.7	34.8	34.3	31.8	34.3
Captured/Combusted	**0.2**	**32.4**	**42.6**	**51.7**	**51.3**	**52.3**	**52.2**
Field Production	0.2	14.4	27.5	33.5	37.1	37.5	38.6
Processing	+	4.2	3.8	5.7	3.9	3.9	3.9
Transmission and Storage	+	12.7	9.8	11.2	8.9	9.8	8.7
Distribution	+	1.2	1.6	1.4	1.5	1.1	1.0
Net Emissions	**179.1**	**176.3**	**168.0**	**159.6**	**159.3**	**154.4**	**157.4**
Field Production	59.5	75.5	62.0	56.5	51.3	49.7	47.0
Processing	21.3	16.4	19.2	17.9	21.3	22.3	22.7
Transmission and Storage	58.6	49.1	52.7	51.6	53.9	51.8	54.4
Distribution	39.8	35.4	34.1	33.5	32.9	30.7	33.3

Note: Emissions values are presented in CO_2 equivalent mass units using IPCC AR4 GWP values.
Note: Totals may not sum due to independent rounding.
+ Emissions are less than 0.1 MMT CO_2 Eq.
[a] In this context, "potential" means the total emissions calculated before voluntary reductions and regulatory controls are applied.

Table 3-47: Non-combustion CO_2 Emissions from Natural Gas Systems (MMT CO_2 Eq.)

Stage	1990	2005	2009	2010	2011	2012	2013
Field Production	9.8	8.1	10.9	10.9	14.0	13.2	15.9
Processing	27.8	21.7	21.2	21.3	21.5	21.5	21.8

Transmission and Storage	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Distribution	+	+	+	+	+	+	+
Total	**37.6**	**30.0**	**32.2**	**32.3**	**35.6**	**34.8**	**37.8**

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

Table 3-48: Non-combustion CO_2 Emissions from Natural Gas Systems (kt)

Stage	1990	2005	2009	2010	2011	2012	2013
Field Production	9,775	8,142	10,906	10,883	13,980	13,196	15,947
Processing	27,763	21,746	21,188	21,346	21,466	21,469	21,757
Transmission and Storage	62	64	65	65	65	63	65
Distribution	46	42	41	40	40	37	40
Total	**37,645**	**29,995**	**32,201**	**32,334**	**35,551**	**34,764**	**37,808**

Note: Totals may not sum due to independent rounding.

Methodology

The methodology for natural gas emissions estimates presented in this Inventory involves the calculation of CH_4 and CO_2 emissions for over 100 emissions sources, and then the summation of emissions for each natural gas sector stage.

The calculation of emissions for each source of emissions in natural gas systems generally occurs in three steps:

Step 1. **Calculate Potential Methane –** Collect activity data on production and equipment in use and apply emission factors (i.e., scf gas per unit or activity)

Step 2. Compile Reductions Data – Calculate the amount of the methane that is not emitted, using data on voluntary action and regulations

Step 3. Calculate Net Emissions – Deduct methane that is not emitted from the total methane potential estimates to develop net CH_4 emissions, and calculate CO_2 emissions

This approach of calculating potential CH_4 and then applying reductions data to calculate net emissions was used to ensure an accurate time series that reflects real emission trends. As noted below, key data on emissions from many sources are from a 1996 report containing data collected in 1992. Since the time of this study, practices and technologies have changed. While this study still represents best available data for some emission sources, using these emission factors alone to represent actual emissions without adjusting for emissions controls would in many cases overestimate emissions. As updated emission factors reflecting changing practices are not available for most sources, the 1992 emission factors continue to be used for many sources for all years of the Inventory, but they are considered to be potential emissions factors, representing what emissions would be if practices and technologies had not changed over time.

For the Inventory, the calculated potential emissions are adjusted using data on reductions reported to Natural Gas STAR, and data on regulations that result in CH_4 reductions. As more data become available, alternate approaches may be considered. For example, new data on liquids unloading and on hydraulically fractured gas well completions and workovers enabled EPA to disaggregate or stratify these sources into distinct sub-categories based upon different technology types, each with unique emission factors and activity data.

Step 1. Calculate Potential Methane—Collect activity data on production and equipment in use and apply emission factors

In the first step, potential CH_4 is calculated by multiplying activity data (such as miles of pipeline or number of wells) by factors that relate that activity data to potential CH_4. Potential CH_4 is the amount of CH_4 that would be emitted in the absence of any control technology or mitigation activity. It is important to note that potential CH_4

factors in most cases do not represent emitted CH_4, and must be adjusted for any emissions-reducing technologies, or practices, as appropriate. For more information, please see the Annex.

Potential Methane Factors

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 EPA/GRI study was based on a combination of process engineering studies, collection of activity data and measurements at representative gas facilities conducted in the early 1990s. Methane compositions from the Gas Technology Institute (GTI, formerly GRI) Unconventional Natural Gas and Gas Composition Databases (GTI 2001) are adjusted year to year using gross production for oil and gas supply National Energy Modeling System (NEMS) 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. The majority of emission factors used in the Inventory were derived from the EPA/GRI study. The emission factors used to estimate CH_4 were also used to calculate non-combustion CO_2 emissions. Data from GTI 2001 were used to adapt the CH_4 emission factors into non-combustion related CO_2 emission factors. Additional information about CO_2 content in transmission quality natural gas was obtained from numerous U.S. transmission companies to help further develop the non-combustion CO_2 emission factors.

Although the Inventory primarily uses EPA/GRI emission factors, updates were made to the emissions estimates for several sources in recent Inventories. For liquids unloading, in the 2013 Inventory, the methodology was revised to calculate national emissions through the use region-specific emission factors developed from well data collected in a survey conducted by API/ANGA (API/ANGA 2012). In this methodology, the emission factors used for liquids unloading are not potential factors, but are factors for actual emissions. For gas well completions and workovers (refracturing) with hydraulic fracturing, in this Inventory, EPA used the 2011, 2012, and 2013 GHGRP Subpart W data to stratify the emission sources into four different categories and developed CH_4 emission factors for each category. See the Recalculations Discussion below, and EPA memos "Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2013: Revision to Hydraulically Fractured Gas Well Completions and Workovers Estimate" and "Updating GHG Inventory Estimate for Hydraulically Fractured Gas Well Completions and Workovers" for more information on the methodology for this emission source (EPA 2013d and EPA 2015c).

In addition, in 2015, an update was made to the emission factors applied to offshore platforms. Previously, the Inventory relied on the Bureau of Ocean Energy Management's (BOEM's) Gulf Offshore Activity Data System (GOADS) year 2000 inventory to develop emission factors for offshore platforms; the methodology has been updated to use more recent GOADS inventory data to develop emission factors. See the Recalculations Discussion below, and EPA memo "Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2013: Revision to Offshore Platforms Emissions Estimate" (EPA 2015b).

See Annex 3.6 for more detailed information on the methodology and data used to calculate CH_4 and non-combustion CO_2 emissions from natural gas systems.

Updates to emission factors using GHGRP data for natural gas systems and other data continue to be evaluated.

Activity Data

Activity data were taken from the following sources: DrillingInfo, Inc (DrillingInfo 2014); American Gas Association (AGA 1991–1998); Bureau of Ocean Energy Management, Regulation and Enforcement (previous Minerals and Management Service) (BOEMRE 2011a, 2011b, 2011c, 2011d); Natural Gas Liquids Reserves Report (EIA 2005); Natural Gas Monthly (EIA 2014a, 2014b, 2014c); the Natural Gas STAR Program annual emissions savings (EPA 2013c); Oil and Gas Journal (OGJ 1997–2014); Pipeline and Hazardous Materials Safety Administration (PHMSA 2014); Federal Energy Regulatory Commission (FERC 2014); Greenhouse Gas Reporting Program (EPA 2014); other Energy Information Administration data and publications (EIA 2001, 2004, 2012, 2013, 2014). 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 2014) and the Alabama State Oil and Gas Board (Alabama 2014).

For a few sources, recent direct activity data are not available. For these sources, either 2012 data was used as proxy for 2013 data, or a set of industry activity data drivers was developed and used to update activity data. 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. For example, recent data on various types of field separation equipment in the production stage (i.e., heaters, separators, and dehydrators) are unavailable. Each of these types of field separation equipment was determined to relate to the number of non-associated gas wells. Using the number of each type of field separation equipment estimated by GRI/EPA in 1992, and the number of non-associated gas wells in 1992, a factor was developed that is used to estimate the number of each type of field separation equipment throughout the time series. More information on activity data and drivers is available in Annex 3.6.

Step 2. Compile Reductions Data—Calculate the amount of the CH_4 that is not emitted, using data on voluntary action and regulations

The emissions calculated in Step 1 above represent potential emissions from an activity, and do not take into account any use of technologies and practices that reduce emissions. To take into account use of such technologies, data, where available, are collected on both regulatory and voluntary reductions. Regulatory actions reducing emissions include National Emission Standards for Hazardous Air Pollutants (NESHAP) regulations for dehydrator vents and condensate tanks. Voluntary reductions included in the Inventory are those reported to Natural Gas STAR for activities such as replacing a high bleed pneumatic device with a low bleed device, and replacing wet seals with dry seals at reciprocating compressors. For more information on these reductions, please see the Annex. The emission estimates presented in Table 3-44 and Table 3-45 are the CH_4 that is emitted to the atmosphere (i.e., net emissions), not potential emissions without capture or flaring.

The Inventory includes impacts of the New Source Performance Standards (NSPS), which came into effect in October 2012, for oil and gas (EPA 2013b). By separating gas well completions and workovers with hydraulic fracturing into four categories and developing control technology-specific CH_4 emission factors for each category, EPA is implicitly accounting for NSPS reductions from hydraulically fractured gas wells. The NSPS also has VOC reduction requirements for compressors, storage vessels, pneumatic controllers, and equipment leaks at processing plants, which will also impact CH_4 emissions in future Inventories.

Step 3. Calculate Net Emissions—Deduct CH_4 that is not emitted from the total CH_4 potential estimates to develop net CH_4 emissions, and calculate CO_2 emissions

In the final step, emission reductions from voluntary and regulatory actions are deducted from the total calculated potential emissions to estimate the net emissions that are presented in Table 3-44, and included in the Inventory totals. Note that for liquids unloading, condensate tanks, gas well completions and workovers with hydraulic fracturing, and centrifugal compressors, emissions are calculated directly using emission factors that vary by technology and account for any control measures in place that reduce CH_4 emissions. See Annex table A-17 for more information on net emissions for specific sources.

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis was conducted in 2010 to determine the level of uncertainty surrounding estimates of emissions from natural gas systems using the IPCC-recommended Approach 2 methodology (Monte Carlo Simulation technique). The @RISK software model was used to quantify the uncertainty associated with the emissions estimates using the 12 highest-emitting sources (“top 12 sources”) for the year 2009. The @RISK 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 IPCC guidance notes that in using this method, "some uncertainties that are not addressed by statistical means may exist, including those arising from omissions or double counting, or other conceptual errors, or from incomplete understanding of the processes that may lead to inaccuracies in estimates developed from models." As a result, the understanding of the uncertainty of emissions estimates for this category evolves and improves as the underlying methodologies and datasets improve.

The uncertainty analysis conducted in 2010 has not yet been updated for the 1990 through 2013 Inventory years; instead, the uncertainty percentage ranges calculated previously were applied to 2013 emissions estimates. The majority of sources in the current Inventory were calculated using the same emission factors and activity data for which PDFs were developed in the 1990 through 2009 uncertainty analysis. As explained in the Methodology section above and the recalculations discussion below, several emission sources have undergone recent methodology

revisions, and the 2009 uncertainty ranges will not reflect the uncertainty associated with the recently revised emission factors and activity data sources. Please see discussion on Planned Improvements.

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 2013, based on the previously-conducted uncertainty assessment using the recommended IPCC methodology. The heterogeneous nature of the natural gas industry makes it difficult to sample facilities that are completely representative of the entire industry. Additionally, highly variable emission rates were measured among many system components, making the calculated average emission rates uncertain. The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-49. Natural gas systems CH_4 emissions in 2013 were estimated to be between 127.5 and 187.3 MMT CO_2 Eq. at a 95 percent confidence level. Natural gas systems non-energy CO_2 emissions in 2013 were estimated to be between 30.6 and 49.1 MMT CO_2 Eq. at 95 percent confidence level.

Table 3-49: Approach 2 Quantitative Uncertainty Estimates for CH_4 and Non-energy CO_2 Emissions from Natural Gas Systems (MMT CO_2 Eq. and Percent)

Source	Gas	2013 Emission Estimate (MMT CO_2 Eq.)[b]	Uncertainty Range Relative to Emission Estimate[a] (MMT CO_2 Eq.)		(%)	
			Lower Bound[b]	Upper Bound[b]	Lower Bound[b]	Upper Bound[b]
Natural Gas Systems	CH_4	157.4	127.5	187.3	-19%	+30%
Natural Gas Systems[c]	CO_2	37.8	30.6	49.1	-19%	+30%

[a] Range of emission estimates predicted by Monte Carlo Simulation 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 3-45 and Table 3-47.
[c] 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.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2013. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification Discussion

The natural gas emission estimates in the Inventory are continually being reviewed and assessed to determine whether emission factors and activity factors accurately reflect current industry practices. A QA/QC analysis was performed for data gathering and input, documentation, and calculation. QA/QC checks are consistently conducted to minimize human error in the model calculations. EPA performs a thorough review of information associated with new studies, GHGRP data, regulations, public webcasts, and the Natural Gas STAR Program to assess whether the assumptions in the Inventory are consistent with current industry practices. In addition, EPA receives feedback through annual expert and public review periods. Feedback received is noted in the Recalculations and Planned Improvement sections.

Several recent studies have measured emissions at the source level and at the national or regional level (e.g., EDF series of studies) with results that often differ from EPA's estimate of emissions. Commenters to the Inventory noted discrepancies between bottom-up inventory estimates and emissions estimated with satellite and aircraft data. Please see note on Methane Measurement Studies in the Planned Improvements section.

Recalculations Discussion

For the current Inventory, emission estimates have been revised to reflect the GWPs provided in the *IPCC Fourth Assessment Report* (AR4) (IPCC 2007). AR4 GWP values differ slightly from those presented in the *IPCC Second Assessment Report* (SAR) (IPCC 1996) (used in the previous inventories) which results in time-series recalculations for most inventory sources. Under the most recent reporting guidelines (UNFCCC 2014), countries are required to report using the AR4 GWPs, which reflect an updated understanding of the atmospheric properties of each

greenhouse gas. The GWPs of CH_4 and most fluorinated greenhouse gases have increased, leading to an overall increase in calculated CO_2-equivalent emissions from CH_4, HFCs, and PFCs. The GWPs of N_2O and SF_6 have decreased, leading to a decrease in calculated CO_2-equivalent emissions from N_2O. The AR4 GWPs have been applied across the entire time series for consistency. For more information please see the Recalculations and Improvements Chapter.

EPA received information and data related to the emission estimates through the Inventory preparation process, previous Inventories' formal public notice periods, GHGRP data, and new studies. EPA carefully evaluated relevant information available, and made several updates, including revisions to offshore platforms, pneumatic controllers, well counts data, and hydraulically fractured gas well completions and workovers.

In addition, revisions to activity data resulted in changes to emission estimates for several sources. For example, the previous (2014) Inventory used 2011 data as a proxy for condensate production for 2012. The current (2015) Inventory was updated to use the most recent data on condensate production. Large increases in production in the Rocky Mountain and Gulf Coast regions resulted in an increase in calculated 2012 CH_4 emissions from condensate tanks of 0.6 MMT CO_2 Eq., or 15 percent.

The combined impact of all revisions on 2012 natural gas production segment emissions described below, compared to the 2014 Inventory, is a decrease in CH_4 emissions of approximately 0.2 MMT CO_2 Eq., and a decrease in CO_2 emissions of 0.5 MMT, or around 1 percent.[72] Recalculations in the offshore gas platforms estimates resulted in a large decrease in the 2012 CH_4 emission estimate from this source in the production segment, from 7.2 MMT CO_2 Eq. in the previous (2014) Inventory, to 3.8 MMT CO_2 Eq. in the current (2015) Inventory. Recalculations to the onshore gas production emissions estimates resulted in an increase in the 2012 CH_4 emission estimate for onshore sources, from 42.6 MMT CO_2 Eq. in the previous (2014) Inventory, to 46.0 MMT CO_2 Eq. in the current (2015) Inventory. Methane emission estimates for other segments (i.e., processing, transmission and storage, and distribution) changed by less than 0.5 percent.

Across the 1990-2012 time series, compared to the previous (2014) Inventory, in the current (2015) Inventory, the total CH_4 emissions estimate decreased by 5.2 MMT CO_2 Eq. on average (or 3 percent), with the largest decreases in the estimate occurring in early years of the time series; and the CO_2 emissions estimate decreased <0.1 MMT CO_2 on average (<1 percent).

Offshore Platforms

The U.S. Department of the Interior (DOI) began Inventorying offshore platform greenhouse gas emissions in the Bureau of Ocean Energy Management's (BOEM) Gulf Offshore Activity Data System (GOADS) in 2000 with subsequent revisions in 2005, 2008, and 2011. The original year 2000 GOADS data were used to develop the emission factors used in the previous Inventory calculations. There have been significant improvements in GOADS data collection and processing since 2000. For the final version of the 1990-2013 Inventory, the 2011 GOADS data were used to revise the emission factors used to calculate offshore oil and gas emissions in the Inventory. The platforms in GOADS were separated into the four categories used in the GHG Inventory methodology: oil versus gas platforms and deep water versus shallow water platforms. Then, the reported emissions for each platform group were used to develop average platform emission factors for Natural Gas Systems and Petroleum Systems. EPA is in the process of calculating emission factors based on the 2005 and 2008 GOADS data that will be applied to years in the time series on either side of the GOADS inventory year that provides the emission factors in future versions of the Inventory. Updated activity data were also sought for oil and gas offshore platforms, as the current Inventory activity data is based on DOI 2010 data. At this time no new references were identified that provide current year (2013) and historic platform counts, on a consistent basis. The impact of this improvement is a decrease in emissions across the time series. For the year 2012, the CH_4 emissions decrease due to use of revised emission factors is approximately 3.5 MMT CO_2 Eq.[73] Commenters on the public review draft supported this update, and recommended that EPA improve its activity data for the number of platforms by using Lexco/OWL, and that EPA

[72] Additional information on recent changes to the Inventory can be found at <http://www.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>

[73] For additional information, please see memo "Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2013: Revision to Offshore Platform Emissions." EPA (2015b) available at <http://www.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>

improve data on flaring of offshore gas, for example, by reviewing platform data to determine which platforms have a flare.

Gas Well Completions with Hydraulic Fracturing and Workovers with Hydraulic Fracturing (Refracturing)

In the previous Inventory, completions and workovers from the 2011 and 2012 GHGRP data sets were stratified into four different categories: hydraulic fracturing completions and workovers that vent, flared hydraulic fracturing completions and workovers, hydraulic fracturing completions and workovers with RECs, and hydraulic fracturing completions and workovers with RECs that flare. For each category, 2011 and 2012 GHGRP Subpart W data were used to develop control technology-specific methane emission factors and estimate corresponding activity data for the entire time series.

In the current Inventory, the latest GHGRP data available for 2011, 2012, and 2013 were used to develop updated emission factors for the four categories. The emission factors were applied throughout the time series.

Using the same method as was used in the previous Inventory, a time series of activity data was developed for each category for 1990 through 2013. For RECs, 0 percent was assumed for RECs use from 1990 to 2000; GHGRP RECs percentage was used for 2011, 2012, and 2013; and then linear interpolation was used between the 2000 and 2011 percentages for RECs use. For flaring, 10 percent (the average of the percentage of completions and workovers that were flared in 2011 and 2012 GHGRP data) flaring was assumed from 1990 to 2010 to recognize that some flaring occurred over that time period. For 2011, 2012, and 2013, the GHGRP data on flaring was used. The remaining completions and workovers are assigned to the venting category.

This methodology allows the Inventory to reflect changes in RECs counts and flaring, including those resulting from NSPS Subpart OOOO.

Changes made to the emission factors for gas well completions and workovers with hydraulic fracturing resulted in a decrease in the estimate of CH_4 emissions for all years in the time series. This overall decrease due to the change in the data source is accompanied by declining emissions over time, reflecting impacts of the 2012 NSPS for oil and gas (in effect as of October 2012) which requires control of gas from hydraulically fractured gas well completions and workovers.

This update resulted in a decrease in the emission estimate for 2012 of approximately 2 MMT CO_2 Eq.[74]

Commenters on the Inventory generally supported this update. However, commenters also suggested use of only measured data from GHGRP, removal of outliers from GHGRP, and the consolidation of the emission factors into two categories (controlled versus uncontrolled) instead of four. A commenter suggested removing 2011 data from the GHGRP data used to develop the emission factors for hydraulically fractured gas well completions and workovers. Commenters suggested further subcategorization between completions and workovers.

EPA will consider these comments as it reviews data for this and other GHGRP categories for potential updates in next year's GHG Inventory.

Natural Gas STAR Reductions

In general, the Inventory continues to use aggregated Natural Gas STAR reductions by natural gas system segment (i.e., production, processing, transmission and storage, and distribution). For some sources, specific emissions reductions activities reported to Natural Gas STAR are matched to potential emissions calculated in the Inventory to calculate net emissions for those sources.

[74] For additional information on the revisions, please see memo "Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2013: Proposed Revision to Hydraulically Fractured Gas Well Completions and Workovers Estimate." (EPA 2015c) available at <http://www.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>

Natural Gas STAR Reductions—Pneumatic Controllers

In previous Inventories, all production segment reductions related to pneumatic controllers that are reported to Natural Gas STAR were assigned to the natural gas systems category. In the final version of the current Inventory, the production segment reductions related to pneumatic controllers have been allocated to the natural gas and petroleum systems categories based upon the calculated potential emissions for pneumatic controllers in each source category. EPA calculated the fraction of potential emissions from pneumatic controllers from natural gas systems out of the total potential pneumatic controller emissions from both natural gas and petroleum systems. On average across all Inventory years, potential pneumatic controller emissions from natural gas systems make up 65 percent of total potential pneumatic controller emissions from both source categories. EPA then applied the year-specific potential emissions fraction to the reported Natural Gas STAR pneumatic controller reductions and allocated that portion of the reductions to the natural gas systems source category. This update resulted in an increase in natural gas CH_4 emissions (increase of approximately 8 MMT CO_2 Eq. from the previous Inventory estimate for 2012) and a decrease in petroleum systems CH_4 emissions.

Table 3-50: Pneumatic Controllers Activity Data and Emissions

Data Element	1990	2000	2005	2010	2012	2013
# of Pneumatic Controllers	233,792	300,408	384,433	466,536	468,466	459,304
Calculated Potential Methane (kt)	539	759	967	1,178	1,185	1,159
Natural Gas STAR Reductions (kt)	3	76	160	530	628	620
Net Emissions (kt)	**537**	**683**	**807**	**647**	**557**	**539**

Well Counts and Completion and Workover Counts

For the public review draft, the time series has been updated with revised well counts and completion and workover counts based on DrillingInfo (HPDI) data. Due to revisions to EPA's processing of DrillingInfo (HPDI) data, well counts across the time series have changed from previous years. For additional information, please see memo "Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2013: Revision to Data Source for Well Counts." (EPA 2015a). Commenters to the public review draft suggested that EPA may be overestimating the number of associated gas wells, and that EPA's approach may be inconsistent with EIA and state approaches. See Planned Improvements section on associated gas wells.

For completions and workovers, the Inventory uses GHGRP Subpart W event counts for available years (2011 to 2013) as the activity data basis. Due to the reporting threshold in EPA's GHGRP, using data from EPA's GHGRP alone will not provide a complete national estimate of activity data and emissions. However, the completion and workover counts in GHGRP exceed those calculated using the DrillingInfo data and therefore provide a more complete data set than the DrillingInfo approach. If EPA identifies an opportunity to use DrillingInfo (HPDI) data for improved completion and workover counts for recent years, then activity data and therefore emissions from completions and workovers are expected to increase in years 2011 forward.[75]

Planned Improvements

EPA will continue to refine the emission estimates to reflect the most robust information available. Substantial amounts of new information will be made available in the coming years through a number of channels, including EPA's GHGRP, research studies by various organizations, government and academic researchers, and industry. Relevant ongoing studies are collecting new information related to natural gas system emissions (e.g. Environmental Defense Fund (EDF) study series data on natural gas systems, including new measurements on gathering and boosting, processing, transmission and storage, and distribution). EPA looks forward to reviewing information and data from these studies as they become available for potential incorporation in the Inventory.

[75] For additional information, please see memo "Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2013: Update to Data Source for Well Counts." EPA (2015a) available at <http://www.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>

Gas Well Liquids Unloading

EPA is considering updates to its estimates for liquids unloading. Data from a 2012 report published by the American Petroleum Institute (API) and America's Natural Gas Alliance (ANGA) were used beginning with the 1990-2011 Inventory (published 2013) to develop regional activity data and regional emission factors for gas well liquids unloading activities for Natural Gas Systems. EPA is considering how data from GHGRP and Allen et al. (2014a) can be used to update the Inventory estimates for this source.[76] Commenters supported the use of direct measurement data to update this emission source.

Offshore Platforms

EPA is in the process of calculating emission factors based on the 2005 and 2008 GOADS data that will be applied to years in the time series on either side of the GOADS inventory year that provides the emission factors for future versions of the Inventory.[77]

Pneumatic Controllers

EPA is considering options for updating its estimates for pneumatic controllers in the Inventory. Data sources reviewed include EPA's GHGRP (2014), Allen et al. (2014) and others.[78] Commenters supported the use of direct measurement data to update this emissions source. Commenters supported the use of technology-specific emission factors and categories (e.g. high bleed, intermittent bleed, low bleed, zero bleed) to track emissions and changes in technology. Commenters suggested using GHGRP data on the split between high bleed, intermittent bleed and low bleed to develop data for this approach. A commenter suggested adding a category to address malfunction emissions, which were observed to be substantial in Allen et al. 2014b. Commenters supported updating activity data from this source and suggested use of GHGRP data on number of controllers when it becomes available, extrapolated to national numbers, or use of data sources such as Allen et al. (2014b) or OIPA 2014. EPA is considering these updates for the 2016 Inventory.

GHGRP

Beginning March 2015, petroleum and natural gas systems reporters to EPA's GHGRP will begin reporting additional data to EPA. The additional data will include, in some cases, information on equipment counts and other additional information that could allow for further improvements to the Inventory.

Commenters on the public review draft recommended that EPA analyze and screen GHGRP data and exclude or correct outliers. Commenters also recommended use of only measured GHGRP data in some cases.

EPA plans to review data reported to its GHGRP for potential updates to data and methodology across all segments of natural gas systems.

Transmission and Storage

Commenters noted opportunities to update estimates for transmission and storage using data from EPA's GHGRP, noting the use of direct measurements for many sources in transmission and storage. Commenters noted additional

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[76] Please see the memo "Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2013: Potential Revisions to Liquids Unloading Estimates" (EPA 2015e) available at <http://www.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>

[77] Please see the memo "Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2013: Update to Offshore Oil and Gas Platforms Emissions Estimate" (EPA 2015b) available at <http://www.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>

[78] For more information, please see the memo "Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2013: Potential Revisions to Pneumatic Controller Emission Estimate" (EPA 2015d) available at <http://www.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>

sources of data that could potentially be used for Inventory updates include the EDF series (e.g., Colorado State University paper), and a Pipeline Research Council International project.

Commenters suggested reconsidering the approaches used to calculate activity data in transmission and storage. For example, the estimate for national storage facilities is based on residential gas consumption.

EPA will review data from its GHGRP and other sources for potential updates to the data and methods used to calculate emissions from transmission and storage.

Distribution

Commenters recommended revisions to distribution segment emissions estimates. EPA looks forward to reviewing new data on distribution systems (such as data from the EDF series of studies) as they become available.

Commenters suggested updating the approach to estimating M&R station activity data, which is currently based on annual throughput value, which can cause volatility in the annual activity data. EPA plans to review available data for potential updates to this source.

Associated Gas Wells

Commenters to the public review draft of the Inventory suggested that EPA's approach to estimating the number of associated gas wells may overestimate this population. EPA's approach was to include any well with a gas-to-oil ratio (GOR) greater than 0 Mcf/bbl in the associated gas well category. Commenters noted that it is very common for wells that produce mainly oil to also produce a small amount of gas. EPA will investigate alternative thresholds such as a GOR greater than 6 Mcf/bbl for the 2016 Inventory. In addition, EPA will consider whether the emissions source calculations that include associated gas wells should be expanded.

Other Updates

EPA is evaluating several other sources for potential updates to future Inventories.

Abandoned wells are not currently accounted for in the Inventory. EPA is seeking appropriate emission factors and national activity data available to calculate these emissions. Commenters supported including this source category.

Commenters recommended that EPA separate out emissions from gathering and boosting facilities from those from field production sites and noted that upcoming studies and GHGRP data may inform emissions estimates from this source.

Commenters recommended updating production segment fugitive emissions estimates.

Commenters recommended development of emission factors and activity data on a regional as opposed to a national basis.

Methane Measurement Studies

Large amounts of data and information are becoming available through EPA's GHGRP and external studies, allowing EPA to re-evaluate and make updates to Inventory data. There are a variety of potential uses of data from new studies, including replacing a previous estimate or factor, verifying or QA of an existing estimate or factor, and identifying areas for updates.

In general, there are two major types of studies related to oil and gas greenhouse gas data: studies that focus on measurement or quantification of emissions from specific activities, processes and equipment (e.g., EPA's GHGRP, EDF series), and studies that focus on verification of estimates through inverse modeling (e.g., NOAA verification studies). The first type of study can lead to direct improvements to or verification of Inventory estimates. The second type of study can provide general indications on potential over- and under-estimates. EPA reviews both types of studies for data that can inform inventory updates.

EPA considers several factors in review of new data for use in the Inventory, including representativeness (national, regional, production-level, emissions-level), availability of data on controls, practices, and other relevant information, availability of relevant activity data, ability to develop emission factors and activity data for the time series, and whether the study includes a robust and transparent sampling approach, measurement method, and key background data

EPA will continue to review new data from measurement studies, including upcoming data from the EDF series of methane studies, to assess and potentially update Inventory estimates. EPA seeks stakeholder information on studies with data relevant to the Inventory.

Uncertainty

As described in the above section on Uncertainty, EPA calculates uncertainty for the Natural Gas Systems source category based on analysis of uncertainty for the twelve highest-emitting sources in the Inventory. Since conducting the 2010 uncertainty analysis there have been methodology improvements in seven of the twelve top sources analyzed in 2010, which have resulted in a shift in which sources make up the top twelve sources list. Sources included in the top twelve methane emissions sources for 2009 were reciprocating compressor fugitives (processing), reciprocating compressor fugitives (transmission), Northeast liquids unloading, Midcentral pneumatic device vents, centrifugal compressors (wet seals, transmission), Midcentral liquids unloading, Rocky Mountain pneumatic device vents, Rocky Mountain gas well workovers with hydraulic fracturing, Rocky Mountain liquids unloading, South West gas well completions with hydraulic fracturing, Gulf Coast liquids unloading, and shallow water gas platforms. Sources in the top twelve methane emissions sources in the current Inventory for year 2013 emissions (without separating sources by region and taking into account Gas STAR reductions, which were not accounted for in the previous assessment) are reciprocating compressor fugitives (transmission), pneumatic device vents (production), reciprocating compressor fugitives (processing), kimray pumps (production), liquids unloading (production), centrifugal compressors (wet seals, processing), condensate tanks (production), pneumatic controllers (transmission), gas engines (processing), reciprocating compressors (storage), fugitives from cast iron steel (distribution), gas engines (production).

In response to the change in the composition of the top twelve sources, EPA intends to collect updated information on the uncertainties associated with emission and activity factors for the current top emission sources, and reanalyze the uncertainty of the natural gas systems inventory. This analysis will be conducted using the same @RISK model and IPCC methodology applied in the 2010 uncertainty analysis. EPA seeks comment on updated information on uncertainty for the top 12 sources and on the approach to calculate uncertainty. For more information, see http://www.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html.

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 2013 are reported in Table 3-51.

Table 3-51: NO_x, CO, and NMVOC Emissions from Energy-Related Activities (kt)

Gas/Source	1990	2005	2009	2010	2011	2012	2013
NO_x	**21,106**	**16,602**	**12,798**	**12,004**	**11,796**	**11,051**	**10,557**
Mobile Combustion	10,862	10,295	7,797	7,290	7,294	6,788	6,283
Stationary Combustion	10,023	5,858	4,452	4,092	3,807	3,567	3,579
Oil and Gas Activities	139	321	468	545	622	622	622
Waste Combustion	82	128	81	77	73	73	73
International Bunker Fuels[a]	*1,956*	*1,704*	*1,692*	*1,790*	*1,553*	*1,398*	*1,139*
CO	**125,640**	**64,985**	**44,819**	**45,148**	**44,088**	**42,273**	**40,459**
Mobile Combustion	119,360	58,615	39,256	39,475	38,305	36,491	34,676
Stationary Combustion	5,000	4,648	4,036	4,103	4,170	4,170	4,170
Waste Combustion	978	1,403	1,164	1,084	1,003	1,003	1,003
Oil and Gas Activities	302	318	363	487	610	610	610
International Bunker Fuels[a]	*103*	*133*	*121*	*136*	*137*	*133*	*129*
NMVOCs	**12,620**	**7,191**	**7,200**	**7,464**	**7,759**	**7,449**	**7,139**

Mobile Combustion	10,932	5,724	4,650	4,591	4,562	4,252	3,942
Oil and Gas Activities	554	510	1,894	2,205	2,517	2,517	2,517
Stationary Combustion	912	716	553	576	599	599	599
Waste Combustion	222	241	103	92	81	81	81
International Bunker Fuels[a]	*57*	*54*	*53*	*56*	*51*	*46*	*41*

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

Methodology

Emission estimates for 1990 through 2013 were obtained from data published on the National Emission Inventory (NEI) Air Pollutant Emission Trends web site (EPA 2015), and disaggregated based on EPA (2003). Emission estimates for 2012 and 2013 for non-EGU and non-mobile sources are held constant from 2011 in EPA (2015). 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 applications from various agencies.

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 2013. 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.[79] 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).[80]

[79] 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).

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

Two transport modes are addressed under the IPCC definition of international bunker fuels: aviation and marine.[81] Greenhouse gases emitted from the combustion of international bunker fuels, like other fossil fuels, include CO_2, CH_4 and N_2O for marine transport modes, and CO_2 and N_2O for aviation transport modes. 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.[82]

Emissions of CO_2 from aircraft are essentially a function of fuel use. N_2O emissions also depend upon engine characteristics, flight conditions, and flight phase (i.e., take-off, climb, cruise, decent, and landing). Recent data suggest that little or no CH_4 is emitted by modern engines (Anderson et al. 2011), and as a result, CH_4 emissions from this category are considered zero. 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 2013 from the combustion of international bunker fuels from both aviation and marine activities were 100.7 MMT CO_2 Eq., or 3.6 percent below emissions in 1990 (see Table 3-52 and Table 3-53). Emissions from international flights and international shipping voyages departing from the United States have increased by 72.6 percent and decreased by 47.9 percent, respectively, since 1990. The majority of these emissions were in the form of CO_2; however, small amounts of CH_4 (from marine transport modes) and N_2O were also emitted.

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

Gas/Mode	1990	2005	2009	2010	2011	2012	2013
CO_2	**103.5**	**113.1**	**106.4**	**117.0**	**111.7**	**105.8**	**99.8**
Aviation	38.0	60.1	52.8	61.0	64.8	64.5	65.7
Commercial	*30.0*	*55.6*	*49.2*	*57.4*	*61.7*	*61.4*	*62.8*
Military	*8.1*	*4.5*	*3.6*	*3.6*	*3.1*	*3.1*	*2.9*
Marine	65.4	53.0	53.6	56.0	46.9	41.3	34.1
CH_4	**0.2**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Aviation [a]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Marine	0.2	0.1	0.1	0.1	0.1	0.1	0.1
N_2O	**0.9**	**1.0**	**0.9**	**1.0**	**1.0**	**0.9**	**0.9**
Aviation	0.4	0.6	0.5	0.6	0.6	0.6	0.6
Marine	0.5	0.4	0.4	0.4	0.4	0.3	0.2
Total	**104.5**	**114.2**	**107.5**	**118.1**	**112.8**	**106.8**	**100.7**

Note: Emissions values are presented in CO_2 equivalent mass units using IPCC AR4 GWP values.
Note: Totals may not sum due to independent rounding. Includes aircraft cruise altitude emissions.
[a] CH_4 emissions from aviation are estimated to be zero.

[81] 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).

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

Table 3-53: CO_2, CH_4 and N_2O Emissions from International Bunker Fuels (kt)

Gas/Mode	1990	2005	2009	2010	2011	2012	2013
CO_2	**103,463**	**113,139**	**106,410**	**116,992**	**111,660**	**105,805**	**99,763**
Aviation	38,034	60,125	52,785	60,967	64,790	64,524	65,664
Marine	65,429	53,014	53,625	56,025	46,870	41,281	34,099
CH_4	**7**	**5**	**5**	**6**	**5**	**4**	**3**
Aviation [a]	0	0	0	0	0	0	0
Marine	7	5	5	6	5	4	3
N_2O	**3**	**3**	**3**	**3**	**3**	**3**	**3**
Aviation	1	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.
[a] CH_4 emissions from aviation are estimated to be zero.

Table 3-54: Aviation CO_2 and N_2O Emissions for International Transport (MMT CO_2 Eq.)

Aviation Mode	1990	2005	2009	2010	2011	2012	2013
Commercial Aircraft	30.0	55.6	49.2	57.4	61.7	61.4	62.8
Military Aircraft	8.1	4.5	3.6	3.6	3.1	3.1	2.9
Total	**38.0**	**60.1**	**52.8**	**61.0**	**64.8**	**64.5**	**65.7**

Note: Emissions values are presented in CO_2 equivalent mass units using IPCC AR4 GWP values.
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. Carbon 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 3.8 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 (2015) and USAF (1998), and heat content for jet fuel was taken from EIA (2015). A complete description of the methodology and a listing of the various factors employed can be found in Annex 2.1. See Annex 3.8 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 *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: 0.1 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 domestic and international aircraft fuel consumption were developed by the U.S. Federal Aviation Administration (FAA) using radar-informed data from the FAA Enhanced Traffic Management System (ETMS) for 1990, 2000 through 2013 as modeled with the Aviation Environmental Design Tool (AEDT). This bottom-up approach is built from modeling dynamic aircraft performance for each flight occurring within an individual calendar year. The analysis incorporates data on the aircraft type, date, flight identifier, departure time, arrival time, departure airport, arrival airport, ground delay at each airport, and real-world flight trajectories. To generate results for a given flight within AEDT, the radar-informed aircraft data is correlated with engine and aircraft performance data to calculate fuel burn and exhaust emissions. Information on exhaust emissions for in-production aircraft engines comes from the International Civil Aviation Organization (ICAO) Aircraft Engine Emissions Databank

(EDB). This bottom-up approach is in accordance with the Tier 3B method from the *2006 IPCC Guidelines* (IPCC 2006).

International aviation CO_2 estimates for 1990 and 2000 through 2013 are obtained from FAA's AEDT model (FAA 2015). The radar-informed method that was used to estimate CO_2 emissions for commercial aircraft for 1990, and 2000 through 2013 is not possible for 1991 through 1999 because the radar data set is not available for years prior to 2000. FAA developed OAG schedule-informed inventories modeled with AEDT and great circle trajectories for 1990, 2000 and 2010. Because fuel consumption and CO_2 emission estimates for years 1991 through 1999 are unavailable, consumption estimates for these years were calculated using fuel consumption estimates from the Bureau of Transportation Statistics (DOT 1991 through 2013), adjusted based on 2000 through 2005 data.

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 from DoD's Defense Logistics Agency Energy (DLA Energy 2014). 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 3-55. See Annex 3.8 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 2011, 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 DLA Energy (2014). The total amount of fuel provided to naval vessels was reduced by 21 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 3-56.

Table 3-55: Aviation Jet Fuel Consumption for International Transport (Million Gallons)

Nationality	1990	2005	2009	2010	2011	2012	2013
U.S. and Foreign Carriers	3,222	5,983	5,293	6,173	6,634	6,604	6,748
U.S. Military	862	462	367	367	319	321	294
Total	**4,084**	**6,445**	**5,660**	**6,540**	**6,953**	**6,925**	**7,042**

Note: Totals may not sum due to independent rounding.

Table 3-56: Marine Fuel Consumption for International Transport (Million Gallons)

Fuel Type	1990	2005	2009	2010	2011	2012	2013
Residual Fuel Oil	4,781	3,881	4,040	4,141	3,463	3,069	2,537
Distillate Diesel Fuel & Other	617	444	426	476	393	280	235
U.S. Military Naval Fuels	522	471	374	448	382	381	308
Total	**5,920**	**4,796**	**4,841**	**5,065**	**4,237**	**3,730**	**3,081**

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.[83] 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 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* (IPCC 2006) 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.[84]

There is also concern regarding the reliability of the existing DOC (2013) 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 2013. Details on the emission trends through time are described in more detail in the Methodology section, above.

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

[84] 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.

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

For the current Inventory, emission estimates have been revised to reflect the GWPs provided in the *IPCC Fourth Assessment Report* (AR4) (IPCC 2007). AR4 GWP values differ slightly from those presented in the *IPCC Second Assessment Report* (SAR) (IPCC 1996) (used in the previous Inventories) which results in time-series recalculations for most inventory sources. Under the most recent reporting guidelines (UNFCCC 2014), countries are required to report using the AR4 GWPs, which reflect an updated understanding of the atmospheric properties of each greenhouse gas. The GWPs of CH_4 and most fluorinated greenhouse gases have increased, leading to an overall increase in CO_2-equivalent emissions from CH_4, HFCs, and PFCs. The GWPs of N_2O and SF_6 have decreased, leading to a decrease in CO_2-equivalent emissions for these greenhouse gases. The AR4 GWPs have been applied across the entire time series for consistency. For more information please see the Recalculations and Improvements Chapter.

In addition, changes to emission estimates are due to revisions made to historical activity data for military aircraft consumption from DLA Energy 2014. These historical data changes resulted in changes to the emission estimates for the most recent inventory year compared to the previous Inventory. This equaled a decrease in emissions from international bunker fuels of less than 0.1 MMT CO_2 Eq. (less than 0.01 percent) in total emissions in 2012.

Planned Improvements

The feasibility of including data from a broader range of domestic and international sources for bunker fuels, including data from studies such as the Third IMO GHG Study 2014, is being considered.

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 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 complete description of this methodological approach, see the *Land Use, Land Use Change and Forestry* chapter (Chapter 6), 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 2013, total CO_2 emissions from the burning of woody biomass in the industrial, residential, commercial, and electricity generation sectors were approximately 208.6 MMT CO_2 Eq. (208,594 kt) (see Table 3-57 and Table 3-58). As the largest consumer of woody biomass, the industrial sector was responsible for 57.6 percent of the CO_2 emissions from this source. The residential sector was the second largest emitter, constituting 28.7 percent of the total, while the commercial and electricity generation sectors accounted for the remainder.

Table 3-57: CO_2 Emissions from Wood Consumption by End-Use Sector (MMT CO_2 Eq.)

End-Use Sector	1990	2005	2009	2010	2011	2012	2013
Industrial	135.3	136.3	110.6	119.5	122.9	125.7	120.2
Residential	59.8	44.3	51.6	45.4	46.4	43.3	59.8
Commercial	6.8	7.2	7.5	7.4	7.1	6.3	7.2
Electricity Generation	13.3	19.1	18.6	20.2	18.8	19.6	21.3
Total	**215.2**	**206.9**	**188.2**	**192.5**	**195.2**	**194.9**	**208.6**

Note: Totals may not sum due to independent rounding.

Table 3-58: CO_2 Emissions from Wood Consumption by End-Use Sector (kt)

End-Use Sector	1990	2005	2009	2010	2011	2012	2013
Industrial	135,348	136,269	110,610	119,537	122,865	125,724	120,202
Residential	59,808	44,340	51,558	45,371	46,402	43,309	59,808
Commercial	6,779	7,218	7,486	7,385	7,131	6,257	7,241
Electricity Generation	13,252	19,074	18,566	20,169	18,784	19,612	21,344
Total	**215,186**	**206,901**	**188,220**	**192,462**	**195,182**	**194,903**	**208,594**

Note: Totals may not sum due to independent rounding.

The transportation sector is responsible for most of the ethanol consumption in the United States. Ethanol is currently produced primarily from corn grown in the Midwest, but it can be produced from a variety of biomass feedstocks. Most ethanol for transportation use is blended with gasoline to create a 90 percent gasoline, 10 percent by volume ethanol blend known as E-10 or gasohol.

In 2013, the United States consumed an estimated 1,091.8 trillion Btu of ethanol, and as a result, produced approximately 74.7 MMT CO_2 Eq. (74,743 kt) (see Table 3-59 and Table 3-60) of CO_2 emissions. Ethanol production and consumption has grown significantly since 1990 due to the favorable economics of blending ethanol into gasoline and federal policies that have encouraged use of renewable fuels.

Table 3-59: CO_2 Emissions from Ethanol Consumption (MMT CO_2 Eq.)

End-Use Sector	1990	2005	2009	2010	2011	2012	2013
Transportation	4.1	22.4	61.2	71.3	71.5	71.5	73.4
Industrial	0.1	0.5	0.9	1.1	1.1	1.1	1.2
Commercial	+	0.1	0.2	0.2	0.2	0.2	0.2
Total	**4.2**	**22.9**	**62.3**	**72.6**	**72.9**	**72.8**	**74.7**

+ Does not exceed 0.05 MMT CO_2 Eq.

Note: Totals may not sum due to independent rounding.

Table 3-60: CO_2 Emissions from Ethanol Consumption (kt)

End-Use Sector	1990	2005	2009	2010	2011	2012	2013
Transportation[a]	4,136	22,414	61,193	71,287	71,537	71,510	73,354
Industrial	56	468	885	1,134	1,146	1,142	1,206
Commercial	34	60	193	226	198	175	183
Total	**4,227**	**22,943**	**62,272**	**72,647**	**72,881**	**72,827**	**74,743**

[a] See Annex 3.2, Table A-92 for additional information on transportation consumption of these fuels.

Note: Totals may not sum due to independent rounding.

Methodology

Woody biomass emissions were estimated by applying two EIA gross heat contents (Lindstrom 2006) to U.S. consumption data (EIA 2014) (see Table 3-61), provided in energy units for the industrial, residential, commercial, and electric generation sectors. 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 MMT C/QBtu (EPA 2010) to U.S. ethanol consumption estimates that were provided in energy units (EIA 2015) (see Table 3-62).

Table 3-61: Woody Biomass Consumption by Sector (Trillion Btu)

End-Use Sector	1990	2005	2009	2010	2011	2012	2013
Industrial	1,441.9	1,451.7	1,178.4	1,273.5	1,308.9	1,339.4	1,280.6
Residential	580.0	430.0	500.0	440.0	450.0	420.0	580.0
Commercial	65.7	70.0	72.6	71.6	69.2	60.7	70.2
Electricity Generation	128.5	185.0	180.0	195.6	182.2	190.2	207.0
Total	**2,216.2**	**2,136.7**	**1,931.0**	**1,980.7**	**2,010.2**	**2,010.3**	**2,137.8**

Note: Totals may not sum due to independent rounding.

Table 3-62: Ethanol Consumption by Sector (Trillion Btu)

End-Use Sector	1990	2005	2009	2010	2011	2012	2013
Transportation	60.4	327.4	893.9	1,041.4	1,045.0	1,044.6	1,071.5
Industrial	0.8	6.8	12.9	16.6	16.7	16.7	17.6
Commercial	0.5	0.9	2.8	3.3	2.9	2.6	2.7
Total	**61.7**	**335.1**	**909.7**	**1,061.2**	**1,064.6**	**1,063.8**	**1,091.8**

Note: Totals may not sum due to independent rounding.

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 2013. Details on the emission trends through time are described in more detail in the Methodology section, above.

Recalculations Discussion

Wood consumption values were revised relative to the previous Inventory for 2012 based on updated information from EIA's *Monthly Energy Review* (EIA 2015). These revisions of historical data for wood biomass consumption resulted in an average annual increase in emissions from wood biomass consumption of less than 0.1 MMT CO_2 Eq. (less than 0.1 percent) from 1990 through 2012. Total overall ethanol consumption values remained constant relative to the previous inventory for 2012, although there were small differences in historical consumption among the industrial, transportation, and commercial sectors. Consumption increased within the industrial sector and decreased

in the transportation and commercial sectors (EIA 2015), resulting in changes less than 0.1 MMT CO_2 Eq. (less than 0.1 percent) from 1990 through 2012.

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, some facility-level fuel combustion emissions reported under the GHGRP may also include industrial process emissions.[85] In line with UNFCCC reporting guidelines, fuel combustion emissions are included in this chapter, while process emissions are included in the Industrial Processes and Product Use 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.[86]

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

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