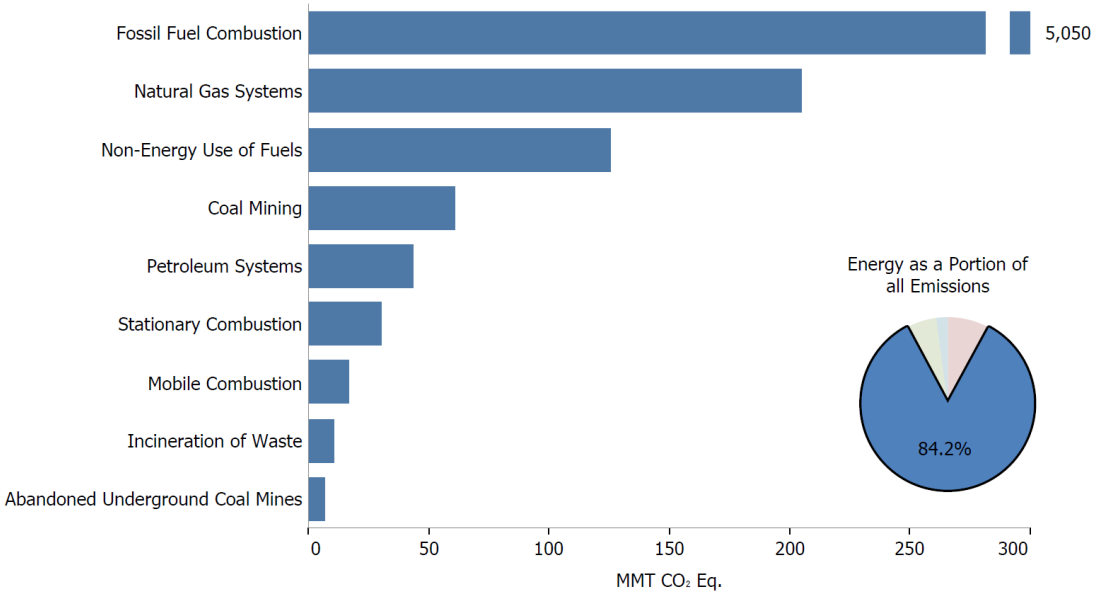
3. Energy

Energy-related activities were the primary sources of U.S. anthropogenic greenhouse gas emissions, accounting for 84.2 percent of total greenhouse gas emissions on a carbon dioxide (CO_2) equivalent basis in 2015.[73] This included 97, 42, 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 79.4 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 (4.8 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 32,381 million metric tons (MMT) of CO_2 were added to the atmosphere through the combustion of fossil fuels in 2014, of which the United States accounted for approximately 16 percent.[74] 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 fourth largest source.

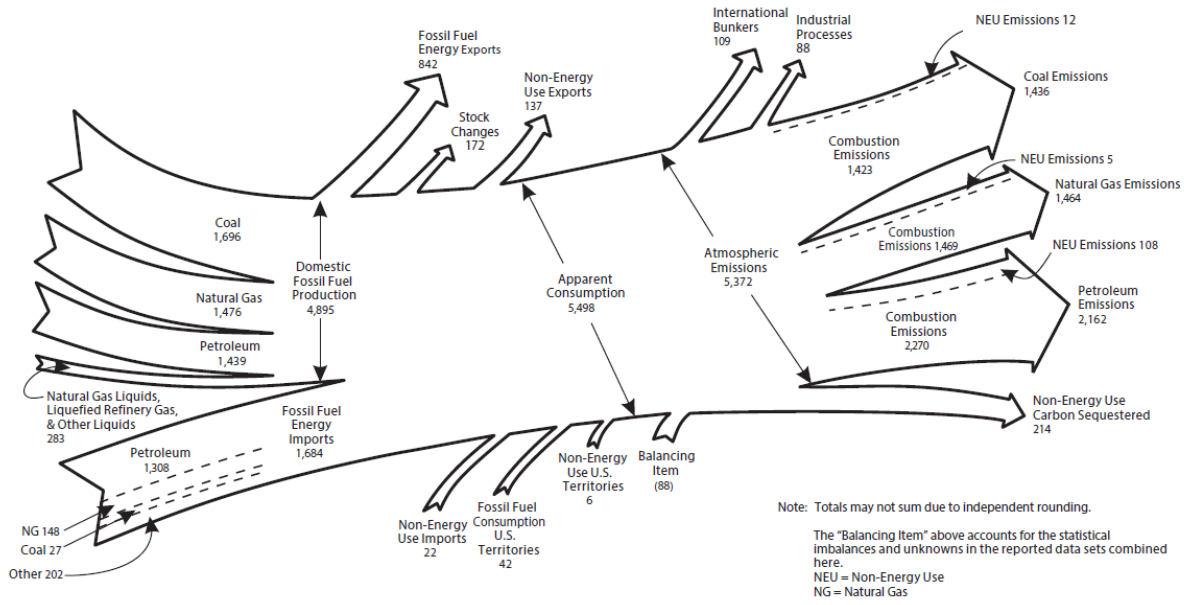
Figure 3-1: 2015 Energy Chapter Greenhouse Gas Sources (MMT CO_2 Eq.)



[73] 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.

[74] Global CO_2 emissions from fossil fuel combustion were taken from International Energy Agency *CO_2 Emissions from Fossil Fuels Combustion – Highlights* <https://www.iea.org/publications/freepublications/publication/co2-emissions-from-fuel-combustion-highlights-2016.html> IEA (2016).

Figure 3-2: 2015 U.S. Fossil Carbon Flows (MMT CO_2 Eq.)



Energy-related activities other than fuel combustion, such as the production, transmission, storage, and distribution of fossil fuels, also emit greenhouse gases. These emissions consist primarily of fugitive CH_4 from natural gas systems, petroleum systems, and coal mining. Table 3-1 summarizes emissions from the Energy sector in units of 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 5,549.1 MMT CO_2 Eq. in 2015,[75] an increase of 4.1 percent since 1990.

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

Gas/Source	1990	2005	2011	2012	2013	2014	2015
CO_2	**4,907.2**	**5,932.3**	**5,387.2**	**5,180.9**	**5,332.7**	**5,377.8**	**5,231.9**
Fossil Fuel Combustion[a]	4,740.3	5,746.9	5,227.1	5,024.6	5,156.5	5,202.3	5,049.8
Electricity Generation	*1,820.8*	*2,400.9*	*2,157.7*	*2,022.2*	*2,038.1*	*2,038.0*	*1,900.7*
Transportation	*1,493.8*	*1,887.0*	*1,707.6*	*1,696.8*	*1,713.0*	*1,742.8*	*1,736.4*
Industrial	*842.5*	*828.0*	*775.0*	*782.9*	*812.2*	*806.1*	*805.5*
Residential	*338.3*	*357.8*	*325.5*	*282.5*	*329.7*	*345.4*	*319.6*
Commercial	*217.4*	*223.5*	*220.4*	*196.7*	*221.0*	*228.7*	*246.2*
U.S. Territories	*27.6*	*49.7*	*40.9*	*43.5*	*42.5*	*41.4*	*41.4*
Non-Energy Use of Fuels	117.6	138.9	109.8	106.7	123.6	119.0	125.5
Natural Gas Systems	37.7	30.1	35.7	35.2	38.5	42.4	42.4
Incineration of Waste	8.0	12.5	10.6	10.4	10.4	10.6	10.7
Petroleum Systems	3.6	3.9	4.2	3.9	3.7	3.6	3.6
Biomass-Wood[b]	*215.2*	*206.9*	*195.2*	*194.9*	*211.6*	*217.7*	*198.7*
International Bunker Fuels[b]	*103.5*	*113.1*	*111.7*	*105.8*	*99.8*	*103.2*	*110.8*
Biofuels-Ethanol[b]	*4.2*	*22.9*	*72.9*	*72.8*	*74.7*	*76.1*	*78.9*
Biofuels-Biodiesel[b]	*0.0*	*0.9*	*8.3*	*8.5*	*13.5*	*13.3*	*14.1*
CH_4	**367.3**	**286.6**	**289.5**	**284.1**	**284.6**	**286.8**	**278.6**
Natural Gas Systems	194.1	159.7	154.5	156.2	159.2	162.5	162.4
Coal Mining	96.5	64.1	71.2	66.5	64.6	64.8	60.9
Petroleum Systems	55.5	46.0	48.0	46.4	44.5	43.0	39.9
Stationary Combustion	8.5	7.4	7.1	6.6	8.0	8.1	7.0

[75] 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.

Abandoned Underground Coal Mines	7.2	6.6	6.4	6.2	6.2	6.3	6.4
Mobile Combustion[a]	5.6	2.8	2.3	2.2	2.1	2.1	2.0
Incineration of Waste	+	+	+	+	+	+	+
International Bunker Fuels[b]	*0.2*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*
N_2O	**53.6**	**56.4**	**44.4**	**42.1**	**41.7**	**40.3**	**38.6**
Stationary Combustion	11.9	20.2	21.3	21.4	22.9	23.4	23.1
Mobile Combustion[a]	41.2	35.7	22.8	20.4	18.5	16.6	15.1
Incineration of Waste	0.5	0.4	0.3	0.3	0.3	0.3	0.3
International Bunker Fuels[b]	*0.9*	*1.0*	*1.0*	*0.9*	*0.9*	*0.9*	*0.9*
Total	**5,328.1**	**6,275.3**	**5,721.2**	**5,507.0**	**5,659.1**	**5,704.9**	**5,549.1**

+ Does not exceed 0.05 MMT CO_2 Eq.

[a] In 2016, FHWA changed its methods for estimating the share of gasoline used in on-road and non-road applications, which created a time-series inconsistency between 2015 and previous years in this Inventory. The method updates are discussed in the Planned Improvements sections of Chapter 3.1 under CO_2 from Fossil Fuel Combustion and CH_4 and N_2O from Mobile Combustion.

[b] 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.

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

Gas/Source	1990	2005	2011	2012	2013	2014	2015
CO_2	**4,907,164**	**5,932,326**	**5,387,235**	**5,180,851**	**5,332,717**	**5,377,822**	**5,231,882**
Fossil Fuel Combustion[a]	4,740,343	5,746,942	5,227,061	5,024,643	5,156,523	5,202,300	5,049,763
Non-Energy Use of Fuels	117,585	138,913	109,756	106,750	123,645	118,995	125,526
Natural Gas Systems	37,732	30,076	35,662	35,203	38,457	42,351	42,351
Incineration of Waste	7,950	12,469	10,564	10,379	10,398	10,608	10,676
Petroleum Systems	3,553	3,927	4,192	3,876	3,693	3,567	3,567
Biomass-Wood[b]	*215,186*	*206,901*	*195,182*	*194,903*	*211,581*	*217,654*	*198,723*
International Bunker Fuels[b]	*103,463*	*113,139*	*111,660*	*105,805*	*99,763*	*103,201*	*110,751*
Biofuels-Ethanol[b]	*4,227*	*22,943*	*72,881*	*72,827*	*74,743*	*76,075*	*78,934*
Biofuels-Biodiesel[b]	*0*	*856*	*8,349*	*8,470*	*13,462*	*13,349*	*14,077*
CH_4	**14,693**	**11,464**	**11,581**	**11,364**	**11,385**	**11,473**	**11,145**
Natural Gas Systems	7,762	6,387	6,180	6,247	6,368	6,501	6,497
Coal Mining	3,860	2,565	2,849	2,658	2,584	2,593	2,436
Petroleum Systems	2,218	1,840	1,922	1,858	1,778	1,721	1,595
Stationary Combustion	339	296	283	265	320	323	280
Abandoned Underground Coal Mines	288	264	257	249	249	253	256
Mobile Combustion[a]	226	113	91	87	85	82	80
Incineration of Waste	+	+	+	+	+	+	+
International Bunker Fuels[b]	*7*	*5*	*5*	*4*	*3*	*3*	*3*
N_2O	**180**	**189**	**149**	**141**	**140**	**135**	**129**
Stationary Combustion	40	68	71	72	77	78	78
Mobile Combustion[a]	138	120	77	68	62	56	51
Incineration of Waste	2	1	1	1	1	1	1
International Bunker Fuels[b]	*3*	*3*	*3*	*3*	*3*	*3*	*3*

+ Does not exceed 0.5 kt

[a] In 2016, FHWA changed its methods for estimating the share of gasoline used in on-road and non-road applications, which created a time-series inconsistency between 2015 and previous years in this Inventory. The method updates are discussed in the Planned Improvements sections of Chapter 3.1 under CO_2 from Fossil Fuel Combustion and CH_4 and N_2O from Mobile Combustion.

[b] 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.

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

In following the United Nations Framework Convention on Climate Change (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 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 EPA's 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 from large greenhouse gas 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.

EPA's GHGRP dataset and the data presented in this Inventory report are complementary. The GHGRP dataset continues to be an important resource for the Inventory, providing not only annual emissions information, but also other annual information, such as activity data and emission factors that can improve and refine national emission estimates and trends over time. GHGRP data also allow EPA to disaggregate national inventory estimates in new ways that can highlight differences across regions and sub-categories of emissions, along with enhancing application of QA/QC procedures and assessment of uncertainties.

EPA uses annual GHGRP data in a number of category estimates and continues to analyze the data on an annual basis, as applicable, for further use to improve the national estimates presented in this Inventory consistent with IPCC guidance (see, also, Box 3-4).[76]As indicated in the respective Planned Improvements sections for source categories in this chapter, EPA is considering further use of facility-level GHGRP data to improve the national estimates presented in this Inventory. 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.[77]

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.[78]

One area where the GHGRP fuel consumption activity data is used in the Energy sector is in disaggregating industrial end-use sector emissions in the category of CO_2 Emissions from Fossil Fuel Combustion, for use in reporting emissions in Common Reporting Format (CRF) tables. The industrial end-use sector activity data

[76] See <http://www.ipcc-nggip.iges.or.jp/public/tb/TFI_Technical_Bulletin_1.pdf>.

[77] See <http://www.ccdsupport.com/confluence/display/ghgp/Detailed+Description+of+Data+for+Certain+Sources+and+Processes>.

[78] See <http://ghgdata.epa.gov>.

collected for the Inventory (EIA 2017a) represent aggregated data for the industrial end-use sector. EPA's GHGRP collects industrial fuel consumption activity data by individual categories within the industrial end-use sector. Therefore, the GHGRP data is used to provide a more detailed breakout of total emissions in the industrial end-use sector within that source category.

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	2011	2012	2013	2014	2015
CO_2	4,740.3	5,746.9	5,227.1	5,024.6	5,156.5	5,202.3	5,049.8
CH_4	14.1	10.2	9.3	8.8	10.1	10.1	9.0
N_2O	53.1	56.0	44.1	41.7	41.4	40.0	38.2
Total	**4,807.6**	**5,813.1**	**5,280.5**	**5,075.2**	**5,208.1**	**5,252.4**	**5,097.0**

Note: Totals may not sum due to independent rounding

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

Gas	1990	2005	2011	2012	2013	2014	2015
CO_2	4,740,343	5,746,942	5,227,061	5,024,643	5,156,523	5,202,300	5,049,763
CH_4	565	408	374	352	405	405	361
N_2O	178	188	148	140	139	134	128

CO_2 from Fossil Fuel Combustion

Carbon dioxide is the primary gas emitted from fossil fuel combustion and represents the largest share of U.S. total greenhouse gas emissions. Carbon dioxide emissions from fossil fuel combustion are presented in Table 3-5. In 2015, CO_2 emissions from fossil fuel combustion decreased by 2.9 percent relative to the previous year. The decrease in CO_2 emissions from fossil fuel combustion was a result of multiple factors, including: (1) substitution from coal to natural gas consumption in the electric power sector; (2) warmer winter conditions in 2015 resulting in a decreased demand for heating fuel in the residential and commercial sectors; and (3) a slight decrease in electricity demand. In 2015, CO_2 emissions from fossil fuel combustion were 5,049.8 MMT CO_2 Eq., or 6.5 percent above emissions in 1990 (see Table 3-5).[79]

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

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

Fuel/Sector	1990	2005	2011	2012	2013	2014	2015
Coal	**1,718.4**	**2,112.3**	**1,813.9**	**1,592.8**	**1,653.8**	**1,652.6**	**1,423.3**
Residential	3.0	0.8	NO	NO	NO	NO	NO
Commercial	12.0	9.3	5.8	4.1	3.9	3.8	2.9
Industrial	155.3	115.3	82.0	74.1	75.7	75.6	65.9
Transportation	NE	NE	NE	NE	NE	NE	NE
Electricity Generation	1,547.6	1,983.8	1,722.7	1,511.2	1,571.3	1,569.1	1,350.5
U.S. Territories	0.6	3.0	3.4	3.4	2.8	4.0	4.0
Natural Gas	**1,000.3**	**1,166.7**	**1,291.5**	**1,352.6**	**1,391.2**	**1,422.0**	**1,463.6**
Residential	238.0	262.2	254.7	224.8	266.2	277.9	252.8
Commercial	142.1	162.9	170.5	156.9	179.1	189.3	175.4
Industrial	408.9	388.5	417.3	434.8	451.9	468.4	467.5
Transportation	36.0	33.1	38.9	41.3	47.0	40.3	38.8
Electricity Generation	175.3	318.8	408.8	492.2	444.0	443.2	526.1
U.S. Territories	NO	1.3	1.4	2.6	3.0	3.0	3.0
Petroleum[a]	**2,021.2**	**2,467.6**	**2,121.3**	**2,078.8**	**2,111.1**	**2,127.3**	**2,162.5**
Residential	97.4	94.9	70.9	57.7	63.4	67.5	66.8
Commercial	63.3	51.3	44.1	35.7	38.0	35.6	67.9
Industrial	278.3	324.2	275.7	274.1	284.6	262.1	272.2
Transportation	1,457.7	1,854.0	1,668.8	1,655.4	1,666.0	1,702.5	1,697.6
Electricity Generation	97.5	97.9	25.8	18.3	22.4	25.3	23.7
U.S. Territories	26.9	45.4	36.0	37.5	36.6	34.3	34.3
Geothermal[b]	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**
Total	**4,740.3**	**5,746.9**	**5,227.1**	**5,024.6**	**5,156.5**	**5,202.3**	**5,049.8**

+ Does not exceed 0.05 MMT CO_2 Eq.
NE (Not Estimated)
NO (Not Occurring)
[a] In 2016, FHWA changed its methods for estimating the share of gasoline used in on-road and non-road applications, which created a time-series inconsistency between 2015 and previous years in this Inventory. The method changes resulted in a decrease in the estimated motor gasoline consumption for the transportation sector and a subsequent increase in the commercial and industrial sectors of this Inventory for 2015. The method updates are discussed further in the Planned Improvements section below under CO_2 from Fossil Fuel Combustion.
[b] 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).

Carbon dioxide 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.[80] 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 2015 Emissions from Fossil Fuel Combustion for Selected Fuels and Sectors (MMT CO_2 Eq. and Percent)

Sector	Fuel Type	2011 to 2012		2012 to 2013		2013 to 2014		2014 to 2015		Total 2015
Electricity Generation	Coal	-211.5	-12.3%	60.1	4.0%	-2.2	-0.1%	-218.7	-13.9%	1,350.5
Electricity Generation	Natural Gas	83.5	20.4%	-48.3	-9.8%	-0.8	-0.2%	82.9	18.7%	526.1
Electricity Generation	Petroleum	-7.5	-29.0%	4.1	22.3%	2.9	12.8%	-1.6	-6.4%	23.7
Residential	Natural Gas	-29.8	-11.7%	41.4	18.4%	11.6	4.4%	-25.1	-9.0%	252.8
Commercial	Natural Gas	-13.6	-8.0%	22.3	14.2%	10.2	5.7%	-13.9	-7.4%	175.4
Industrial	Coal	-7.9	-9.7%	1.7	2.3%	-0.1	-0.1%	-9.8	-12.9%	65.9
Industrial	Natural Gas	17.5	4.2%	17.1	3.9%	16.5	3.7%	-0.9	-0.2%	467.5
All Sectors[a]	**All Fuels[a]**	**-202.4**	**-3.9%**	**131.9**	**2.6%**	**45.8**	**0.9%**	**-152.5**	**-2.9%**	**5,049.8**

[a] Includes fuels and sectors not shown in table.

Note: Totals may not sum due to independent rounding.

As shown in Table 3-6, recent trends in CO_2 emissions from fossil fuel combustion show a 3.9 percent decrease from 2011 to 2012, then a 2.6 percent and a 0.9 percent increase from 2012 to 2013 and 2013 to 2014, respectively, and a 2.9 percent decrease from 2014 to 2015. Total electricity generation remained relatively flat over that time period but emission trends generally mirror the trends in the amount of coal used to generate electricity. The consumption of coal used to generate electricity decreased by roughly 12 percent from 2011 to 2012, increased by 4 percent from 2012 to 2013, stayed relatively flat from 2013 to 2014, and decreased by 14 percent from 2014 to 2015. The overall CO_2 emission trends from fossil fuel combustion also follow closely changes in heating degree days over that time period. Heating degree days decreased by 13 percent from 2011 to 2012, increased by 18 percent from 2012 to 2013, increased by 2 percent from 2013 to 2014 and decreased by 10 percent from 2014 to 2015. A decrease in heating degree days leads to decreased demand for heating fuel and electricity for heat in the residential and commercial sector, primarily in winter months. The overall CO_2 emission trends from fossil fuel combustion also generally follow changes in overall petroleum use and emissions. CO_2 emissions from petroleum decreased by 2.0 percent from 2011 to 2012, increased by 1.6 percent from 2012 to 2013, increased by 0.8 percent from 2013 to 2014, and increased by 1.7 percent from 2014 to 2015. The increase in petroleum CO_2 emissions from 2014 to 2015 somewhat offsets emission reductions from other sources like decreased coal use in the electricity sector.

In the United States, 82 percent of the energy consumed in 2015 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 2017a).[81] Specifically, petroleum supplied the largest share of domestic energy demands, accounting for 37 percent of total U.S. energy consumption in 2015. Natural gas and coal followed in order of energy demand importance, accounting for approximately 29 percent and 16 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 2017a).

CO_2 emissions from motor gasoline consumption are 23 percent of the CO_2 emissions from fossil fuel combustion. The majority of gasoline is used in the transportation sector. Note that a method update in the current Inventory impacted the allocation of gasoline between the transportation, commercial, and industrial sectors in 2015,

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

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

however overall gasoline use, trends, and CO_2 emissions were not impacted.[82] The recent trend since 2012 is an increase in total gasoline use and CO_2 emissions (see Figure 3-6).

Figure 3-3: 2015 U.S. Energy Consumption by Energy Source (Percent)

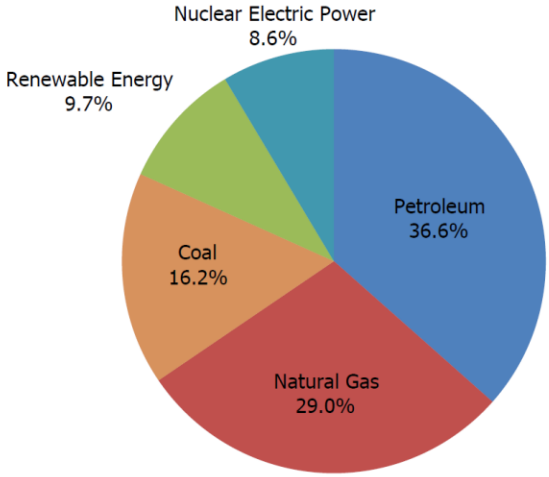
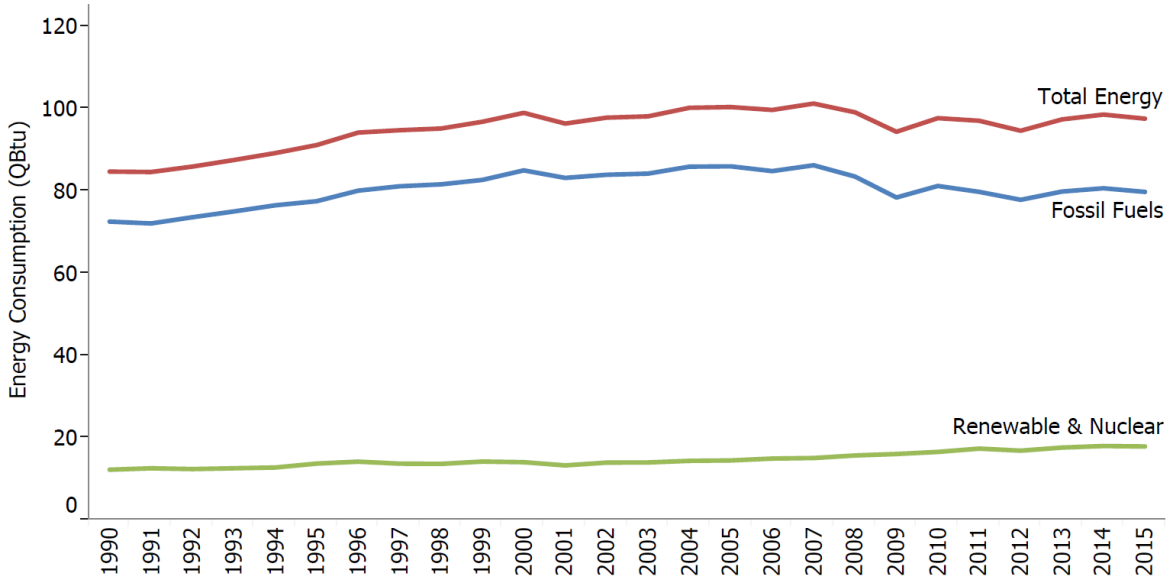


Figure 3-4: U.S. Energy Consumption (Quadrillion Btu)



[82] In 2016, FHWA changed its methods for estimating the share of gasoline used in on-road and non-road applications, which created a time-series inconsistency between 2015 and previous years in this Inventory. The method changes resulted in a decrease in the estimated motor gasoline consumption for the transportation sector and a subsequent increase in the commercial and industrial sectors of this Inventory for 2015. The method updates are discussed further in the *Planned Improvements* section below under *CO_2 from Fossil Fuel Combustion.*

Figure 3-5: 2015 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type (MMT CO_2 Eq.)

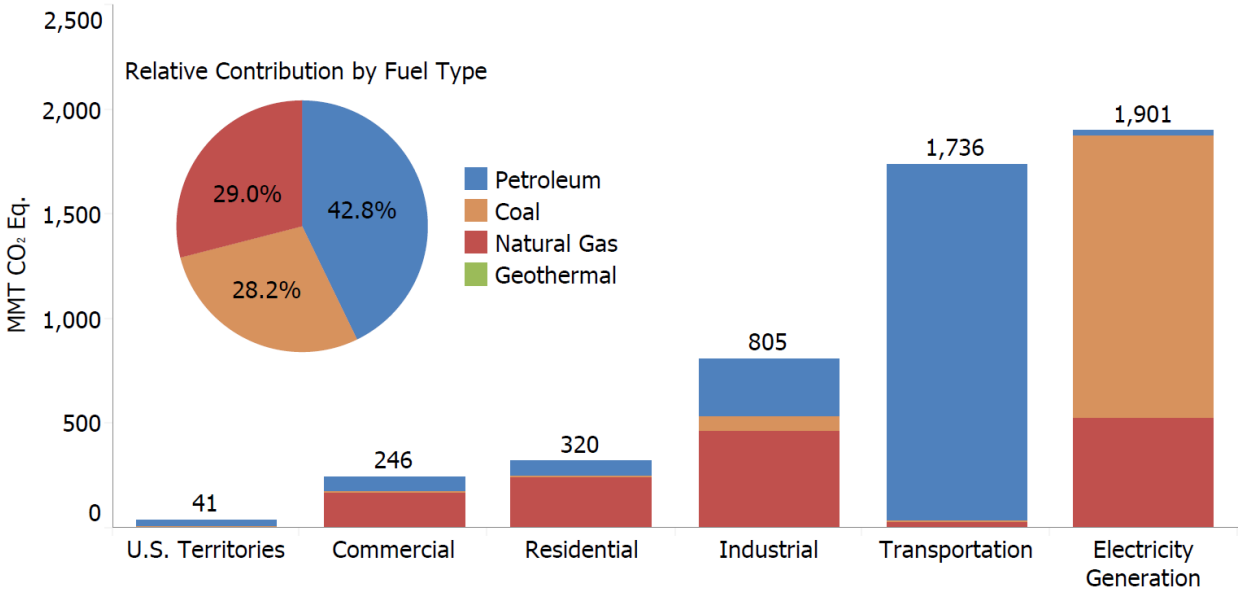
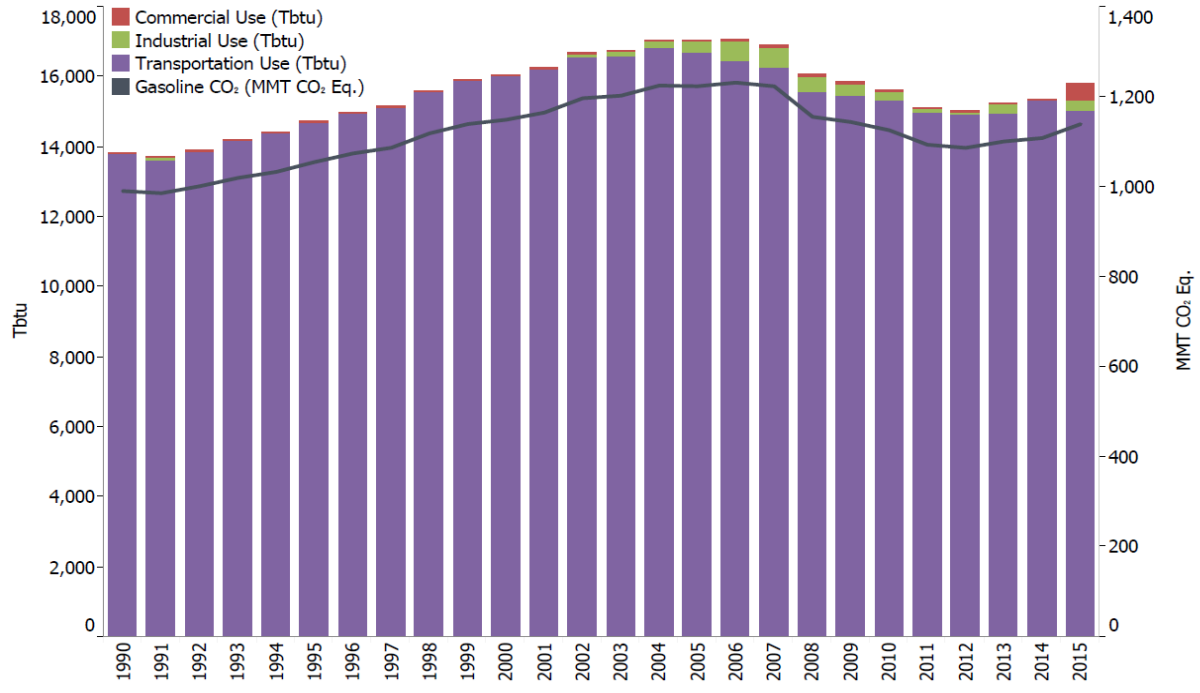


Figure 3-6: U.S. Gasoline Consumption (Tbtu) and CO_2 Emissions by Sector (MMT CO_2 Eq.)



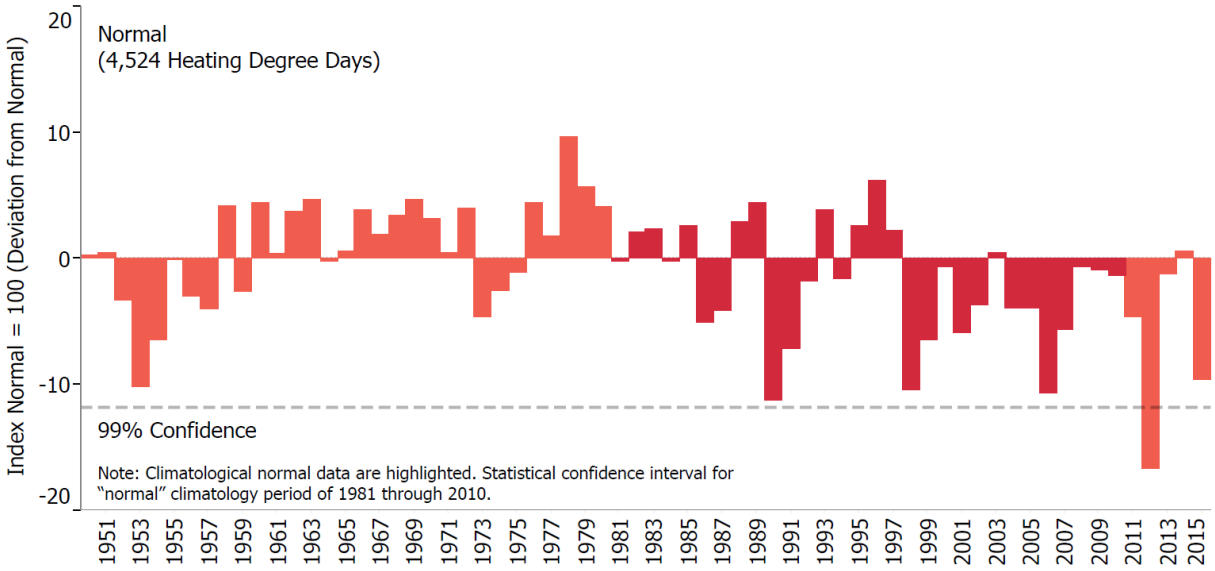
Fossil fuels are generally combusted for the purpose of producing energy for useful heat and work. During the combustion process, the C stored in the fuels is oxidized and emitted as CO_2 and smaller amounts of other gases,

including CH_4, CO, and NMVOCs.[83] 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 2015, weather conditions, and a warm first and fourth quarter of the year in particular, caused a significant decrease in demand for heating fuels and is reflected in the decreased residential emissions from 2014 to 2015. The United States in 2015 also experienced a warmer winter overall compared to 2014, as heating degree days decreased (10.2 percent). Warmer winter conditions compared to 2014 resulted in a decrease in the amount of energy required for heating, and heating degree days in the United States were 9.7 percent below normal (see Figure 3-7). Cooling degree days increased significantly, by 14.6 percent, and despite this increase in cooling degree days, which typically leads to increased demand for air conditioning in the residential and commercial sector, residential electricity demand decreased slightly. Summer conditions were significantly warmer in 2015 compared to 2014, with cooling degree days 22.5 percent above normal (see Figure 3-8) (EIA 2017a).[84]

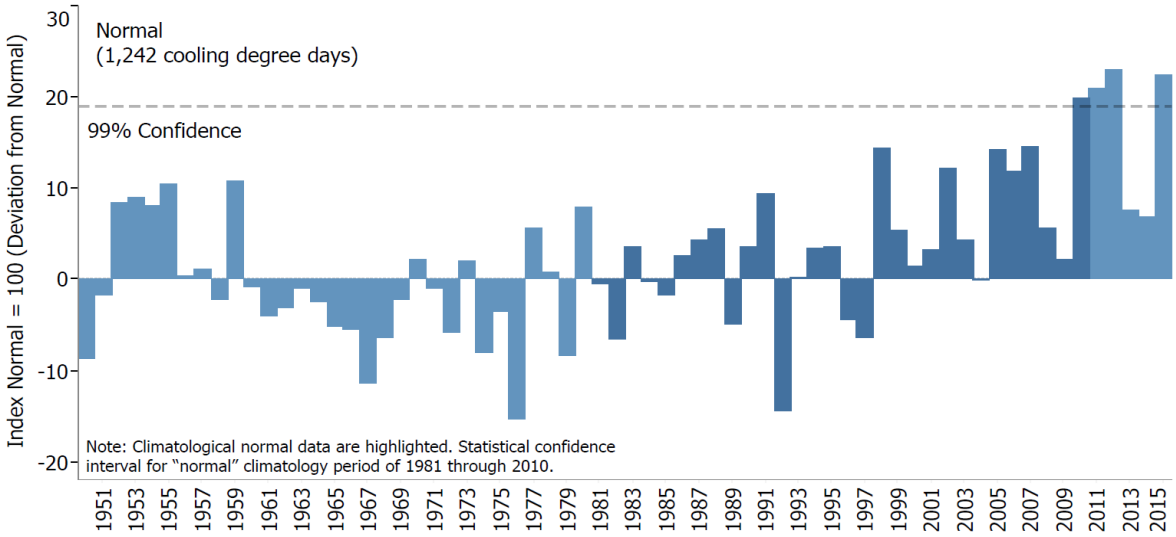
Figure 3-7: Annual Deviations from Normal Heating Degree Days for the United States (1950–2015, Index Normal = 100)



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

[84] Degree days are relative measurements of outdoor air temperature. Heating degree days are deviations of the mean daily temperature below 65 degrees Fahrenheit, while cooling degree days are deviations of the mean daily temperature above 65 degrees Fahrenheit. 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).

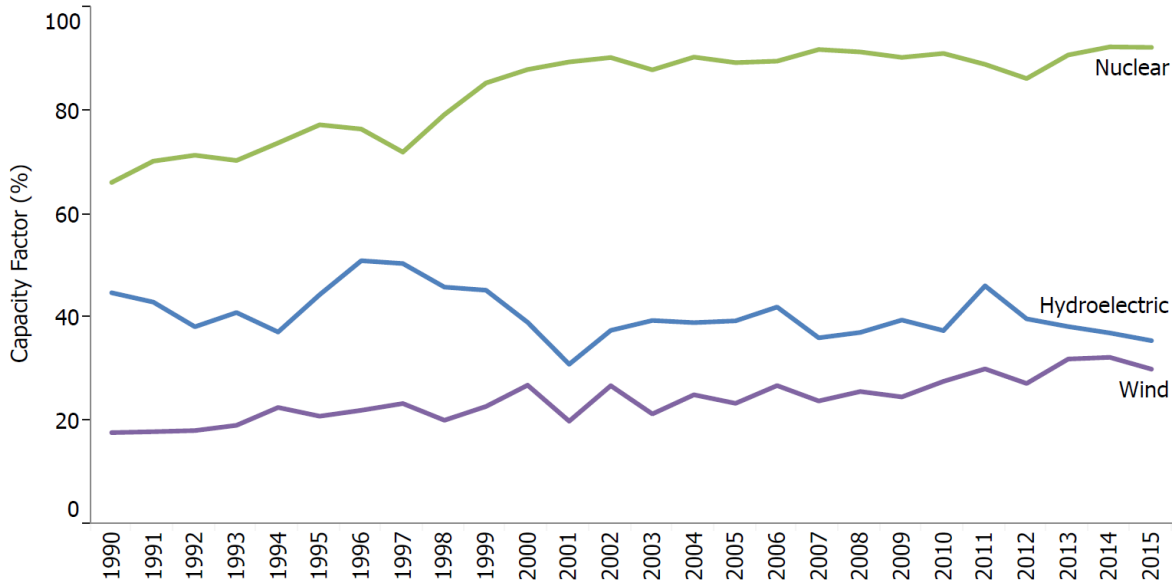
Figure 3-8: Annual Deviations from Normal Cooling Degree Days for the United States (1950–2015, Index Normal = 100)



Although no new U.S. nuclear power plants were brought online in 2015, the utilization (i.e., capacity factors)[85] of existing plants in 2015 remained high at 92 percent. Electricity output by hydroelectric power plants decreased in 2015 by approximately 4 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 2015 provided more than 3 times as much of the energy generated in the United States from hydroelectric plants (EIA 2016a). Nuclear, hydroelectric, and wind power capacity factors since 1990 are shown in Figure 3-9.

[85] 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 (2016a).

Figure 3-9: Nuclear, Hydroelectric, and Wind Power Plant Capacity Factors in the United States (1990–2015, Percent)



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	2011	2012	2013	2014	2015
Electricity Generation	**1,828.5**	**2,417.3**	**2,175.7**	**2,040.4**	**2,057.7**	**2,058.0**	**1,920.6**
CO_2	1,820.8	2,400.9	2,157.7	2,022.2	2,038.1	2,038.0	1,900.7
CH_4	0.3	0.5	0.4	0.4	0.4	0.4	0.4
N_2O	7.4	16.0	17.6	17.8	19.1	19.6	19.5
Transportation[a]	**1,540.6**	**1,925.6**	**1,732.7**	**1,719.3**	**1,733.6**	**1,761.5**	**1,753.5**
CO_2	1,493.8	1,887.0	1,707.6	1,696.8	1,713.0	1,742.8	1,736.4
CH_4	5.6	2.8	2.3	2.2	2.1	2.1	2.0
N_2O	41.2	35.7	22.8	20.4	18.5	16.6	15.1
Industrial[a]	**847.4**	**832.6**	**778.9**	**786.9**	**816.2**	**810.0**	**809.3**
CO_2	842.5	828.0	775.0	782.9	812.2	806.1	805.5
CH_4	1.8	1.7	1.5	1.5	1.5	1.5	1.5
N_2O	3.1	2.9	2.4	2.4	2.4	2.4	2.4
Residential	**344.6**	**362.8**	**330.4**	**287.0**	**335.6**	**351.3**	**324.3**
CO_2	338.3	357.8	325.5	282.5	329.7	345.4	319.6
CH_4	5.2	4.1	4.0	3.7	5.0	5.0	3.9
N_2O	1.0	0.9	0.8	0.7	1.0	1.0	0.8
Commercial[a]	**218.8**	**224.9**	**221.7**	**197.9**	**222.4**	**230.0**	**247.8**
CO_2	217.4	223.5	220.4	196.7	221.0	228.7	246.2
CH_4	1.0	1.1	1.0	0.9	1.0	1.1	1.2
N_2O	0.4	0.3	0.3	0.3	0.3	0.3	0.4

U.S. Territories[b]	**27.7**	**49.9**	**41.0**	**43.7**	**42.6**	**41.5**	**41.5**
Total	**4,807.6**	**5,813.1**	**5,280.5**	**5,075.2**	**5,208.1**	**5,252.4**	**5,097.0**

[a] In 2016, FHWA changed its methods for estimating the share of gasoline used in on-road and non-road applications, which created a time-series inconsistency between 2015 and previous years in this Inventory. The method changes resulted in a decrease in the estimated motor gasoline consumption for the transportation sector and a subsequent increase in the commercial and industrial sectors of this Inventory for 2015. The method updates are discussed further in the Planned Improvements section below under CO_2 from Fossil Fuel Combustion.

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

Notes: 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.

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.[86] 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. Nitrous oxide 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.[87] 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	2011	2012	2013	2014	2015
Transportation[a]	**1,543.7**	**1,930.4**	**1,737.0**	**1,723.2**	**1,737.7**	**1,765.6**	**1,757.3**
CO_2	1,496.8	1,891.8	1,711.9	1,700.6	1,717.0	1,746.9	1,740.1
CH_4	5.6	2.8	2.3	2.2	2.1	2.1	2.0
N_2O	41.2	35.8	22.9	20.4	18.5	16.6	15.2
Industrial[a]	**1,537.0**	**1,574.2**	**1,408.8**	**1,385.0**	**1,416.6**	**1,409.0**	**1,364.6**
CO_2	1,529.2	1,564.6	1,399.6	1,375.7	1,407.0	1,399.3	1,355.0

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

[87] 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.

CH_4	2.0	1.9	1.6	1.6	1.6	1.6	1.6
N_2O	5.9	7.8	7.5	7.7	8.0	8.1	8.0
Residential	**940.2**	**1,224.9**	**1,127.7**	**1,018.8**	**1,077.5**	**1,093.3**	**1,015.7**
CO_2	931.4	1,214.1	1,116.2	1,007.8	1,064.6	1,080.1	1,003.9
CH_4	5.4	4.2	4.2	3.9	5.1	5.2	4.0
N_2O	3.4	6.6	7.3	7.1	7.9	8.0	7.8
Commercial[a]	**759.1**	**1,033.7**	**966.0**	**904.5**	**933.6**	**943.0**	**917.9**
CO_2	755.4	1,026.8	958.4	897.0	925.5	934.7	909.4
CH_4	1.1	1.2	1.2	1.1	1.2	1.2	1.3
N_2O	2.5	5.7	6.3	6.4	6.9	7.1	7.2
U.S. Territories[b]	**27.7**	**49.9**	**41.0**	**43.7**	**42.6**	**41.5**	**41.5**
Total	**4,807.6**	**5,813.1**	**5,280.5**	**5,075.2**	**5,208.1**	**5,252.4**	**5,097.0**

[a] In 2016, FHWA changed its methods for estimating the share of gasoline used in on-road and non-road applications, which created a time-series inconsistency between 2015 and previous years in this Inventory. The method changes resulted in a decrease in the estimated motor gasoline consumption for the transportation sector and a subsequent increase in the commercial and industrial sectors of this Inventory for 2015. The method updates are discussed further in the Planned Improvements section below under CO_2 from Fossil Fuel Combustion.

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

Notes: 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.

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.[88] 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. Nitrous oxide 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 for the 1990 through 2008 Inventory to utilize the facility-specific technology and fuel use data reported to EPA's Acid Rain Program (EPA 2016a) (see Methodology section for CH_4 and N_2O from Stationary Combustion). Table 3-7 presents the corresponding direct CO_2, CH_4, and N_2O emissions from all sources of fuel combustion, without allocating emissions from electricity consumption to the end-use sectors.

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

Sector/Fuel Type	1990	2005	2011	2012	2013	2014	2015
Electricity Generation	**1,820.8**	**2,400.9**	**2,157.7**	**2,022.2**	**2,038.1**	**2,038.0**	**1,900.7**
Coal	1,547.6	1,983.8	1,722.7	1,511.2	1,571.3	1,569.1	1,350.5
Natural Gas	175.3	318.8	408.8	492.2	444.0	443.2	526.1
Fuel Oil	97.5	97.9	25.8	18.3	22.4	25.3	23.7
Geothermal	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Industrial	**842.5**	**828.0**	**775.0**	**782.9**	**812.2**	**806.1**	**805.5**
Coal	155.3	115.3	82.0	74.1	75.7	75.6	65.9
Natural Gas	408.9	388.5	417.3	434.8	451.9	468.4	467.5

[88] 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.

Fuel Oil[a]	278.3	324.2	275.7	274.1	284.6	262.1	272.2
Commercial	**217.4**	**223.5**	**220.4**	**196.7**	**221.0**	**228.7**	**246.2**
Coal	12.0	9.3	5.8	4.1	3.9	3.8	2.9
Natural Gas	142.1	162.9	170.5	156.9	179.1	189.3	175.4
Fuel Oil[a]	63.3	51.3	44.1	35.7	38.0	35.6	67.9
Residential	**338.3**	**357.8**	**325.5**	**282.5**	**329.7**	**345.4**	**319.6**
Coal	3.0	0.8	NO	NO	NO	NO	NO
Natural Gas	238.0	262.2	254.7	224.8	266.2	277.9	252.8
Fuel Oil	97.4	94.9	70.9	57.7	63.4	67.5	66.8
U.S. Territories	**27.6**	**49.7**	**40.9**	**43.5**	**42.5**	**41.4**	**41.4**
Coal	0.6	3.0	3.4	3.4	2.8	4.0	4.0
Natural Gas	NO	1.3	1.4	2.6	3.0	3.0	3.0
Fuel Oil	26.9	45.4	36.0	37.5	36.6	34.3	34.3
Total	**3,246.6**	**3,859.9**	**3,519.4**	**3,327.9**	**3,443.5**	**3,459.5**	**3,313.4**

+ Does not exceed 0.05 MMT CO_2 Eq.

NO (Not Occurring)

[a] In 2016, FHWA changed its methods for estimating the share of gasoline used in on-road and non-road applications, which created a time-series inconsistency between 2015 and previous years in the current Inventory. The method changes resulted in a decrease in the estimated motor gasoline consumption for the transportation sector and a subsequent increase in the commercial and industrial sectors of this Inventory for 2015. The methodology updates are discussed further in the Planned Improvements section below under CO_2 from Fossil Fuel Combustion.

Note: Totals may not sum due to independent rounding.

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

Sector/Fuel Type	1990	2005	2011	2012	2013	2014	2015
Electric Power	**0.3**	**0.5**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**
Coal	0.3	0.3	0.3	0.2	0.2	0.2	0.2
Fuel Oil	+	+	+	+	+	+	+
Natural gas	0.1	0.1	0.2	0.2	0.2	0.2	0.2
Wood	+	+	+	+	+	+	+
Industrial	**1.8**	**1.7**	**1.5**	**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	0.1	0.2	0.1	0.1
Natural gas	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Wood	1.0	1.0	0.9	1.0	0.9	0.9	0.9
Commercial	**1.0**	**1.1**	**1.0**	**0.9**	**1.0**	**1.1**	**1.2**
Coal	+	+	+	+	+	+	+
Fuel Oil	0.2	0.2	0.2	0.1	0.1	0.1	0.2
Natural gas	0.3	0.4	0.4	0.4	0.4	0.4	0.4
Wood	0.5	0.5	0.5	0.4	0.5	0.5	0.5
Residential	**5.2**	**4.1**	**4.0**	**3.7**	**5.0**	**5.0**	**3.9**
Coal	0.2	0.1	NO	NO	NO	NO	NO
Fuel Oil	0.3	0.3	0.3	0.2	0.2	0.2	0.2
Natural Gas	0.5	0.6	0.6	0.5	0.6	0.6	0.6
Wood	4.1	3.1	3.2	3.0	4.1	4.1	3.1
U.S. Territories	**+**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Coal	+	+	+	+	+	+	+
Fuel Oil	+	0.1	0.1	0.1	0.1	0.1	0.1
Natural Gas	NO	+	+	+	+	+	+
Wood	NO	NO	NO	NO	NO	NO	NO
Total	**8.5**	**7.4**	**7.1**	**6.6**	**8.0**	**8.1**	**7.0**

+ Does not exceed 0.05 MMT CO_2 Eq.

NO (Not Occurring)

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	2011	2012	2013	2014	2015
Electricity Generation	**7.4**	**16.0**	**17.6**	**17.8**	**19.1**	**19.6**	**19.5**
Coal	6.3	11.6	11.5	10.2	12.1	12.4	11.0
Fuel Oil	0.1	0.1	+	+	+	+	+
Natural Gas	1.0	4.3	6.1	7.5	7.0	7.2	8.4
Wood	+	+	+	+	+	+	+
Industrial	**3.1**	**2.9**	**2.4**	**2.4**	**2.4**	**2.4**	**2.4**
Coal	0.7	0.5	0.4	0.4	0.4	0.4	0.3
Fuel Oil	0.5	0.5	0.4	0.3	0.4	0.3	0.3
Natural Gas	0.2	0.2	0.2	0.2	0.2	0.3	0.2
Wood	1.6	1.6	1.5	1.5	1.5	1.5	1.5
Commercial	**0.4**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.4**
Coal	0.1	+	+	+	+	+	+
Fuel Oil	0.2	0.1	0.1	0.1	0.1	0.1	0.2
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**	**0.8**	**0.7**	**1.0**	**1.0**	**0.8**
Coal	+	+	NO	NO	NO	NO	NO
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	0.5	0.5	0.7	0.7	0.5
U.S. Territories	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Coal	+	+	+	+	+	+	+
Fuel Oil	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Natural Gas	NO	+	+	+	+	+	+
Wood	NO	NO	NO	NO	NO	NO	NO
Total	**11.9**	**20.2**	**21.3**	**21.4**	**22.9**	**23.4**	**23.1**

+ Does not exceed 0.05 MMT CO_2 Eq.
NO (Not Occurring)
Note: Totals may not sum due to independent rounding.

Electricity Generation

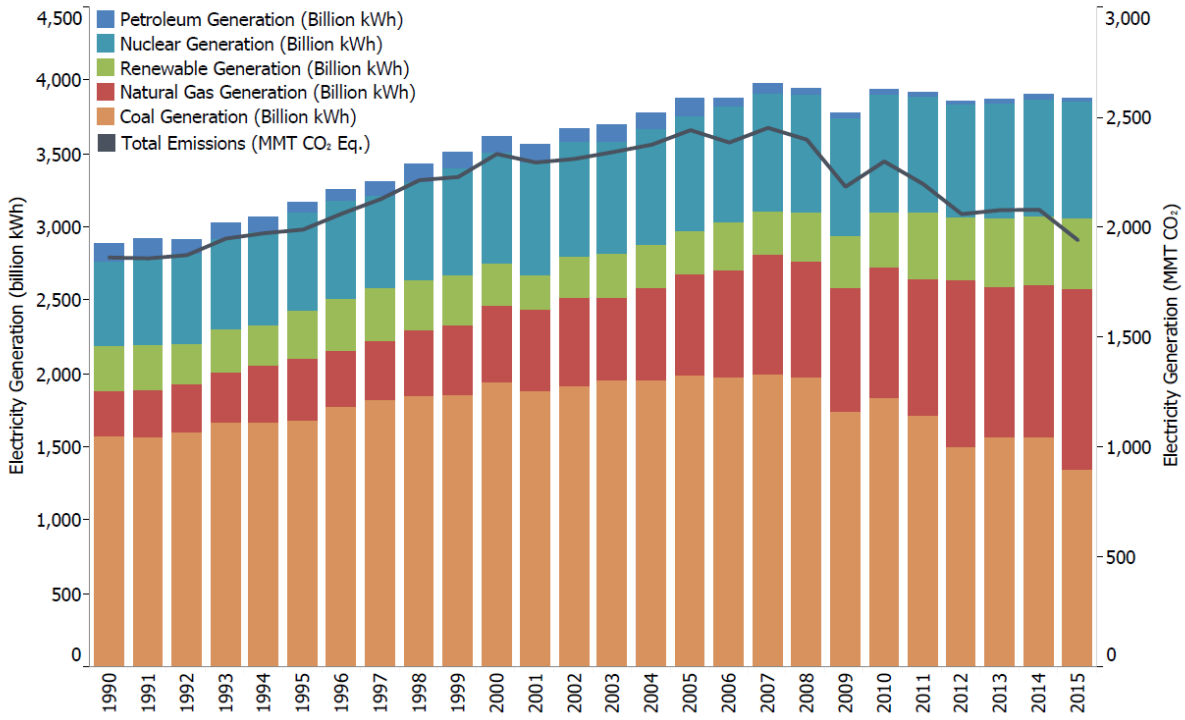
The process of generating electricity is the single largest source of CO_2 emissions in the United States, representing 35 percent of total CO_2 emissions from all CO_2 emissions sources across the United States. Methane and N_2O accounted for a small portion of emissions from electricity generation, representing less than 0.1 percent and 1.0 percent, respectively. Electricity generation also accounted for the largest share of CO_2 emissions from fossil fuel combustion, approximately 37.6 percent in 2015. Methane and N_2O from electricity generation represented 4.9 and 51.0 percent of total CH_4 and N_2O emissions from fossil fuel combustion in 2015, respectively.

While emissions from the electric power sector have increased by 4 percent since 1990, the carbon intensity of the electric power sector, in terms of CO_2 Eq. per QBtu has significantly decreased by 16 percent during that same timeframe. This decarbonization of the electric power sector is a result of several key drivers. Coal-fired electricity generation (in kilowatt-hours [kWh]) decreased from almost 54 percent of generation in 1990 to 34 percent in 2015. This generation corresponded with an increase in natural gas and renewable energy generation, largely from wind and solar energy. Natural gas generation (in kWh) represented 11 percent of electric power generation in 1990, and increased over the 26 year period to represent 32 percent of electric power generation in 2015. This decoupling of electricity generation and the resulting emissions is shown below in Figure 3-10.

Decreases in natural gas costs and the associated increase in natural gas generation, particularly between 2005 and 2015, was the main driver of the decrease in electric power sector carbon intensity. During this time period, the cost of natural gas (in $/MMBtu) decreased by 51 percent while the cost of coal (in $/MMBtu) increased by 91 percent (EIA 2017a). Between 1990 and 2015, renewable energy generation (in kWh) from solar and wind energy have increased from 0.1 percent in 1990 to 5 percent in 2015, which also helped drive the decreases in the carbon

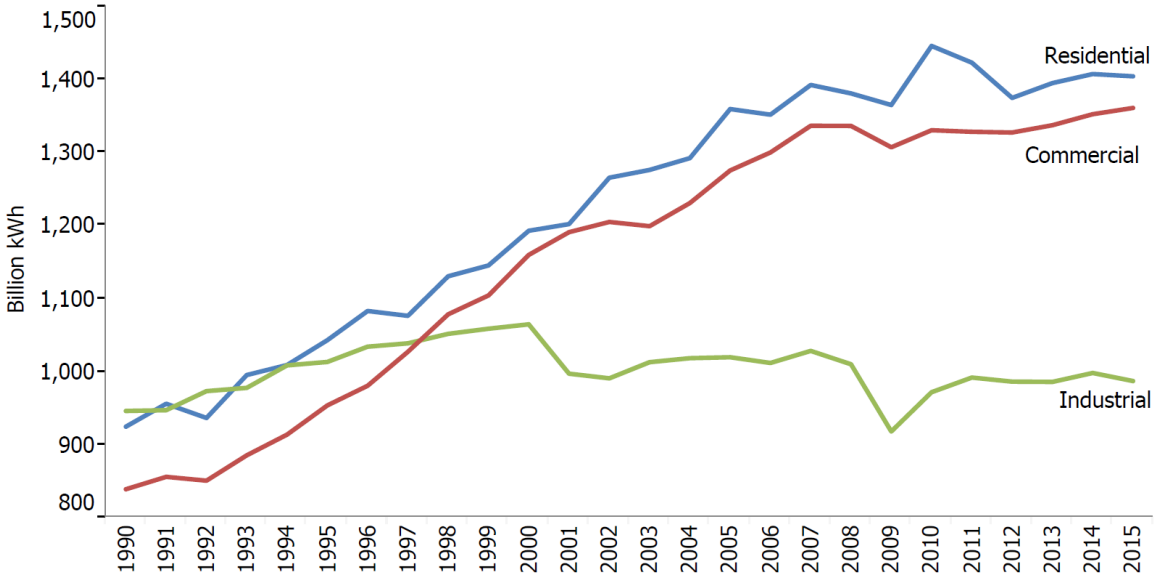
intensity of the electricity supply in the United States. This decrease in carbon intensity occurred even as total electricity retail sales increased 39 percent, from 2,713 billion kWh in 1990 to 3,759 billion kWh in 2015.

Figure 3-10: Electricity Generation (Billion kWh) and Emissions (MMT CO_2 Eq.)



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 3-11).

Figure 3-11: Electricity Generation Retail Sales by End-Use Sector (Billion kWh)



The electric power industry includes all power producers, consisting of both regulated utilities and non-utilities (e.g., independent power producers, qualifying co-generators, 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.[89]

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. In 2015, electricity sales to the residential end-use sector decreased by 0.2 percent and sales to the commercial end-use sector increased by 0.6 percent, respectively. The trend in the residential sector can largely be attributed to warmer, less energy-intensive winter conditions while the trend in the commercial sector can largely be attributed to a growing economy compared to 2014. Electricity sales to the industrial sector in 2015 decreased approximately 0.7 percent. Overall, in 2015, the amount of electricity generated (in kWh) and the amount of electricity consumed (in kWh) decreased approximately 0.4 percent and 0.1 percent, respectively, relative to the previous year, while CO_2 emissions from the electric power sector decreased by 6.7 percent. The decrease in CO_2 emissions was a result of a significant decrease in the consumption of coal and increase in the consumption of natural gas for electricity generation by 13.9 percent and 18.7 percent, respectively, in 2015, and a decrease in the consumption of petroleum for electricity generation by 6.6 percent.

Industrial Sector

Industrial sector CO_2, CH_4, and N_2O, emissions accounted for 16, 16, and 6 percent of CO_2, CH_4, and N_2O, emissions from fossil fuel combustion, respectively. Carbon dioxide, CH_4, and N_2O emissions resulted from the direct consumption of fossil fuels for steam and process heat production.

The industrial end-use sector, per the underlying energy consumption data from EIA, includes activities such as manufacturing, construction, mining, and agriculture. The largest of these activities in terms of energy consumption is manufacturing, of which six industries—Petroleum Refineries, Chemicals, Paper, Primary Metals, Food, and Nonmetallic Mineral Products—represent the vast majority of the energy use (EIA 2017a 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.[90] 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 2014 to 2015, total industrial production and manufacturing output increased by 1.9 percent (FRB 2016). Over this period, output increased across production indices for Food, Petroleum Refineries, Chemicals, and Nonmetallic Mineral Products, and decreased slightly for Primary Metals and Paper (see Figure 3-12). Through EPA's Greenhouse Gas Reporting Program (GHGRP), specific industrial sector trends can be discerned from the overall total EIA industrial fuel consumption data used for these calculations.

For example, from 2014 to 2015, the underlying EIA data showed decreased consumption of coal, and relatively flat use of natural gas in the industrial sector. The GHGRP data highlights that several industries contributed to these trends, including chemical manufacturing; pulp, paper and print; and food processing, beverages and tobacco.[91]

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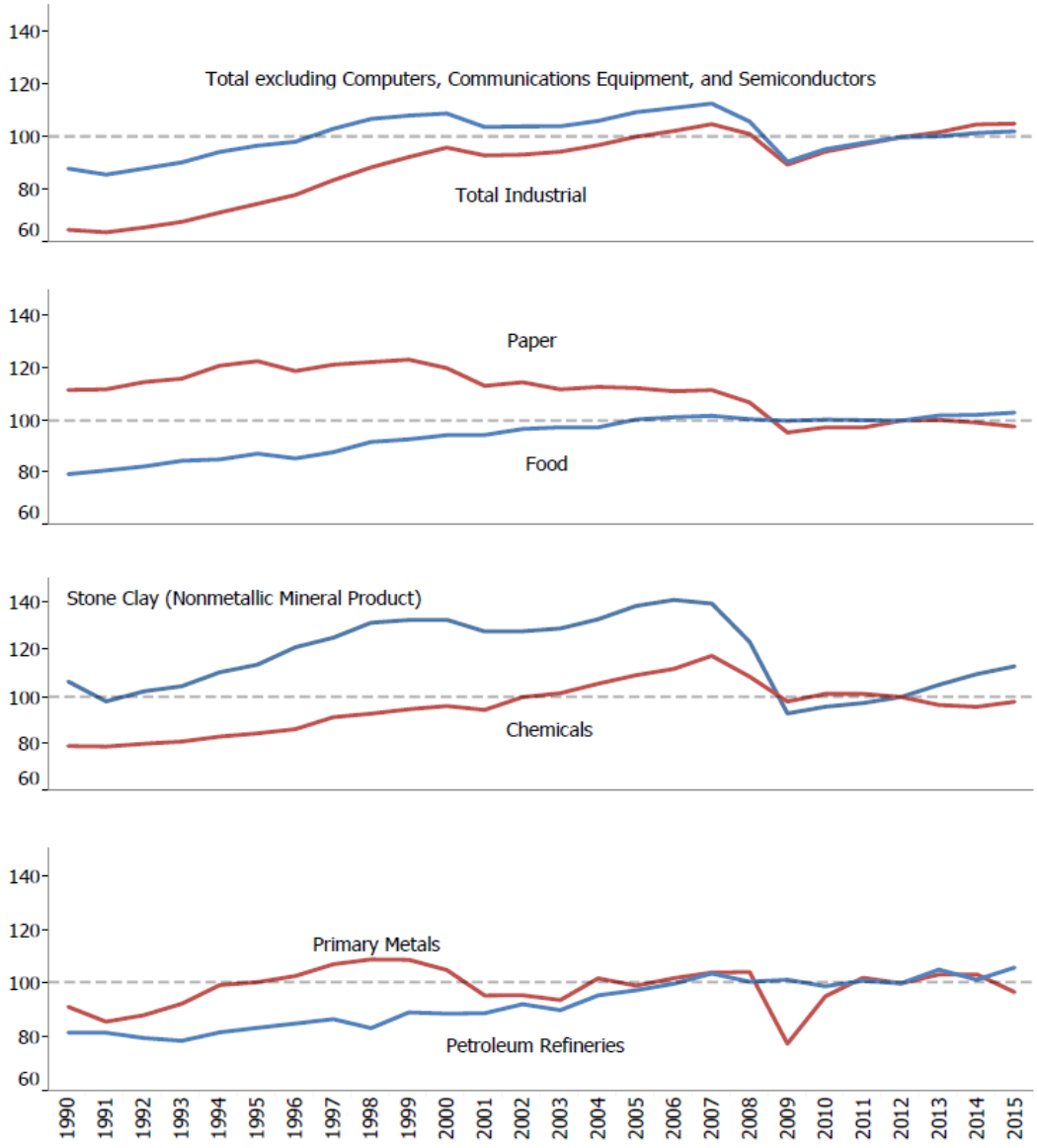
[89] Utilities primarily generate power for the U.S. electric grid for sale to retail customers. Nonutilities produce electricity for their own use, to sell to large consumers, or to sell on the wholesale electricity market (e.g., to utilities for distribution and resale to customers).

[90] 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.

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

Figure 3-12: Industrial Production Indices (Index 2007=100)



Despite the growth in industrial output (64 percent) and the overall U.S. economy (83 percent) from 1990 to 2015, CO_2 emissions from fossil fuel combustion in the industrial sector decreased by 4.4 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 2015, CO_2, CH_4, and N_2O emissions from fossil fuel combustion and electricity use within the industrial end-use sector totaled 1,364.6 MMT CO_2 Eq., a 3.2 percent decrease from 2014 emissions.

Residential and Commercial Sectors

Residential and commercial sector CO_2 emissions accounted for 6 and 5 percent of CO_2 emissions from fossil fuel combustion, CH_4 emissions accounted for 43 and 13 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 2015, CO_2, CH_4, and N_2O emissions from fossil fuel combustion and electricity use within the residential and commercial end-use sectors were 1,015.7 MMT CO_2 Eq. and 917.9 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 decreased by 7.1 and 2.7 percent from 2014 to 2015, respectively.

Emissions from the residential and commercial end-use 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 2015, combustion emissions from natural gas consumption represented 79 and 71 percent of the direct fossil fuel CO_2 emissions from the residential and commercial sectors, respectively. Natural gas combustion CO_2 emissions from the residential and commercial sectors in 2015 decreased by 9.0 percent and 7.4 percent from 2014 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 of 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. Table 3-7 presents direct CO_2, CH_4, and N_2O emissions from all transportation sources (i.e., excluding emissions allocated to electricity consumption in the transportation end-use sector).

The transportation end-use sector and other mobile combustion accounted for 1,757.3 MMT CO_2 Eq. in 2015, which represented 34 percent of CO_2 emissions, 22 percent of CH_4 emissions, and 40 percent of N_2O emissions from fossil fuel combustion, respectively.[92] Fuel purchased in the United States for international aircraft and marine travel accounted for an additional 111.8 MMT CO_2 Eq. in 2015; these emissions are recorded as international bunkers and are not included in U.S. totals according to UNFCCC reporting protocols.

Transportation End-Use Sector

From 1990 to 2015, transportation emissions from fossil fuel combustion rose by 14 percent due, in large part, to increased demand for travel.[93] The number of vehicle miles traveled (VMT) by light-duty motor vehicles (passenger cars and light-duty trucks) increased 40 percent from 1990 to 2015,[94] as a result of a confluence of factors including population growth, economic growth, urban sprawl, and periods of low fuel prices.

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[92] Note that these totals include CO_2, 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.

[93] In 2016, FHWA changed its methods for estimating the share of gasoline used in on-road and non-road applications, which created a time-series inconsistency between 2015 and previous years in this Inventory. The method changes resulted in a decrease in the estimated motor gasoline consumption for the transportation sector and a subsequent increase in the commercial and industrial sectors of this Inventory for 2015. The method updates are discussed further in the Planned Improvements section below under CO_2 from Fossil Fuel Combustion.

[94] VMT estimates are based on data from FHWA Highway Statistics Table VM-1 (FHWA 1996 through 2016). In 2011, FHWA changed its methods for estimating VMT by vehicle class, which led to a shift in VMT and emissions among on-road vehicle

From 2014 to 2015, CO_2 emissions from the transportation end-use sector decreased by 0.4 percent, though this downward trend is likely due to a methodology update in 2015 that decreased on-road motor gasoline consumption estimates relative to the previous methodology.[95,96] These methodological updates, however, did not impact overall gasoline consumption (discussed in the upfront section of this Chapter), which increased from 2014 to 2015 and remains largely influenced by transportation sector trends (e.g., VMT growth) as the majority of motor gasoline in 2015 was consumed in the transportation sector (95 percent). From 2014 to 2015, there were increases in on-road distillate fuel oil use in medium- and heavy-duty trucks, jet fuel use in general aviation and commercial aircraft, and fuel use in ships and non-recreational boats.

Commercial aircraft emissions increased slightly between 2014 and 2015, but have decreased 15 percent since 2007 (FAA 2017).[97] 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. Annex 3.2 presents the total emissions from all transportation and mobile sources, including CO_2, N_2O, CH_4, and HFCs.

Transportation Fossil Fuel Combustion CO_2 Emissions

Domestic transportation CO_2 emissions increased by 16 percent (243.3 MMT CO_2) between 1990 and 2015, an annualized increase of 0.6 percent.[98] Among domestic transportation sources, in 2015, light-duty vehicles (including passenger cars and light-duty trucks) represented 59 percent of CO_2 emissions from fossil fuel combustion, medium- and heavy-duty trucks and buses 25 percent, commercial aircraft 7 percent, and other sources 9 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. Carbon dioxide 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.[99] Ethanol consumption from the transportation sector has increased from 0.7 billion gallons in 1990 to 13.1 billion gallons in 2015, while biodiesel consumption has increased from 0.01 billion gallons in 2001 to 1.5 billion gallons in 2015. For further information, see Section 3.10 on biofuel consumption at the end of this chapter and Table A-95 in Annex 3.2.

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classes in the 2007 to 2015 time period. In absence of these method changes, light-duty VMT growth between 1990 and 2015 would likely have been even higher.

95 In 2016, FHWA changed its methods for estimating the share of gasoline used in on-road and non-road applications, which created a time-series inconsistency between 2015 and previous years in this Inventory. The method changes resulted in a decrease in the estimated motor gasoline consumption for the transportation sector and a subsequent increase in the commercial and industrial sectors of this Inventory for 2015. The method updates are discussed further in the Planned Improvements section below under CO_2 from Fossil Fuel Combustion.

96 Note that this value does not include lubricants.

97 Commercial aircraft, as modeled in FAA's AEDT (FAA 2017), consists of passenger aircraft, cargo, and other chartered flights.

98 In 2016, FHWA changed its methods for estimating the share of gasoline used in on-road and non-road applications, which created a time-series inconsistency between 2015 and previous years in this Inventory. The method changes resulted in a decrease in the estimated motor gasoline consumption for the transportation sector and a subsequent increase in the commercial and industrial sectors of this Inventory for 2015. The method updates are discussed further in the Planned Improvements section below under CO_2 from Fossil Fuel Combustion.

99 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 Standards website. See <https://www.epa.gov/renewable-fuel-standard-program>.

Carbon dioxide emissions from passenger cars and light-duty trucks totaled 1,033.7 MMT CO_2 in 2015, an increase of 9 percent (83.7 MMT CO_2) from 1990[100] due, in large part, to increased demand for travel as fleet-wide 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 2015). Carbon dioxide emissions from passenger cars and light-duty trucks peaked at 1,180.5 MMT CO_2 in 2004, and since then have declined about 12 percent.[101] The decline in new light-duty vehicle fuel economy between 1990 and 2004 (Figure 3-13) 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. Starting in 2005, average new vehicle fuel economy began to increase while light-duty VMT grew only modestly for much of the period. Light-duty VMT grew by less than one percent or declined each year between 2005 and 2013[102] and has since grown at a faster rate (1.2 percent from 2013 to 2014, and 2.6 percent from 2014 to 2015. Average new vehicle fuel economy has improved almost every year since 2005, and the truck share decreased to about 33 percent in 2009, and has since varied from year to year between 36 and 43 percent. Truck share is about 43 percent of new vehicles in model year 2015 (EPA 2016c).

Medium- and heavy-duty truck CO_2 emissions increased by 78 percent from 1990 to 2015. This increase was largely due to a substantial growth in medium- and heavy-duty truck VMT, which increased by 95 percent between 1990 and 2015.[103] Carbon dioxide from the domestic operation of commercial aircraft increased by 8 percent (9.1 MMT CO_2) from 1990 to 2015.[104] Across all categories of aviation, excluding international bunkers, CO_2 emissions decreased by 15 percent (28.2 MMT CO_2) between 1990 and 2015.[105] This includes a 58 percent (20.3 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 and in the CH_4 and N_2O from Mobile Combustion section. Annex 3.2 presents total emissions from all transportation and mobile sources, including CO_2, CH_4, N_2O, and HFCs.

[100] In 2016, FHWA changed its methods for estimating the share of gasoline used in on-road and non-road applications, which created a time-series inconsistency between 2015 and previous years in this Inventory. The method changes resulted in a decrease in the estimated motor gasoline consumption for the transportation sector and a subsequent increase in the commercial and industrial sectors of this Inventory for 2015. The method updates are discussed further in the Planned Improvements section below under CO_2 from Fossil Fuel Combustion.

[101] See previous footnote.

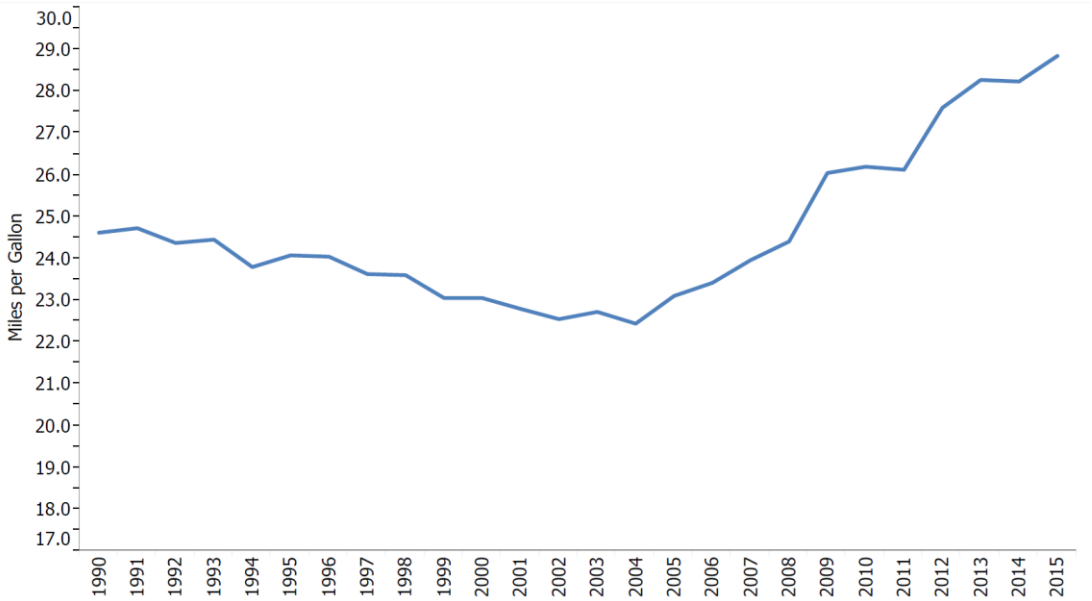
[102] VMT estimates are based on data from FHWA Highway Statistics Table VM-1 (FHWA 1996 through 2016). In 2007 and 2008 light-duty VMT decreased 3.0 percent and 2.3 percent, respectively. Note that the decline in light-duty VMT from 2006 to 2007 is due at least in part to a change in FHWA's methods for estimating VMT. In 2011, FHWA changed its methods for estimating VMT by vehicle class, which led to a shift in VMT and emissions among on-road vehicle classes in the 2007 to 2015 time period. In absence of these method changes, light-duty VMT growth between 2006 and 2007 would likely have been higher.

[103] While FHWA data shows consistent growth in medium- and heavy-duty truck VMT over the 1990 to 2015 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 2015 time period. During the time period prior to the method change (1990 to 2006), VMT for medium- and heavy-duty trucks increased by 51 percent.

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

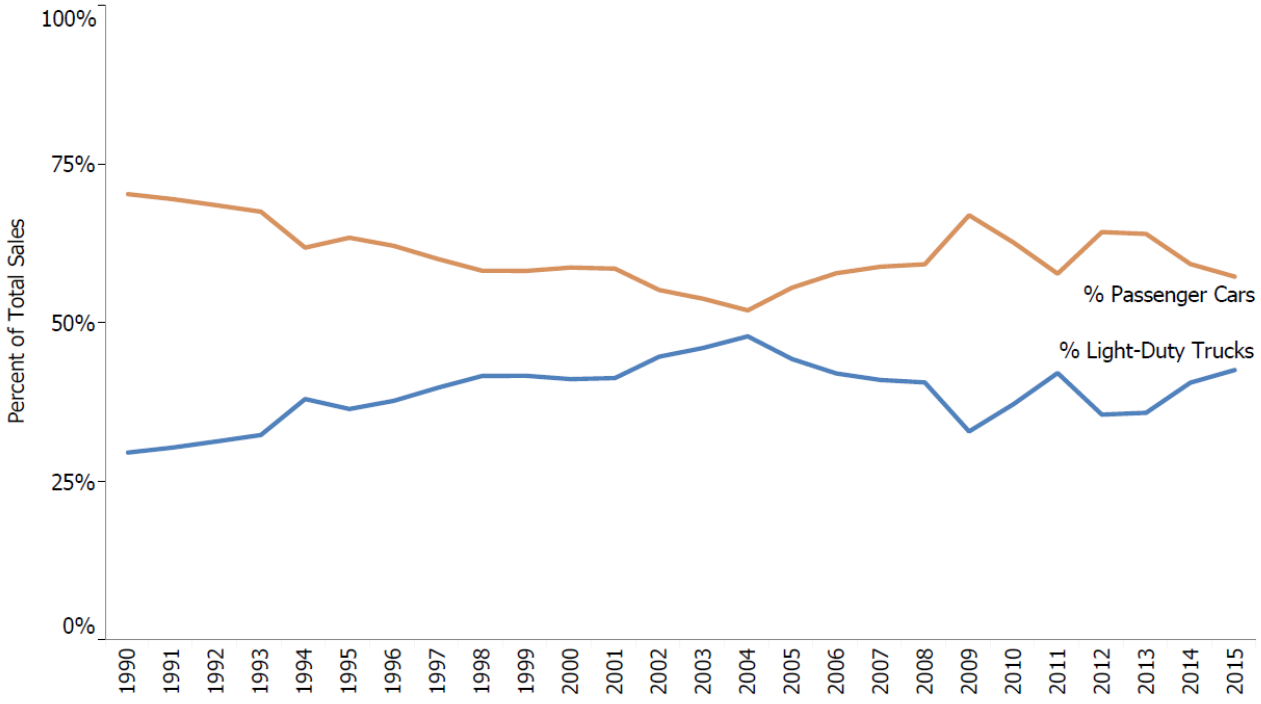
[105] Includes consumption of jet fuel and aviation gasoline. Does not include aircraft bunkers, which are not included in national emission totals, in line with IPCC methodological guidance and UNFCCC reporting obligations.

Figure 3-13: Sales-Weighted Fuel Economy of New Passenger Cars and Light-Duty Trucks, 1990–2015 (miles/gallon)



Source: EPA (2016c)

Figure 3-14: Sales of New Passenger Cars and Light-Duty Trucks, 1990–2015 (Percent)



Source: EPA (2016c)

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

Fuel/Vehicle Type	1990	2005	2011[a]	2012[a]	2013[a]	2014[a]	2015[a, b]
Gasoline[b]	**983.5**	**1,183.7**	**1,068.8**	**1,064.7**	**1,065.6**	**1,096.1**	**1,070.5**
Passenger Cars	621.4	655.9	732.8	731.4	731.4	749.5	731.3
Light-Duty Trucks	309.1	477.2	280.4	277.4	277.7	299.9	283.2
Medium- and Heavy-Duty Trucks[c]	38.7	34.8	38.9	38.7	39.5	40.8	39.3
Buses	0.3	0.4	0.7	0.8	0.8	0.9	0.9
Motorcycles	1.7	1.6	3.6	4.1	3.9	3.9	3.7
Recreational Boats[d]	12.2	13.9	12.4	12.3	12.3	1.1	12.2
Distillate Fuel Oil (Diesel)[b]	**262.9**	**457.5**	**430.0**	**427.5**	**433.9**	**447.7**	**460.7**
Passenger Cars	7.9	4.2	4.1	4.1	4.1	4.1	4.3
Light-Duty Trucks	11.5	25.8	13.0	12.9	12.9	13.9	13.9
Medium- and Heavy-Duty Trucks[c]	190.5	360.2	344.4	344.4	350.0	361.2	369.4
Buses	8.0	10.6	14.4	15.4	15.5	16.9	17.3
Rail	35.5	45.5	40.4	39.5	40.1	41.6	39.9
Recreational Boats	2.0	3.2	3.6	3.7	3.7	3.8	3.9
Ships and Non-Recreational Boats[e]	7.5	8.0	10.1	7.5	7.5	6.2	12.0
International Bunker Fuels[f]	*11.7*	*9.4*	*7.9*	*6.8*	*5.6*	*6.1*	*8.4*
Jet Fuel	**184.2**	**189.3**	**146.6**	**143.4**	**147.1**	**148.6**	**157.7**
Commercial Aircraft[g]	109.9	132.7	114.6	113.3	114.3	115.2	119.0
Military Aircraft	35.0	19.4	11.6	12.1	11.0	15.4	14.7
General Aviation Aircraft	39.4	37.3	20.4	18.0	21.8	18.0	24.0
International Bunker Fuels[f]	*38.0*	*60.1*	*64.8*	*64.5*	*65.7*	*69.4*	*71.8*
International Bunker Fuels from Commercial Aviation	*30.0*	*55.6*	*61.7*	*61.4*	*62.8*	*66.3*	*68.6*
Aviation Gasoline	**3.1**	**2.4**	**1.9**	**1.7**	**1.5**	**1.5**	**1.5**
General Aviation Aircraft	3.1	2.4	1.9	1.7	1.5	1.5	1.5
Residual Fuel Oil	**22.6**	**19.3**	**19.4**	**15.8**	**15.1**	**5.8**	**4.2**
Ships and Boats[e]	22.6	19.3	19.4	15.8	15.1	5.8	4.2
International Bunker Fuels[f]	*53.7*	*43.6*	*38.9*	*34.5*	*28.5*	*27.7*	*30.6*
Natural Gas[j]	**36.0**	**33.1**	**38.9**	**41.3**	**47.0**	**40.3**	**38.8**
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+
Medium- and Heavy-Duty Trucks	+	+	+	+	+	+	+
Buses	+	0.6	0.8	0.8	0.8	0.8	0.8
Pipeline[h]	36.0	32.4	38.1	40.5	46.2	39.4	38.0
LPG[j]	**1.4**	**1.7**	**2.1**	**2.3**	**2.7**	**2.9**	**3.0**
Passenger Cars	+	+	+	+	+	+	0.1
Light-Duty Trucks	0.2	0.3	0.4	0.2	0.3	0.6	0.9
Medium- and Heavy-Duty Trucks[c]	1.1	1.3	1.4	1.8	2.1	1.9	1.7
Buses	0.1	0.1	0.2	0.3	0.4	0.3	0.3
Electricity	**3.0**	**4.7**	**4.3**	**3.9**	**4.0**	**4.1**	**3.7**
Rail	3.0	4.7	4.3	3.9	4.0	4.1	3.7
Total[k]	**1,496.8**	**1,891.8**	**1,711.9**	**1,700.6**	**1,717.0**	**1,746.9**	**1,740.1**
Total (Including Bunkers)[f]	**1,600.3**	**2,004.9**	**1,823.6**	**1,806.4**	**1,816.8**	**1,8501.1**	**1,850.9**
Biofuels-Ethanol[i]	*4.1*	*22.4*	*71.5*	*71.5*	*73.4*	*74.9*	*75.9*
Biofuels-Biodiesel[i]	*0.0*	*0.9*	*8.3*	*8.5*	*13.5*	*13.3*	*14.1*

+ Does not exceed 0.05 MMT CO_2 Eq.

[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 1990 through 2010 Inventory and apply to the 2007 through 2015 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] Gasoline and diesel highway vehicle fuel consumption estimates are based on data from FHWA Highway Statistics Table MF-21, MF-27, and VM-1 (FHWA 1996 through 2016). In 2016, FHWA changed its methods for estimating the share of gasoline used in on-road and non-road applications, which created a time-series inconsistency between 2015 and previous years in this Inventory. The method changes resulted in a decrease in the estimated motor gasoline consumption for the transportation sector and a subsequent increase in the commercial and industrial sectors of this Inventory for 2015. The method updates are discussed further in the Planned Improvements section below under CO_2 from Fossil Fuel Combustion. Data from Table VM-1 is used to estimate the share of consumption between each on-road vehicle class. These fuel consumption estimates are combined with estimates of fuel shares by vehicle type from DOE's TEDB Annex Tables A.1 through A.6 (DOE 1993 through 2016). TEDB data for 2015 has not been published yet, therefore 2014 data is used as a proxy.

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

[d] In 2014, EPA incorporated the NONROAD2008 model into MOVES2014. The current Inventory uses the NONROAD component of MOVES2014a for years 1999 through 2015.

[e] Note that large year over year fluctuations in emission estimates partially reflect nature of data collection for these sources.

[f] 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.

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

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

[i] Ethanol and biodiesel 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 and biodiesel.

[j] Transportation sector natural gas and LPG consumption are based on data from EIA (2016). In previous Inventory years, data from DOE TEDB was used to estimate each vehicle class's share of the total natural gas and LPG consumption. Since TEDB does not include estimates for natural gas use by medium and heavy duty trucks or LPG use by passenger cars, EIA Alternative Fuel Vehicle Data (Browning 2017) is now used to determine each vehicle class's share of the total natural gas and LPG consumption. These changes were first incorporated in this year's Inventory and apply to the 1990 to 2015 time period.

[k] Includes emissions from rail electricity.

Notes: 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. Totals may not sum due to independent rounding.

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 and electric locomotives;[106] 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.). [107] Annex 3.2 includes a summary of all emissions from both

[106] 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.

[107] 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 Industrial 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 emission 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.

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.[108]

Mobile combustion was responsible for a small portion of national CH_4 emissions (0.3 percent) but was the fourth largest source of U.S. N_2O emissions (4.5 percent). From 1990 to 2015,[109] mobile source CH_4 emissions declined by 64 percent, to 2.0 MMT CO_2 Eq. (80 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 63 percent, to 15.1 MMT CO_2 Eq. (51 kt N_2O).[110] 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 71 percent decrease in mobile source N_2O emissions from 1997 to 2015 (Figure 3-15). Overall, CH_4 and N_2O emissions were predominantly from gasoline-fueled passenger cars and light-duty trucks.

Figure 3-15: Mobile Source CH_4 and N_2O Emissions (MMT CO_2 Eq.)

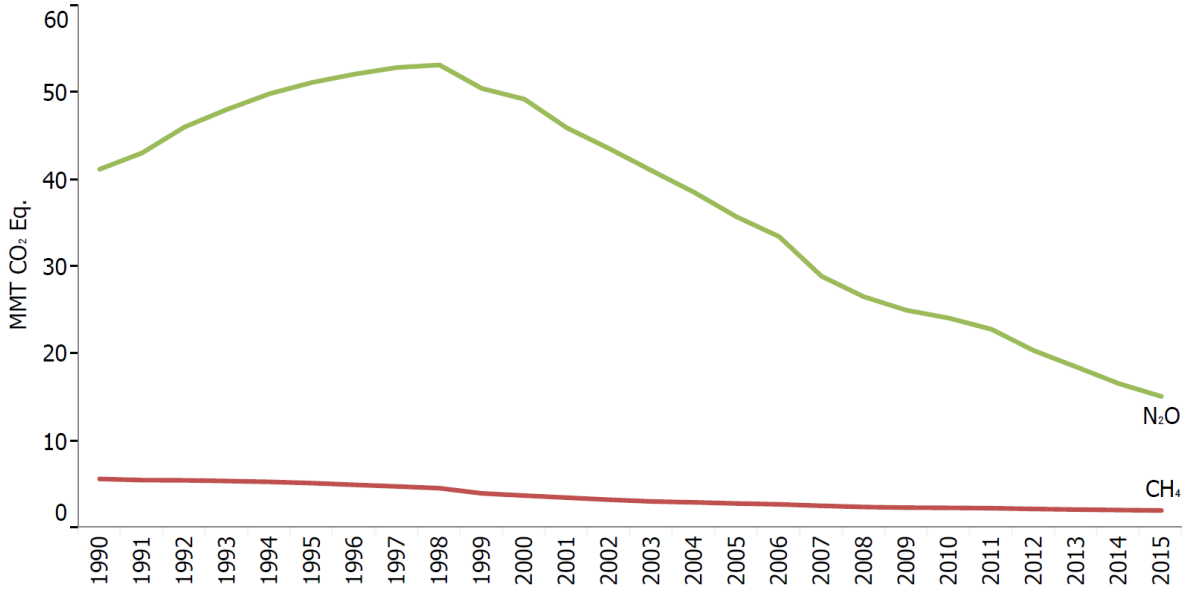


Table 3-13: CH_4 Emissions from Mobile Combustion (MMT CO_2 Eq.)

Fuel Type/Vehicle Type[a]	1990	2005	2011	2012	2013	2014	2015
Gasoline On-Road[b]	**5.2**	**2.2**	**1.7**	**1.6**	**1.5**	**1.4**	**1.4**
Passenger Cars	3.2	1.2	1.2	1.1	1.1	1.0	1.0
Light-Duty Trucks	1.7	0.9	0.4	0.4	0.3	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	+	+	+	+	+	+	+

[108] See Annex 3.2 for a complete time series of emission estimates for 1990 through 2015.

[109] In 2016, FHWA changed its methods for estimating the share of gasoline used in on-road and non-road applications. These method changes created a time-series inconsistency in this Inventory between 2015 and previous years in CH_4 and N_2O estimates for agricultural, construction, commercial, and industrial non-road mobile sources. The method updates are discussed further in the Planned Improvements section of below under CH_4 and N_2O from Mobile Combustion.

[110] See above.

Medium- and Heavy-Duty Trucks and Buses	+	+	+	+	+	+	+
Alternative Fuel On-Road	**+**	**+**	**+**	**+**	**+**	**+**	**+**
Non-Road[c]	**0.4**	**0.5**	**0.5**	**0.6**	**0.6**	**0.6**	**0.5**
Ships and Boats	+	+	+	+	+	+	+
Rail[d]	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Aircraft	0.1	0.1	+	+	+	+	+
Agricultural Equipment[e]	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Construction/Mining Equipment[f]	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Other[g]	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**5.6**	**2.8**	**2.3**	**2.2**	**2.1**	**2.1**	**2.0**

+ Does not exceed 0.05 MMT CO_2 Eq.

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

[b] Gasoline and diesel highway vehicle mileage estimates are based on data from FHWA Highway Statistics Table VM-1 (FHWA 1996 through 2016). These mileage estimates are combined with estimates of fuel shares by vehicle type from DOE's TEDB Annex Tables A.1 through A.6 (DOE 1993 through 2016). TEDB data for 2015 has not been published yet, therefore 2014 data is used as a proxy.

[c] In 2016, FHWA changed its methods for estimating the share of gasoline used in on-road and non-road applications. These method changes created a time-series inconsistency in this Inventory between 2015 and previous years in CH_4 and N_2O estimates for agricultural, construction, commercial, and industrial non-road mobile sources. The method updates are discussed further in the *Planned Improvements* section below under *CH_4 and N_2O from Mobile Combustion*.

[d] Rail emissions do not include emissions from electric powered locomotives. Class II and Class III diesel consumption data for 2014 and 2015 are not available yet, therefore 2013 data is used as a proxy.

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

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

[g] "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.

Notes: 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 through 2010 Inventory and apply to the 2007 through 2015 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. Totals may not sum due to independent rounding.

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

Fuel Type/Vehicle Type[a]	1990	2005	2011	2012	2013	2014	2015
Gasoline On-Road[b]	**37.5**	**31.3**	**18.4**	**16.1**	**14.1**	**12.3**	**10.8**
Passenger Cars	24.1	15.7	12.1	10.5	9.2	7.8	6.9
Light-Duty Trucks	12.8	14.7	5.6	4.9	4.3	4.0	3.4
Medium- and Heavy-Duty Trucks and Buses	0.5	0.9	0.7	0.7	0.6	0.5	0.5
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**	**0.1**	**0.1**
Non-Road[c]	**3.5**	**4.1**	**4.0**	**3.9**	**4.0**	**3.8**	**3.9**
Ships and Boats	0.6	0.6	0.8	0.7	0.7	0.5	0.6
Rail[d]	0.3	0.3	0.3	0.3	0.3	0.4	0.3
Aircraft	1.7	1.8	1.4	1.3	1.4	1.4	1.5
Agricultural Equipment[e]	0.2	0.4	0.4	0.4	0.4	0.4	0.4

Construction/Mining Equipment[f]	0.3	0.5	0.6	0.6	0.6	0.6	0.6
Other[g]	0.4	0.6	0.6	0.6	0.6	0.6	0.6
Total	**41.2**	**35.7**	**22.8**	**20.4**	**18.5**	**16.6**	**15.1**

+ Does not exceed 0.05 MMT CO_2 Eq.

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

[b] Gasoline and diesel highway vehicle mileage estimates are based on data from FHWA Highway Statistics Table VM-1 (FHWA 1996 through 2016). These mileage estimates are combined with estimates of fuel shares by vehicle type from DOE's TEDB Annex Tables A.1 through A.6 (DOE 1993 through 2016). TEDB data for 2015 has not been published yet, therefore 2014 data is used as a proxy.

[c] In 2016, FHWA changed its methods for estimating the share of gasoline used in on-road and non-road applications. These method changes created a time-series inconsistency in this Inventory between 2015 and previous years in CH_4 and N_2O estimates for agricultural, construction, commercial, and industrial non-road mobile sources. The method updates are discussed further in the Planned Improvements section below under CH_4 and N_2O from Mobile Combustion.

[d] Rail emissions do not include emissions from electric powered locomotives. Class II and Class III diesel consumption data for 2014 and 2015 are not available yet, therefore 2013 data is used as a proxy.

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

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

[g] "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.

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 through 2010 Inventory and apply to the 2007 through 2015 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. Totals may not sum due to independent rounding.

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).[111] 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 (EIA 2017a). 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 2017b) and Jacobs (2010).[112]

   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

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

[112] 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 total emissions of 41.5 MMT CO_2 Eq. in 2015.

presented "top down"—that is, energy consumption for fuel types and categories are estimated from energy production data (accounting for imports, exports, stock changes, and losses). The resulting quantities are referred to as "apparent consumption." The data collected in the United States by EIA on an annual basis and used in this Inventory are predominantly from mid-stream or conversion energy consumers such as refiners and electric power generators. These annual surveys are supplemented with end-use energy consumption surveys, such as the Manufacturing Energy Consumption Survey, that are conducted on a 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.[113]

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).[114]

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 2016), Coffeyville (2012), U.S. Census Bureau (2001 through 2011), EIA (2017a, 2016a, 2016b), USAA (2008 through 2016), USGS (1991 through 2015a), (USGS 2016a), USGS (2014 through 2016a), USGS (2014 through 2016b), USGS (1995 through 2013), USGS (1995, 1998, 2000, 2001), USGS (2016b), USGS (20016c), USGS (2015a), USGS (1991 through 2013), USGS (2016d), USGS (2015b), USGS (2014), USGS (1996 through 2013), USGS (1991 through 2015b), USGS (2015 and 2016), USGS (1991 through 2015c).[115]

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.[116] 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.[117] 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, the associated fossil fuel burned to create the exported CO_2 is subtracted from fossil fuel consumption statistics. The associated fossil fuel is the total fossil fuel burned at the plant with the CO_2 capture system multiplied by the fraction of the plant's total site-generated CO_2 that is recovered by the capture system. To make these adjustments, additional data for ethanol and biodiesel were collected from EIA (2017a), data for synthetic natural gas were collected from EIA (2016a), 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

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[113] 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.

[114] 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.

[115] 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.

[116] Energy statistics from EIA (2017a) are already adjusted downward to account for ethanol added to motor gasoline, biodiesel added to diesel fuel, and biogas in natural gas.

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

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 2016), Benson (2002 through 2004), DOE (1993 through 2016), EIA (2007), EIA (1991 through 2016), EPA (2016d), and FHWA (1996 through 2016).[118]

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 Section 3.2 – Carbon Emitted and Stored in Products from Non-Energy Uses of Fossil Fuels. 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 (2017a).

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).[119] 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 2016) supplied data on military jet fuel and marine fuel use. Commercial jet fuel use was obtained from FAA (2017); residual and distillate fuel use for civilian marine bunkers was obtained from DOC (1991 through 2016) for 1990 through 2001 and 2007 through 2014, 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 in Section 3.9 – International Bunker Fuels.

7. *Determine the total C content of fuels consumed.* Total C was estimated by multiplying the amount of fuel consumed by the amount of C in each fuel. This total C estimate defines the maximum amount of C that could potentially be released to the atmosphere if all of the C in each fuel was converted to CO_2. The C content coefficients used by the United States were obtained from EIA's *Emissions of Greenhouse Gases in the United States 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 fuel types other than jet fuel, fuel consumption data by vehicle type and transportation mode were used to

[118] Bottom-up gasoline and diesel highway vehicle fuel consumption estimates are based on data from FHWA Highway Statistics Table MF-21, MF-27, and VM-1 (FHWA 1996 through 2016). In 2016, FHWA changed its methods for estimating the share of gasoline used in on-road and non-road applications, which created a time-series inconsistency between 2015 and previous years in this Inventory. The method changes resulted in a decrease in the estimated motor gasoline consumption for the transportation sector and a subsequent increase in the commercial and industrial sectors of this Inventory for 2015. The method updates are discussed further in the Planned Improvements section below.

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

allocate emissions by fuel type calculated for the transportation end-use sector. Heat contents and densities were obtained from EIA (2017a) and USAF (1998).[120]

- For on-road vehicles, annual estimates of combined motor gasoline and diesel fuel consumption by vehicle category were obtained from FHWA (1996 through 2016); for each vehicle category, the percent gasoline, diesel, and other (e.g., CNG, LPG) fuel consumption are estimated using data from DOE (1993 through 2016). [121,122]
- For non-road vehicles, activity data were obtained from AAR (2008 through 2016), APTA (2007 through 2016), APTA (2006), BEA (2016), Benson (2002 through 2004), DOE (1993 through 2016), DLA Energy (2016), DOC (1991 through 2016), DOT (1991 through 2016), EIA (2009a), EIA (2017a), EIA (2013), EIA (1991 through 2016), EPA (2016d),[123] 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 IPCC (2006) (see Annex 3.3). Carbon dioxide 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 GHGRP 2010 through 2015 reporting years, facility-level fossil fuel combustion emissions reported through EPA's GHGRP were categorized and distributed to specific industry types by utilizing facility-reported NAICS codes (as published by the U.S. Census Bureau). 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

[120] 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, respectively.

[121] Data from FHWA's Table VM-1 is used to estimate the share of fuel consumption between each on-road vehicle class. Since VM-1 data for 2015 has not been published yet, fuel consumption shares from 2014 are used as a proxy for the current Inventory. These fuel consumption estimates are combined with estimates of fuel shares by vehicle type from DOE's TEDB Annex Tables A.1 through A.6 (DOE 1993 through 2016). TEDB data for 2015 has not been published yet, therefore 2014 data is used as a proxy. 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 through 2010 Inventory and apply to the 2007 through 2015 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.

[122] Transportation sector natural gas and LPG consumption are based on data from EIA (2016). In previous Inventory years, data from DOE TEDB was used to estimate each vehicle class's share of the total natural gas and LPG consumption. Since TEDB does not include estimates for natural gas use by medium and heavy duty trucks or LPG use by passenger cars, EIA Alternative Fuel Vehicle Data (Browning 2017) is now used to determine each vehicle class's share of the total natural gas and LPG consumption. These changes were first incorporated in the current Inventory and apply to the 1990 to 2015 time period.

[123] In 2014, EPA incorporated the NONROAD2008 model into MOVES2014. The current Inventory uses the NONROAD component of MOVES2014a for years 1999 through 2015.

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.[124]

As with previous Inventory reports, the current 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 CRF tables that are submitted to the UNFCCC along with this report.[125] The efforts in reconciling fuels focus 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 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. The current analysis includes the full time series presented in the CRF tables. Analyses were conducted linking GHGRP facility-level reporting with the information published by EIA in its MECS data in order to disaggregate the full 1990 through 2015 time series in the CRF tables. 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. This includes incorporating the latest MECS data as it becomes available.

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.[126] 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 the purposes of following reporting guidelines and maintaining the focus of this section, renewable energy and nuclear electricity and consumption are not included in the totals shown in Table 3-15 in order to focus attention on fossil fuel combustion as detailed in this chapter. For example, the C intensity for the residential sector does not include the energy from or emissions related to the consumption of electricity for lighting. Looking only at this direct consumption of fossil fuels, the residential sector exhibited the lowest C intensity, which is related to the large percentage of its energy derived from natural gas for heating. The C intensity of the commercial sector has predominantly declined since 1990 as commercial businesses shift away from petroleum to natural gas. The industrial sector was more dependent on petroleum and coal than either the residential or commercial sectors, and thus had higher C intensities over this period. The C intensity of the transportation sector was closely related to the C content of petroleum products (e.g., motor gasoline and jet fuel, both around 70 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.

[124] 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/public/tb/TFI_Technical_Bulletin_1.pdf>.

[125] See <http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html>.

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

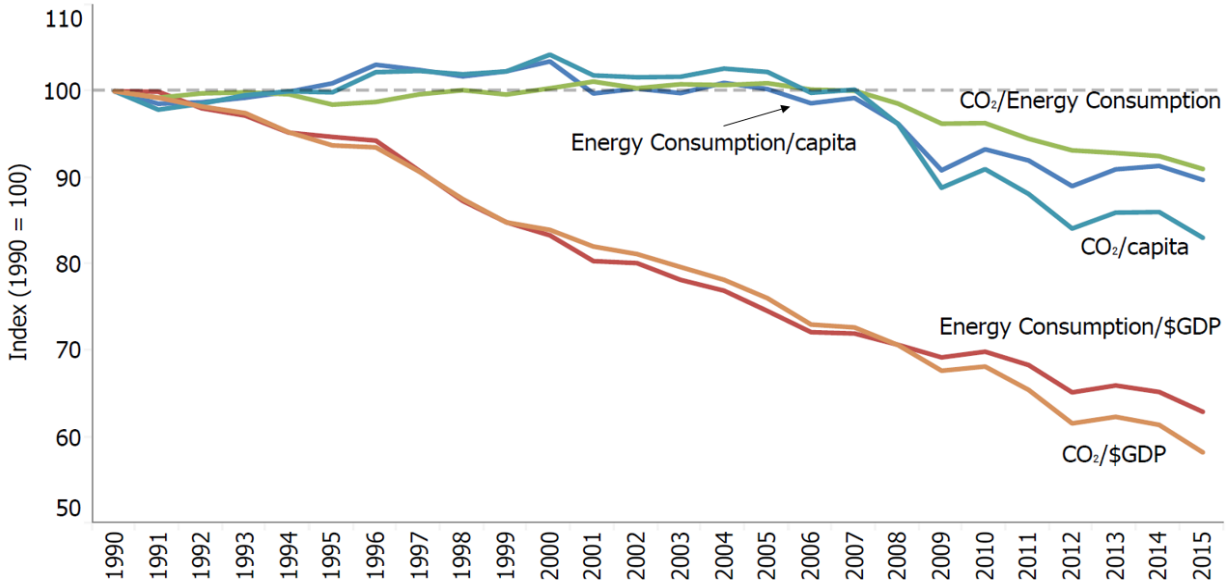
Table 3-15: Carbon Intensity from Direct Fossil Fuel Combustion by Sector (MMT CO_2 Eq./QBtu)

Sector	1990	2005	2011	2012	2013	2014	2015
Residential[a]	57.4	56.6	55.7	55.5	55.3	55.4	55.6
Commercial[a]	59.1	57.5	56.5	56.1	55.8	55.5	57.3
Industrial[a]	64.3	64.3	62.4	62.0	61.8	61.4	61.2
Transportation[a]	71.1	71.4	71.5	71.5	71.4	71.5	71.5
Electricity Generation[b]	87.3	85.8	82.9	79.9	81.3	81.2	78.1
U.S. Territories[c]	73.0	73.5	72.9	72.2	71.9	72.3	72.3
All Sectors[c]	**73.0**	**73.5**	**72.0**	**70.9**	**70.9**	**70.8**	**69.7**

[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.

For the time period of 1990 through about 2008, the C intensity of U.S. energy consumption was fairly constant, as the proportion of fossil fuels used by the individual sectors did not change significantly over that time. Starting in 2008 the C intensity has decreased, reflecting the shift from coal to natural gas in the electricity sector during that time period. Per capita energy consumption fluctuated little from 1990 to 2007, but in 2015 was approximately 10.2 percent below levels in 1990 (see Figure 3-16). To differentiate these estimates from those of Table 3-15, the C intensity trend shown in Figure 3-16 and described below includes nuclear and renewable energy EIA data to provide a comprehensive economy-wide picture of energy consumption. 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 2017).

Figure 3-16: 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 (2017a), EPA (2010), 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 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 (Section 3.2). 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 Section 3.9 – International Bunker Fuels). 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.[127] Triangular distributions were assigned for

[127] 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.

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.[128]

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).[129] 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 2015 were estimated to be between 4,944.0 and 5,286.9 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 2 percent below to 5 percent above the 2015 emission estimate of 5,049.8 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	2015 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]	**1,423.3**	**1,374.3**	**1,555.7**	**-3%**	**9%**
Residential	NE	NE	NE	NE	NE
Commercial	2.9	2.8	3.4	-5%	15%
Industrial	65.9	62.7	76.3	-5%	16%
Transportation	NE	NE	NE	NE	NE
Electricity Generation	1,350.5	1,298.2	1,479.1	-4%	10%
U.S. Territories	4.0	3.5	4.8	-12%	19%
Natural Gas[b]	**1,463.6**	**1,447.1**	**1,531.1**	**-1%**	**5%**
Residential	252.8	245.7	270.5	-3%	7%
Commercial	175.4	170.5	187.7	-3%	7%
Industrial	467.5	453.3	500.8	-3%	7%
Transportation	38.8	37.7	41.5	-3%	7%
Electricity Generation	526.1	510.9	553.0	-3%	5%
U.S. Territories	3.0	2.6	3.5	-12%	17%
Petroleum[b]	**2,162.5**	**2,032.6**	**2,289.5**	**-6%**	**6%**
Residential	66.8	63.1	70.4	-6%	5%
Commercial	67.9	64.0	71.5	-6%	5%
Industrial	272.2	219.4	321.0	-19%	18%
Transportation	1,697.6	1,587.0	1,808.2	-7%	7%
Electric Utilities	23.7	22.5	25.6	-5%	8%
U.S. Territories	34.3	31.8	38.1	-7%	11%
Total (excluding Geothermal)[b]	**5,049.4**	**4,943.6**	**5,286.5**	**-2%**	**5%**
Geothermal	0.4	NE	NE	NE	NE
Total (including Geothermal)[b,c]	**5,049.8**	**4,944.0**	**5,286.9**	**-2%**	**5%**

NE (Not Estimated)

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

[128] 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.

[129] 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.

[b] The low and high estimates for total emissions were calculated separately through simulations and, hence, the low and high emission estimates for the sub-source categories do not sum to total emissions.
[c] Geothermal emissions added for reporting purposes, but an uncertainty analysis was not performed for CO_2 emissions from geothermal production.

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990 through 2015 with one recent notable exception related to estimating the share of motor gasoline used in various sectors, which is discussed in the Planned Improvements section below. 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 general (Tier 1) analysis, as well as portions of a category-specific (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 2017a) updated energy consumption statistics across the time series relative to the previous Inventory. EIA revised 2014 natural gas consumption in all end-use sectors, 2011 through 2014 Liquefied Petroleum Gas (LPG) consumption in all end-use sectors, 2014 coal and natural gas consumption in the electric power sector, 2014 coal consumption in the commercial sector, and 2013 distillate fuel consumption in the industrial and transportation sectors. In 2016, EIA revised 2014 heat contents for coal, coal coke, and natural gas. The Federal Highway Administration (FHWA) updated 2014 motor gasoline consumption in the transportation sector, which also resulted in revisions to the commercial and industrial sector gasoline consumption and emissions for 2014. This change resulted in 2014 CO_2 emissions from fossil fuel combustion for the transportation sector increasing by 0.3 percent and decreasing by roughly 1 percent for the industrial and commercial sectors.

Energy consumption data for U.S. Territories was revised throughout the time series for petroleum, and in 2013 and 2014 for coal and natural gas (EIA 2017b).

Overall, these changes resulted in an average annual decrease of 0.4 MMT CO_2 Eq. (less than 0.1 percent) in CO_2 emissions from fossil fuel combustion for the period 1990 through 2014, relative to the previous Inventory.

Planned Improvements

To reduce uncertainty of CO_2 from fossil fuel combustion estimates for U.S. Territories, efforts will continue 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 total industrial sector fossil fuel combustion emissions by 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.[130] In line with UNFCCC reporting guidelines, fuel combustion emissions are included in this

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

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. For example, efforts will be taken to incorporate updated industrial fuel consumption data from EIA's Manufacturing Energy Consumption Survey (MECS), with updated data for 2014. Additional work will look at CO_2 emissions from biomass to ensure they 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.[131]

An ongoing 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 will continue to be investigated.

EPA received a comment from FHWA that the trend of decreasing electricity use in the transportation sector does not match up with increased sales of electric and plug-in hybrid vehicles. Electricity data is allocated between economic sectors based on electricity sales data provided by the industry through EIA reports. The data for electricity used in transportation only includes electricity used for railroads and railways. Electricity used to charge electric vehicles would fall under other sectors like residential and commercial use associated with home and public charging stations. As a planned improvement we will look into the possibility of breaking out electricity used to charge electric vehicles and report that electricity use under the transportation sector.

Lastly, an additional planned improvement is to evaluate and potentially update the methodology for allocating motor gasoline consumption across sectors to improve accuracy and create a more consistent time series. Sectoral motor gasoline CO_2 estimates in this Inventory are based on the annual publications of FHWA Highway Statistics Tables MF-21, MF-24, and VM-1 as well as data from EIA as discussed in the Methodology section above. In 2016, FHWA changed its methods for estimating the share of gasoline used in on-road and non-road applications.[132] While these method changes did not impact overall gasoline consumption CO_2 estimates in this Inventory (see discussion of overall gasoline trends in the upfront section of this Chapter), they did create a time-series inconsistency between 2015 and previous years in the allocation of gasoline among transportation, industrial, and commercial applications. The method changes resulted in a decrease in the estimated motor gasoline consumption for the transportation sector and a subsequent increase in the commercial and industrial sectors of this Inventory for 2015. Among other updates, FHWA included lawn and garden equipment as well as off-road recreational equipment in its estimates of non-road gasoline consumption for the first time; these non-road CO_2 sources are included in the industrial and commercial sectors in this Inventory for 2015. While the effects of FHWA's method changes are still being researched and cannot currently be isolated them from underlying trends, it is estimated estimate that, in absence of the changes, CO_2 emissions from fossil fuel combustion in transportation would have likely increased by roughly two percent from 2014 to 2015, instead of the modest decline shown in the time series in this Inventory; industrial CO_2 from fossil fuel combustion would have likely decreased by roughly two percent instead of modestly decreasing; and commercial CO_2 from fossil fuel combustion would have likely decreased by roughly four percent instead of increasing by eight percent. For 1990 through 2015 trends, it is estimated that, in absence of the changes, CO_2 emissions from fossil fuel combustion in transportation would have likely increased by roughly 19 percent, instead of 16 percent shown in the time series in this Inventory; industrial CO_2 from fossil fuel combustion would have likely decreased by roughly 6 percent instead of 4 percent; and commercial CO_2 from fossil fuel combustion would have likely increased by a few percent instead of 13 percent. EPA received a comment on

[131] See <http://www.ipcc-nggip.iges.or.jp/public/tb/TFI_Technical_Bulletin_1.pdf>.

[132] The previous and new FHWA methodologies for estimating non-road gasoline consumption are described in *Off-Highway and Public-Use Gasoline Consumption Estimation Models Used in the Federal Highway Administration*, Publication Number FHWA-PL-17-012. <https://www.fhwa.dot.gov/policyinformation/pubs/pl17012.pdf>

the draft version of this Inventory suggesting that the FHWA method updates be retrospectively applied for 2014 and earlier years. EPA plans to conduct further research to better understand FHWA's method updates and to consult EIA and FHWA regarding potential improvements to the method for gasoline sectoral allocation across the time series.

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). 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 2017a). Fuel consumption data for coal, natural gas, and fuel oil for the United States were also obtained from EIA's Monthly Energy Review (EIA 2017a). 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 2017b) and Jacobs (2010).[133] Fuel consumption for the industrial sector was adjusted to subtract out construction and agricultural use, which is reported under mobile sources.[134] Construction and agricultural fuel use was obtained from EPA (2016c) and FHWA (1996 through 2016). 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 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 2016a). This combustion technology- and fuel-use data was available by facility from 1996 to 2015. The Tier 2 emission factors used were taken from IPCC (2006), which in turn are based on emission factors published by EPA.

Since there was a difference between the EPA (2016a) and EIA (2017a) total energy consumption estimates, the remaining energy consumption from EIA (2016a) was apportioned to each combustion technology type and fuel combination using a ratio of energy consumption by technology type from 1996 to 2015.

Energy consumption estimates were not available from 1990 to 1995 in the EPA (2016a) dataset, and as a result, consumption was calculated using total electric power consumption from EIA (2017a) and the ratio of combustion technology and fuel types from EPA (2016a). 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.

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[133] 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.

[134] 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.

Lastly, there were significant differences between wood biomass consumption in the electric power sector between the EPA (2016a) and EIA (2017a) datasets. The higher wood biomass consumption from EIA (2017a) 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 (2017a).

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.[135] For these variables, the uncertainty ranges were assigned to the input variables based on the data reported in SAIC/EIA (2001).[136] 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 2015 (including biomass) were estimated to be between 4.5 and 16.5 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 36 percent below to 136 percent above the 2015 emission estimate of 7.0 MMT CO_2 Eq.[137] Stationary combustion N_2O emissions in 2015 (including biomass) were estimated to be between 18.2 and 34.7 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 22 percent below to 50 percent above the 2015 emission estimate of 23.1 MMT CO_2 Eq.

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

[136] 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.

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

Table 3-17: 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	2015 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	7.0	4.5	16.5	-36%	+136%
Stationary Combustion	N_2O	23.1	18.2	34.7	-22%	+50%

[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 2015 as discussed below. Details on the emission trends through time are described in more detail in the Methodology section, above.

For more information on the general QA/QC process applied to this source category, consistent with Volume 1, Chapter 6 of the *2006 IPCC Guidelines*, see QA/QC and Verification Procedures section in the introduction of the IPPU Chapter.

QA/QC and Verification

A source-specific QA/QC plan for stationary combustion was developed and implemented. This effort included a general (Tier 1) analysis, as well as portions of a category-specific (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

Methane and N_2O emissions from stationary sources (excluding CO_2) across the entire time series were revised due revised data from EIA (2017a), EIA (2017b), and EPA (2016a) relative to the previous Inventory. The historical data changes resulted in an average annual increase of less than 0.1 MMT CO_2 Eq. (less than 0.1 percent) in CH_4 emissions, and an average annual decrease of less than 0.1 MMT CO_2 Eq. (less than 0.1 percent) in N_2O emissions from stationary combustion for the period 1990 through 2014.

Planned Improvements

Several items are being evaluated to improve the CH_4 and N_2O emission estimates from stationary combustion and to reduce uncertainty for U.S. Territories. 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 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 combustion estimates from U.S. Territories.

Fuel use was adjusted for the industrial sector to subtract out construction and agricultural use, which is reported under mobile sources. Mobile source CH_4 and N_2O also include emissions from sources that may be captured as

part of the commercial sector. Future research will look into the need to adjust commercial sector fuel consumption to account for sources included elsewhere.

Future improvements to the CH_4 and N_2O from Stationary Combustion category involve continued research into the availability of using CH_4 and N_2O from stationary combustion data from other sources, for example, 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.[138]

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.[139]

Emission factors for gasoline and diesel on-road vehicles utilizing Tier 2 and Low Emission Vehicle (LEV) technologies were developed by ICF (2006b); all other gasoline and diesel on-road vehicle emissions factors were developed by ICF (2004). These factors were derived from EPA, California Air Resources Board (CARB) and Environment Canada laboratory test results of different vehicle and control technology types. The EPA, CARB and Environment Canada tests were designed following the Federal Test Procedure (FTP), which covers three separate driving segments, since vehicles emit varying amounts of greenhouse gases depending on the driving segment. These driving segments are: (1) a transient driving cycle that includes cold start and running emissions, (2) a cycle that represents running emissions only, and (3) a transient driving cycle that includes hot start and running emissions. For each test run, a bag was affixed to the tailpipe of the vehicle and the exhaust was collected; the content of this bag was then analyzed to determine quantities of gases present. The emissions characteristics of segment 2 were used to define running emissions, and subtracted from the total FTP emissions to determine start emissions. These were then recombined based upon the ratio of start to running emissions for each vehicle class from MOBILE6.2, an EPA emission factor model that predicts gram per mile emissions of CO_2, CO, HC, NO_x, and PM from vehicles under various conditions, to approximate average driving characteristics.[140]

Emission factors for AFVs were first 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

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[138] See <http://www.ipcc-nggip.iges.or.jp/public/tb/TFI_Technical_Bulletin_1.pdf>.

[139] 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.

[140] Additional information regarding the model can be found online at <https://www.epa.gov/moves/description-and-history-mobile-highway-vehicle-emission-factor-model>.

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 2015 were obtained from the Federal Highway Administration's (FHWA) Highway Performance Monitoring System database as reported in Highway Statistics (FHWA 1996 through 2016).[141] 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 2016) and information on total motor vehicle fuel consumption by fuel type from FHWA (1996 through 2016). VMT for AFVs were estimated based on Browning (2017). The age distributions of the U.S. vehicle fleet were obtained from EPA (2016b, 2000), and the average annual age-specific vehicle mileage accumulation of U.S. vehicles were obtained from EPA (2016b).

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 Mobile Sources

To estimate emissions from non-road mobile sources, 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).[142] Activity data were obtained from AAR (2008 through 2016), APTA (2007 through 2016), APTA (2006), BEA (1991 through 2015), Benson (2002 through 2004), DHS (2008), DLA Energy (2015), DOC (1991 through 2015), DOE (1993 through 2015), DOT (1991 through 2016), EIA (2002, 2007, 2016a), EIA (2007 through 2016), EIA (1991 through 2016), EPA (2016b), Esser (2003 through 2004), FAA (2017), FHWA (1996 through 2016), [143,144] Gaffney (2007), and Whorton (2006 through 2014). Emission factors for non-road modes were taken from IPCC (2006) and Browning (2009).

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 2015 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

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[141] The source of VMT is FHWA Highway Statistics Table VM-1. 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 through 2010 Inventory and apply to the 2007 through 2015 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 Inventory. These changes are reflected in a large drop in light-truck emissions between 2006 and 2007.

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

[143] In 2016, FHWA changed its methods for estimating the share of gasoline used in on-road and non-road applications. These method changes created a time-series inconsistency in this Inventory between 2015 and previous years in CH_4 and N_2O estimates for agricultural, construction, commercial, and industrial non-road mobile sources. The method updates are discussed further in the *Planned Improvements* section below.

[144] This Inventory uses FHWA's Agriculture, Construction, and Commercial/Industrial MF-24 fuel volumes along with the MOVES NONROAD model gasoline volumes to estimate non-road mobile source CH_4 and N_20 emissions for these categories. For agriculture, the MF-24 gasoline volume is used directly because it includes both off-road trucks and equipment. For construction and commercial/industrial gasoline estimates, the 2014 and older MF-24 volumes represented off-road trucks only; therefore, the MOVES NONROAD gasoline volumes for construction and commercial/industrial are added to the respective categories in the Inventory. Beginning in 2015, this addition is no longer necessary since the FHWA updated its methods for estimating on-road and non-road gasoline consumption. Among the method updates, FHWA now incorporates MOVES NONROAD equipment gasoline volumes in the construction and commercial/industrial categories

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 – Uncertainty Analysis of Emission Estimates. 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 2015 were estimated to be between 1.6 and 2.5 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 18 percent below to 27 percent above the corresponding 2015 emission estimate of 2.0 MMT CO_2 Eq. Also at a 95 percent confidence level, mobile combustion N_2O emissions from mobile sources in 2015 were estimated to be between 13.2 and 17.9 MMT CO_2 Eq., indicating a range of 13 percent below to 19 percent above the corresponding 2015 emission estimate of 15.1 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	2015 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	2.0	1.6	2.5	-18%	+27%
Mobile Sources	N_2O	15.1	13.2	17.9	-13%	+19%

[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.

QA/QC and Verification

A source-specific Quality Assurance/Quality Control 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 general (Tier 1) analysis, as well as portions of a category-specific (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 emission 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

Several updates were made to on-road CH_4 and N_2O emissions calculations this year resulting in a net increase to CH_4 and N_2O emissions from mobile combustion relative to the previous Inventory. First several light-duty trucks were re-characterized as heavy-duty vehicles based upon gross vehicle weight rating (GVWR) and confidential sales data. Second, which emission standards each vehicle type was assumed to have met were re-examined using confidential sales data. Also, in previous Inventories, non-plug-in hybrid electric vehicles (HEVs) were considered alternative fueled vehicles and therefore were not included in the engine technology breakouts. For this Inventory, HEVs are now classified as gasoline vehicles across the entire time series. PHEVs (plug-in hybrid electric vehicles) continue to be considered alternative fuel vehicles, as are electric vehicles. Estimates of alternative fuel vehicle

mileage for the last ten years were revised to reflect updates made to Energy Information Administration (EIA) data on alternative fuel use and vehicle counts. The energy economy ratios (EERs) in the alternative fuel vehicle analysis were also updated in this inventory. EERs are the ratio of the gasoline equivalent fuel economy of a given technology to that of conventional gasoline or diesel vehicles. These were updated to reflect the latest GREET model released in 2016 (ANL 2016). Overall, these changes resulted in an average annual increase of 0.02 MMT CO_2 Eq. (1 percent) in CH_4 emissions and an average annual increase of 0.5 MMT CO_2 Eq. (2 percent) in N_2O emissions from mobile combustion for the period 1990 through 2014, relative to the previous report.

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990 through 2015 with two recent notable exceptions. First, an update to the method for estimating on-road VMT created an inconsistency in on-road CH_4 and N_2O for the time periods 1990 to 2006 and 2007 to 2015. Second, an update to the method for estimating share of motor gasoline used in on-road and non-road applications created an inconsistency in non-road CH_4 and N_2O for the time periods 1990 to 2014 and 2015 (discussed in more detail in the Planned Improvements section below). Details on the emission trends and methodological inconsistencies through time are described in more detail in the Methodology section, above.

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.

- Evaluate and potentially update our method for estimating motor gasoline consumption for non-road mobile sources to improve accuracy and create a more consistent time series. As discussed in the Methodology section above and in Annex 3.2, CH_4 and N_2O estimates for gasoline-powered non-road sources in this Inventory are based on a variety of inputs, including FHWA Highway Statistics Table MF-24. In 2016, FHWA changed its methods for estimating the share of gasoline used in on-road and non-road applications.[145] These method changes created a time-series inconsistency in this Inventory between 2015 and previous years in CH_4 and N_2O estimates for agricultural, construction, commercial, and industrial non-road mobile sources. While we are still researching the effects of FHWA's method changes and cannot currently isolate them from underlying trends, we estimate that, in absence of the changes, CH_4 and N_2O emissions from non-road mobile sources would have likely increased by roughly 0.04 MMT CO_2 Eq. (roughly two percent increase) from 2014 to 2015, instead of the 0.06 MMT CO_2 Eq decrease (three percent decrease) shown in the time series in this Inventory; and would have increased by roughly 0.9 MMT CO_2 Eq (roughly 72 percent increase) from 1990 to 2015 instead of 0.8 MMT CO_2 Eq (63 percent increase). EPA received a comment on the draft version of this Inventory suggesting that we retrospectively apply the FHWA method updates for 2014 and earlier years. EPA plans to conduct further research to better understand FHWA's method updates and to consult EIA and FHWA regarding potential improvements to our method for estimating gasoline consumption for non-road mobile sources across the time series.
- Continue to explore potential improvements to estimates of domestic waterborne fuel consumption for future Inventories. 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 continues to be 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*, continues to be explored.
- 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

[145] The previous and new FHWA methodologies for estimating non-road gasoline are described in *Off-Highway and Public-Use Gasoline Consumption Estimation Models Used in the Federal Highway Administration*, Publication Number FHWA-PL-17-012. <https://www.fhwa.dot.gov/policyinformation/pubs/pl17012.pdf>

MOVES, such as vehicle age distributions by model year, MOVES is not used directly in calculating mobile source emissions. The use of MOVES is currently being evaluated to develop new CH_4 and N_2O emissions factors for on-road and non-road sources (including LPG and LNG non-road equipment), which may be integrated into future inventories. Other approaches for updating CH_4 and N_2O emissions factors, including use of the latest GREET model, are also being considered.

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).

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

There are several areas in which non-energy uses of fossil fuels are closely related to other parts of 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 2015 from the non-energy uses of fossil fuels were 125.5 MMT CO_2 Eq., which constituted approximately 2 percent of overall fossil fuel emissions. In 2015, the consumption of fuels for non-energy uses (after the adjustments described above) was 4,985.4 TBtu, an increase of 11.3 percent since 1990 (see Table 3-20). About 58.4 MMT (214.0 MMT CO_2 Eq.) of the C in these fuels was stored, while the remaining 34.2 MMT C (125.5 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	2011	2012	2013	2014	2015
Potential Emissions	312.1	377.5	318.0	312.9	328.9	324.2	339.5
C Stored	194.5	238.6	208.2	206.1	205.3	205.2	214.0
Emissions as a % of Potential	38%	37%	35%	34%	38%	37%	37%
Emissions	**117.6**	**138.9**	**109.8**	**106.7**	**123.6**	**119.0**	**125.5**

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, 2016) (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.[146,147] Consumption values were also adjusted to subtract net exports of intermediary chemicals.

For the remaining non-energy uses, the quantity of C stored was estimated by multiplying the potential emissions by a storage factor.

- For several fuel types—petrochemical feedstocks (including natural gas for non-fertilizer uses, LPG, pentanes plus, naphthas, other oils, still gas, special naphtha, and industrial other coal), asphalt and road oil, lubricants, and waxes—U.S. data on C stocks and flows were used to develop C storage factors, calculated as the ratio of (a) the C stored by the fuel's non-energy products to (b) the total C content of the fuel consumed. A lifecycle approach was used in the development of these factors in order to account for losses in the production process and during use. Because losses associated with municipal solid waste management are handled separately in the Energy 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	2011	2012	2013	2014	2015
Industry	**4,215.8**	**5,110.7**	**4,470.1**	**4,377.3**	**4,621.1**	**4,597.8**	**4,760.0**
Industrial Coking Coal	0.0	80.4	60.8	132.5	119.3	48.8	121.8
Industrial Other Coal	8.2	11.9	10.3	10.3	10.3	10.3	10.3
Natural Gas to Chemical Plants	281.6	260.9	297.1	292.7	297.0	305.1	302.3
Asphalt & Road Oil	1,170.2	1,323.2	859.5	826.7	783.3	792.6	831.7
LPG	1,120.5	1,610.0	1,865.6	1,887.3	2,062.9	2,109.7	2,157.7
Lubricants	186.3	160.2	141.8	130.5	138.1	144.0	156.8
Pentanes Plus	117.6	95.5	26.4	40.3	45.4	43.5	78.4
Naphtha (<401 °F)	326.3	679.5	469.4	432.3	498.8	435.2	417.9
Other Oil (>401 °F)	662.1	499.4	368.2	267.4	209.1	236.2	216.8
Still Gas	36.7	67.7	163.6	160.6	166.7	164.6	162.2
Petroleum Coke	27.2	105.2	0.0	0.0	0.0	0.0	0.0
Special Naphtha	100.9	60.9	21.8	14.1	96.6	104.5	97.0
Distillate Fuel Oil	7.0	11.7	5.8	5.8	5.8	5.8	5.8
Waxes	33.3	31.4	15.1	15.3	16.5	14.8	12.4
Miscellaneous Products	137.8	112.8	164.7	161.6	171.2	182.7	188.9
Transportation	**176.0**	**151.3**	**133.9**	**123.2**	**130.4**	**136.0**	**148.1**

[146] 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.

[147] 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.

Lubricants	176.0	151.3	133.9	123.2	130.4	136.0	148.1
U.S. Territories	**85.6**	**123.2**	**75.6**	**72.0**	**82.4**	**77.3**	**77.3**
Lubricants	0.7	4.6	1.0	1.0	1.0	1.0	1.0
Other Petroleum (Misc. Prod.)	84.9	118.6	74.6	71.0	81.4	76.2	76.2
Total	**4,477.4**	**5,385.2**	**4,679.7**	**4,572.5**	**4,833.9**	**4,811.1**	**4,985.4**

Table 3-21: 2015 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	**4,760.0**	**NA**	**88.1**	**NA**	**57.9**	**30.1**	**110.5**
Industrial Coking Coal	121.8	31.00	3.8	0.10	0.4	3.4	12.5
Industrial Other Coal	10.3	25.82	0.3	0.65	0.2	0.1	0.3
Natural Gas to Chemical Plants	302.3	14.47	4.4	0.65	2.9	1.4	5.3
Asphalt & Road Oil	831.7	20.55	17.1	1.00	17.0	0.1	0.3
LPG	2157.7	17.06	36.8	0.65	24.6	12.2	44.6
Lubricants	156.8	20.20	3.2	0.09	0.3	2.9	10.5
Pentanes Plus	78.4	19.10	1.5	0.65	1.0	0.5	1.8
Naphtha (<401° F)	417.9	18.55	7.8	0.65	5.2	2.6	9.4
Other Oil (>401° F)	216.8	20.17	4.4	0.65	2.9	1.4	5.3
Still Gas	162.2	17.51	2.8	0.65	1.9	0.9	3.4
Petroleum Coke	+	27.85	+	0.30	+	+	+
Special Naphtha	97.0	19.74	1.9	0.65	1.3	0.6	2.3
Distillate Fuel Oil	5.8	20.17	0.1	0.50	0.1	0.1	0.2
Waxes	12.4	19.80	0.2	0.58	0.1	0.1	0.4
Miscellaneous Products	188.9	20.31	3.8	+	+	3.8	14.1
Transportation	**148.1**	**NA**	**3.0**	**NA**	**0.3**	**2.7**	**10.0**
Lubricants	148.1	20.20	3.0	0.09	0.3	2.7	10.0
U.S. Territories	**77.3**	**NA**	**1.5**	**NA**	**0.2**	**1.4**	**5.1**
Lubricants	1.0	20.20	+	0.09	+	+	0.1
Other Petroleum (Misc. Prod.)	76.2	20.00	1.5	0.10	0.2	1.4	5.0
Total	**4,985.4**		**92.6**		**58.4**	**34.2**	**125.5**

+ Does not exceed 0.05 TBtu, MMT C, MMT CO_2 Eq.
NA (Not Applicable)
[a] To avoid double counting, net exports have been deducted.
Note: Totals may not sum due to independent rounding.

Lastly, emissions were estimated by subtracting the C stored from the potential emissions (see Table 3-19). More detail on the methodology for calculating storage and emissions from each of these sources is provided in Annex 2.3.

Where storage factors were calculated specifically for the United States, data were obtained on (1) products such as asphalt, plastics, synthetic rubber, synthetic fibers, cleansers (soaps and detergents), pesticides, food additives, antifreeze and deicers (glycols), and silicones; and (2) industrial releases including energy recovery, Toxics Release Inventory (TRI) releases, hazardous waste incineration, and volatile organic compound, solvent, and non-combustion CO emissions. Data were taken from a variety of industry sources, government reports, and expert communications. Sources include EPA reports and databases such as compilations of air emission factors (EPA 2001), *National Emissions Inventory (NEI) Air Pollutant Emissions Trends Data* (EPA 2016a), *Toxics Release Inventory, 1998* (EPA 2000b), *Biennial Reporting System* (EPA 2000a, 2009), *Resource Conservation and Recovery Act Information System* (EPA 2013b, 2015b, 2016c), 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, 2013); the National Petrochemical & Refiners Association (NPRA 2002); the U.S. Census Bureau (1999, 2004, 2009, 2014); Bank of Canada (2012, 2013, 2014, 2016); Financial Planning Association (2006); INEGI (2006); the United States International Trade Commission (1990 through 2016); Gosselin, Smith, and Hodge (1984); EPA's *Municipal Solid Waste (MSW) Facts and Figures* (EPA 2013a; 2014a, 2016b); the Rubber Manufacturers' Association (RMA 2009, 2011, 2014, 2016); the International Institute of Synthetic Rubber Products (IISRP 2000, 2003); the Fiber Economics Bureau (FEB 2001, 2003, 2005, 2007, 2009, 2010, 2011, 2012, 2013); the EPA Chemical Data Access Tool (CDAT) (EPA 2014b); the American Chemistry Council (ACC 2003 through 2011, 2013, 2014, 2015a, 2016b); and the *Guide to the Business of Chemistry* (ACC 2012, 2015b, 2016a). 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 IPCC (2006), 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 2015 was estimated to be between 94.4 and 171.54 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 25 percent below to 37 percent above the 2015 emission estimate of 125.5 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	2015 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	72.5	48.9	123.4	-33%	70%
Asphalt	CO_2	0.3	0.1	0.6	-58%	123%
Lubricants	CO_2	20.6	17.0	23.9	-17%	16%
Waxes	CO_2	0.4	0.3	0.7	-29%	74%
Other	CO_2	31.8	18.7	34.0	-41%	7%
Total	**CO_2**	**125.5**	**94.4**	**171.5**	**-25%**	**37%**

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

Note: Totals may not sum due to independent rounding.

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

Source	Gas	2015 Storage Factor (%)	Uncertainty Range Relative to Emission Estimate[a] (%)		(%, Relative)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Feedstocks	CO_2	67%	53%	72%	-20%	8%
Asphalt	CO_2	99.6%	99.1%	99.8%	-0.5%	0.3%
Lubricants	CO_2	9%	4%	18%	-57%	91%
Waxes	CO_2	58%	49%	71%	-15%	22%
Other	CO_2	6%	6%	43%	-8%	572%

[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 2015 as discussed below. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific Quality Assurance/Quality Control 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 2014 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. Prior to 2001, the C balance inputs exceed outputs, then starting in 2001 through 2009, outputs exceeded inputs. In 2010 and 2011, inputs exceeded outputs, and in 2012, outputs slightly exceeded inputs. In 2013 through 2015, inputs exceeded outputs. A portion of this discrepancy has been reduced and two strategies have been developed to address the remaining portion (see Planned Improvements, below).

Recalculations Discussion

A number of updates to historical production values were included in the most recent Monthly Energy Review; these have been populated throughout this document.

The categorization of hazardous waste data have been revised in accordance with EPA's RCRAinfo Form Code List to correct the total number of tons burned for each waste type for years 2001 through 2014. The quantity of tons burned associated with the waste types Aqueous Waste, Organic Liquids and Sludges, Organic Solids, and Inorganic Solids has been revised to reflect the correct categorizations, resulting in increased historical emissions from hazardous waste incineration those years.

Planned Improvements

There are several improvements planned for the future:

- Analyzing the fuel and feedstock data from EPA's GHGRP to better disaggregate CO_2 emissions in NEU model and CO_2 process emissions from petrochemical production.
- 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, 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. 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 investigated 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

IPCC (2006) 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. [148] 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).[149]

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.[150] 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 allocate 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.

However, 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 IPPU chapter, as they were consumed during non-energy related industrial activity. Emissions from uses of fossil fuels as feedstocks

[148] 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).

[149] 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*.

[150] 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.

or reducing agents (e.g., petrochemical production, aluminum production, titanium dioxide and zinc production) are reported in the IPPU chapter, unless otherwise noted due to specific national circumstances.

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 Madtes 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 scrap tires. In the United States, incineration of MSW tends to occur 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, scrap tires are combusted for energy recovery in industrial and utility boilers, pulp and paper mills, and cement kilns. 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 in scrap tires—are of fossil origin. Plastics in the U.S. waste stream are primarily in the form of containers, packaging, and durable goods. Rubber is found in durable goods, such as carpets, and in non-durable goods, such as clothing and footwear. Fibers in municipal solid wastes are predominantly from clothing and home furnishings. As noted above, scrap tires (which contain synthetic 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 30.1 million metric tons of MSW were incinerated in the United States in 2014 (EPA 2016). Data for the amount of MSW incinerated in 2015 were not available, so data for 2015 was assumed to be equal to data for 2014. CO_2 emissions from incineration of waste rose 34 percent since 1990, to an estimated 10.7 MMT CO_2 Eq. (10,676 kt) in 2015, as the volume of scrap 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). Methane 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 2015, and have decreased by 32 percent since 1990. Nitrous oxide emissions from the incineration of waste were estimated to be 0.3 MMT CO_2 Eq. (1 kt N_2O) in 2015, and have decreased by 32 percent 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	2011	2012	2013	2014	2015
CO_2	**8.0**	**12.5**	**10.6**	**10.4**	**10.4**	**10.6**	**10.7**
Plastics	5.6	6.9	5.8	5.7	5.8	5.9	5.9
Synthetic Rubber in Tires	0.3	1.6	1.4	1.3	1.2	1.2	1.2
Carbon Black in Tires	0.4	2.0	1.7	1.5	1.4	1.4	1.5
Synthetic Rubber in MSW	0.9	0.8	0.7	0.7	0.7	0.7	0.7
Synthetic Fibers	0.8	1.2	1.1	1.1	1.3	1.3	1.3
CH_4	+	+	+	+	+	+	+
N_2O	**0.5**	**0.4**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**
Total	**8.4**	**12.8**	**10.9**	**10.7**	**10.7**	**10.9**	**11.0**

+ Does not exceed 0.05 MMT CO_2 Eq.

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

Gas/Waste Product	1990	2005	2011	2012	2013	2014	2015
CO_2	**7,950**	**12,469**	**10,564**	**10,379**	**10,398**	**10,608**	**10,676**
Plastics	5,588	6,919	5,757	5,709	5,815	5,928	5,928
Synthetic Rubber in Tires	308	1,599	1,363	1,261	1,158	1,189	1,220
Carbon Black in Tires	385	1,958	1,663	1,537	1,412	1,449	1,487
Synthetic Rubber in MSW	854	766	712	706	729	729	729
Synthetic Fibers	816	1,227	1,070	1,166	1,284	1,313	1,313
CH_4	+	+	+	+	+	+	+
N_2O	**2**	**1**	**1**	**1**	**1**	**1**	**1**

+ Does not exceed 0.5 kt

Methodology

Emissions of CO_2 from the incineration of waste include CO_2 generated by the incineration of plastics, synthetic fibers, and synthetic rubber in MSW, as well as the incineration of synthetic rubber and carbon black in scrap tires. The emission estimates are calculated for all four sources on a mass-basis based on the data available. These emissions were estimated by multiplying the mass 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, carbon black, and synthetic fibers. 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 scrap 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 in MSW, 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 *Advancing Sustainable Materials Management: Facts and Figures: Assessing Trends in Material Generation, Recycling and Disposal in the United States* (EPA 2015, 2016) and detailed unpublished backup data for some years not shown in the reports (Schneider 2007). For 2015, the amount of MSW incinerated was assumed to be equal to that in 2014, due to the lack of available data. The proportion of total waste discarded that is incinerated was derived from Shin (2014). Data on total waste incinerated was not available in detail for 2012 through 2015, so these values were assumed to equal to the 2011 value (Shin 2014). For synthetic rubber and carbon black in scrap tires, information was obtained from U.S. Scrap Tire Management Summary for 2005 through 2015 data (RMA 2016). 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 a weighted average of production statistics from 1990 to date. Information about scrap tire composition was taken from the Rubber Manufacturers' Association internet site (RMA 2012a). The mass of incinerated material is multiplied by its C content to calculate the total amount of carbon stored.

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). This percentage is multiplied by the carbon stored to estimate the amount of carbon emitted.

Incineration of waste, including MSW, also results in emissions of CH_4 and N_2O. These emissions were calculated as a function of the total estimated mass of waste incinerated and emission factors. As noted above, CH_4 and N_2O 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 2009 and 2010 were interpolated between 2008 and 2011 values. Data for 2011 were derived from Shin (2014). Data on total waste incinerated was not available in the *BioCycle* data set for 2012 through 2015, so these values were assumed to equal the 2011 *BioCycle* data set value.

Table 3-26 provides data on municipal solid waste discarded and percentage combusted for the total waste stream. The emission factors of N_2O and CH_4 emissions per quantity of municipal solid waste combusted are default emission factors for the default continuously-fed stoker unit MSW incineration technology type and were taken from IPCC (2006).

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

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%
2011	273,116,704	20,756,870	7.6%
2012	273,116,704[a]	20,756,870	7.6%
2013	273,116,704[a]	20,756,870	7.6%
2014	273,116,704[a]	20,756,870	7.6%
2015	273,116,704[a]	20,756,870	7.6%

[a] Assumed equal to 2011 value.
Source: van Haaren et al. (2010)

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 2015 were estimated to be between 9.6 and 12.1 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 10 percent below to 13 percent above the 2015 emission estimate of 10.7 MMT CO_2 Eq. Also at a 95 percent confidence level, waste incineration N_2O emissions in 2015 were estimated to be between 0.2 and 1.3 MMT CO_2 Eq. This indicates a range of 51 percent below to 330 percent above the 2015 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	2015 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
Incineration of Waste	CO_2	10.7	9.6	12.1	-10%	+13%
Incineration of Waste	N_2O	0.3	0.2	1.3	-51%	+330%

[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 2015 as discussed below. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific Quality Assurance/Quality Control plan was implemented for incineration of waste. This effort included a general (Tier 1) analysis, as well as portions of a category-specific (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 for 2014 have been updated based on *Advancing Sustainable Materials Management: 2014 Fact Sheet* (EPA 2016). The data used to calculate the percent incineration was not 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 published in Shin (2014). This provided updated incineration data for 2011, so the generation and incineration data for 2012 through 2015 are assumed equivalent to the 2011 values. The data for 2009 and 2010 were based on interpolations between 2008 and 2011.

A transcription error in 2013 plastics production data from EPA's *Advancing Sustainable Materials Management: Facts and Figures 2013: Assessing Trends in Material Generation, Recycling and Disposal in the United States* (EPA 2015) was identified and corrected. The amount of HDPE discarded in 2013 was misreported and the value has been updated. This update results in updated emission estimate for the CO_2 from Plastics for 2013.

Previously, the carbon content for synthetic fiber was assumed to be the weighted average of carbon contents of four fiber types (polyester, nylon, olefin, and acrylic) based on 1999 fiber production data. This methodology has been updated. A weighted average for the carbon content of synthetic fibers based on production data from 1990 through 2015 was developed for each year based on the amount of fiber produced. For each year, the weighted average carbon content was used to develop the amount of carbon emitted. This methodology update affects the synthetic fiber CO_2 estimates.

Planned Improvements

The availability of facility-level waste incineration data through EPA's Greenhouse Gas Reporting Program (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,[151] some facility-level waste incineration emissions reported under EPA's 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.[152] 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.

If GHGRP data would not provide a more accurate estimate of the amount of solid waste combusted, new data sources for the total MSW generated will be explored given that the data previously published semi-annually in *BioCycle* (van Haaren et al. 2010) has ceased to be published, according to the authors. Equivalent data was derived from Shin (2014) for 2011. A new methodology would be developed considering the available data within the annual update of EPA's *Advancing Sustainable Materials Management: Facts and Figures 2014: Assessing Trends in Material Generation, Recycling and Disposal in the United States* (EPA 2016) and a report from the Environmental Research & Education Foundation (2016), MSW Management in the U.S.: 2010 & 2013, that has data for 2010 and 2013. In developing the new methodology, appropriate assumptions would need to be made to ensure that the MSW figures include the same boundaries. Consideration would also be made to be consistent with calculations in other waste categories including landfilling and composting.

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 source category. Waste incineration activities that do not include energy recovery will be examined. Synthetic fibers within scrap tires are not included in this analysis and will be explored for future Inventories. The carbon content of fibers within scrap tires would be used to calculate the associated incineration emissions. Updated fiber content data from the Fiber Economics Bureau will also be explored.

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 production, underground coal mines contribute the largest share of CH_4 emissions (see Table 3-29 and Table 3-30) due to the higher CH_4 content of coal in the deeper underground coal seams. In 2015, 305 underground coal mines and 529 surface mines were operating in the United States. In recent years the total number of active coal mines in the United States has declined. In 2015, the United States was the second largest coal producer in the world (812 MMT), after China (3,527 MMT) and followed by India (691 MMT) (IEA 2016).

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

[152] See <http://www.ipcc-nggip.iges.or.jp/public/tb/TFI_Technical_Bulletin_1.pdf>.

Table 3-28: Coal Production (kt)

Year	Underground		Surface		Total	
	Number of Mines	Production	Number of Mines	Production	Number of Mines	Production
1990	1,683	384,244	1,656	546,808	3,339	931,052
2005	586	334,398	789	691,448	1,398	1,025,846
2011	508	313,529	788	684,807	1,296	998,337
2012	488	310,608	719	610,307	1,207	920,915
2013	395	309,546	637	581,270	1,032	890,815
2014	345	321,783	613	583,974	958	905,757
2015	305	278,342	529	534,127	834	812,469

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. CH_4 emissions are normally a function of coal rank (a classification related to the percentage of carbon in the coal) and depth. Surface coal mines typically produce lower-rank coals and remove less than 250 feet of overburden, so their 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 2015 were estimated to be 2,436 kt (60.9 MMT CO_2 Eq.), a decline of 37 percent since 1990 (see Table 3-29 and Table 3-30). Of this amount, underground mines accounted for approximately 73 percent, surface mines accounted for 14 percent, and post-mining emissions accounted for 13 percent.

Table 3-29: CH_4 Emissions from Coal Mining (MMT CO_2 Eq.)

Activity	1990	2005	2011	2012	2013	2014	2015
Underground (UG) Mining	74.2	42.0	50.2	47.3	46.2	46.4	44.6
Liberated	80.8	59.7	71.0	65.8	64.5	63.1	60.5
Recovered & Used	(6.6)	(17.7)	(20.8)	(18.5)	(18.3)	(16.7)	(15.9)
Surface Mining	10.8	11.9	11.6	10.3	9.7	9.6	8.7
Post-Mining (UG)	9.2	7.6	6.9	6.7	6.6	6.7	5.8
Post-Mining (Surface)	2.3	2.6	2.5	2.2	2.1	2.1	1.9
Total	**96.5**	**64.1**	**71.2**	**66.5**	**64.6**	**64.8**	**60.9**

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

Table 3-30: CH_4 Emissions from Coal Mining (kt)

Activity	1990	2005	2011	2012	2013	2014	2015
UG Mining	2,968	1,682	2,008	1,891	1,849	1,854	1,783
Liberated	3,234	2,390	2,839	2,631	2,580	2,523	2,421
Recovered & Used	(266)	(708)	(831)	(740)	(730)	(668)	(638)
Surface Mining	430	475	465	410	388	386	347
Post-Mining (UG)	368	306	276	268	263	270	231
Post-Mining (Surface)	93	103	101	89	84	84	75
Total	**3,860**	**2,565**	**2,849**	**2,658**	**2,584**	**2,593**	**2,436**

Notes: 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:

- Estimate emissions from underground mines. These emissions have two sources: ventilation systems and degasification systems. They are estimated using mine-specific data, then summed to determine total CH_4 liberated. The CH_4 recovered and used is then subtracted from this total, resulting in an estimate of net emissions to the atmosphere.
- Estimate CH_4 emissions from surface mines and post-mining activities. Unlike 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

To estimate CH_4 liberated from ventilation systems, EPA uses data collected through its Greenhouse Gas Reporting Program (GHGRP)[153] (subpart FF, "Underground Coal Mines"), data provided by the U.S. Mine Safety and Health Administration (MSHA), and occasionally data collected from other sources on a site-specific level (e.g., state gas production databases). Since 2011, the nation's "gassiest" underground coal mines—those that liberate more than 36,500,000 actual cubic feet of CH_4 per year (about 14,700 MT CO_2 Eq.)—have been required to report to EPA's GHGRP (EPA 2016).[154] Mines that report to the GHGRP must report quarterly measurements of CH_4 emissions from ventilation systems to EPA; they have the option of recording their own measurements, or using the measurements taken by MSHA as part of that agency's quarterly safety inspections of all mines in the United States with detectable CH_4 concentrations.[155]

Since 2013, ventilation emission estimates have been calculated based on both GHGRP data submitted by underground mines, and on quarterly measurement data obtained directly from MSHA for the remaining mines. The quarterly measurements are used to determine the average daily emissions rate for the reporting year quarter. Because not all mines report under the GHGRP, the emissions of the mines that do not report must be calculated using MSHA data. The MSHA data also serves as a quality assurance tool for validating GHGRP data.

Step 1.2: Estimate CH_4 Liberated from Degasification Systems

Particularly gassy 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. Twenty-six mines used degasification systems in 2015, and the CH_4 removed through these systems was reported to EPA's GHGRP (EPA 2016). Based on the weekly measurements reported to EPA's GHGRP, degasification data summaries for each mine were added together to estimate the CH_4 liberated from degasification systems. Sixteen of

[153] In implementing improvements and integrating data from EPA's GHGRP, the EPA followed the latest guidance from the IPCC on the use of facility-level data in national inventories (IPCC 2011).

[154] Underground coal mines report to EPA under Subpart FF of the GHGRP. In 2015, 123 underground coal mines reported to the program.

[155] 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.

the 26 mines with degasification systems had operational CH_4 recovery and use projects (see step 1.3 below), and GHGRP reports show the remaining ten mines vented CH_4 from degasification systems to the atmosphere.[156]

Degasification volumes for the life of any pre-mining wells are attributed to the mine as emissions in the year in which the well is mined through.[157] EPA's GHGRP does not require gas production from virgin coal seams (coalbed methane) to be reported by coal mines under subpart FF. Most pre-mining wells drilled from the surface are considered coalbed methane wells and are reported under another subpart of the program (subpart W, "Petroleum and Natural Gas Systems"). As a result, for the 10 mines with degasification systems that include pre-mining wells, GHGRP information was supplemented with historical data from state gas well production databases (DMME 2016; GSA 2016; WVGES 2016), as well as with mine-specific information regarding the dates on which the pre-mining wells are mined through (JWR 2010; El Paso 2009).

Degasification information reported to EPA's GHGRP by underground coal mines was the primary source of data used to develop estimates of CH_4 liberated from degasification systems. Data reported to EPA's GHGRP were used to estimate CH_4 liberated from degasification systems at 21 of the 26 mines that employed degasification systems in 2015. For the other five mines (all with pre-mining wells from which CH_4 was recovered), GHGRP data—along with supplemental information from state gas production databases (DMME 2016; GSA 2016; WVGES 2016) — were used to estimate CH_4 liberated from degasification systems. For one mine, due to a lack of mine-provided information used in prior years and a GHGRP reporting discrepancy, the CH_4 liberated was based on both an estimate from historical mine-provided CH_4 recovery and use rates and state gas sales records.

Step 1.3: Estimate CH_4 Recovered from Ventilation and Degasification Systems, and Utilized or Destroyed (Emissions Avoided)

Sixteen mines had CH_4 recovery and use projects in place in 2015. Fourteen of these mines sold the recovered CH_4 to a pipeline, including one that also used CH_4 to fuel a thermal coal dryer. In addition, one mine used recovered CH_4 for electrical power generation, and one used recovered CH_4 to heat mine ventilation air.

Ten of the 16 mines deployed degasification systems in 2015; for those mines, estimates of CH_4 recovered from the systems were exclusively based on GHGRP data. Based on weekly measurements, the GHGRP degasification destruction data summaries for each mine were added together to estimate the CH_4 recovered and used from degasification systems.

All 10 mines with degasification systems used pre-mining wells as part of those systems, but only four of them intersected pre-mining wells in 2015. GHGRP and supplemental data were used to estimate CH_4 recovered and used at two of these four mines; supplemental data alone (GSA 2016) were used for the other two mines, which reported to EPA's GHGRP as a single entity. Supplemental information was used for these four mines because estimating CH_4 recovery and use from pre-mining wells requires additional data (not reported under subpart FF of EPA's GHGRP; see discussion in step 1.2 above) to account for the emissions avoided. The supplemental data came from state gas production databases as well as mine-specific information on the timing of mined-through pre-mining wells.

GHGRP information was not used to estimate CH_4 recovered and used at two mines. At one of these mines, a portion of reported CH_4 vented was applied to an ongoing mine air heating project. Because of a lack of mine-provided information used in prior years and a GHGRP reporting discrepancy, the 2015 CH_4 recovered and used from pre-mining wells at the other mine was based on an estimate from historical mine-provided CH_4 recovery and use rates. Emissions recovered and used from the active mine degasification system were estimated based on a state gas production data information system.

In 2015, one mine destroyed a portion of its CH_4 emissions from ventilation systems using thermal oxidation technology. The amount of CH_4 recovered and destroyed by the project was determined through publicly-available emission reduction project information (ACR 2016).

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[156] Several of the mines venting CH_4 from degasification systems use a small portion the gas to fuel gob well blowers in remote locations where electricity is not available. However, this CH_4 use is not considered to be a formal recovery and use project.

[157] A well is "mined through" when coal mining development or the working face intersects the borehole or well.

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

Mine-specific data are 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* (EIA 2016) was multiplied by basin-specific CH_4 contents (EPA 1996, 2005) and a 150 percent emission factor (to account for CH_4 from over- and under-burden) to estimate CH_4 emissions (King 1994; Saghafi 2013). For post-mining activities, basin-specific coal production was multiplied by basin-specific gas contents and a mid-range 32.5 percent emission factor for CH_4 desorption during coal transportation and storage (Creedy 1993). Basin-specific *in situ* gas content data were compiled from AAPG (1984) and USBM (1986).

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 EPA's GHGRP or from MSHA, uncertainty is relatively low. A degree of imprecision was introduced because the ventilation air measurements used were not continuous but rather quarterly instantaneous readings that were used to determine the average daily emissions rate for the quarter. 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 were used for a significant number of the mines that reported their own measurements to the program beginning in 2013; however, the equipment uncertainty is applied to both GHGRP and MSHA data.

Estimates of CH_4 recovered by degasification systems are relatively certain for utilized CH_4 because of the availability of GHGRP data and gas sales information. 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.

EPA's GHGRP requires weekly CH_4 monitoring of mines that report degasification systems, and continuous CH_4 monitoring is required for utilized CH_4 on- or off-site. Since 2012, GHGRP data have been used to estimate CH_4 emissions from vented degasification wells, reducing the uncertainty associated with prior MSHA estimates used for this subsource. Beginning in 2013, GHGRP data were also used for determining CH_4 recovery and use at mines without publicly available gas usage or sales records, which has reduced the uncertainty from previous estimation methods that were based on information from coal industry contacts.

In 2015 a small level of uncertainty was introduced with using estimated rather than measured values of recovered methane from two of the mines with degasification systems. An increased level of uncertainty was applied to these two subsources, but the change had little impact on the overall uncertainty.

Surface mining and post-mining emissions are associated with considerably more uncertainty than underground mines, because of the difficulty in developing accurate emission factors from field measurements. However, since underground emissions constitute 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 2015 were estimated to be between 53.3 and 70.8 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 12.5 percent below to 16.2 percent above the 2015 emission estimate of 60.9 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	2015 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	60.9	53.3	70.8	-12.5%	+16.2%

[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 consistency from 1990 through 2015. Details on the emission trends through time are described in more detail in the methodology section.

Recalculations Discussion

For the current Inventory, revisions were made to the 2013 and 2014 underground liberated and recovered emissions. From 2013 to 2015, recovered emissions reported to EPA's GHGRP for a large mine located in Virginia were inaccurate and could not be used. For the 1990 through 2013 and 1990 through 2014 Inventories, EPA estimated recovered emissions for this mine based on a five-year historical average. In preparing the current Inventory, EPA was able to utilize the Virginia Division of Gas and Oil Data Information System (DGO DIS) to estimate recovered degasification emissions for the Virginia mine based on published well production. The well production data was more accurate than the reported values in 2013, 2014, and 2015; thus 2013 and 2014 were revised using the 2015 methodology. The DGO DIS will continue to be used in future years until the GHGRP reported values can be verified for this mine.

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 2015, 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 gassy mine[158] 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 six gassy mine closures in 2015. In 2015, gross abandoned mine emissions increased slightly from 8.7 to 9.0 MMT CO_2 Eq. (see Table 3-32 and Table 3-33). Gross emissions are reduced by CH_4 recovered and used at 40 mines, resulting in net emissions in 2015 of 6.4 MMT CO_2 Eq.

[158] A mine is considered a "gassy" mine if it emits more than 100 thousand cubic feet of CH_4 per day (100 mcfd).

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

Activity	1990	2005	2011	2012	2013	2014	2015
Abandoned Underground Mines	7.2	8.4	9.3	8.9	8.8	8.7	9.0
Recovered & Used	+	1.8	2.9	2.7	2.6	2.4	2.6
Total	**7.2**	**6.6**	**6.4**	**6.2**	**6.2**	**6.3**	**6.4**

+ 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	2011	2012	2013	2014	2015
Abandoned Underground Mines	288	334	373	358	353	350	359
Recovered & Used	+	70	116	109	104	97	102
Total	**288**	**264**	**257**	**249**	**249**	**253**	**256**

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

Methodology

Estimating CH_4 emissions from an abandoned coal mine requires predicting the emissions of a mine from the time of abandonment through the inventory year of interest. The flow of CH_4 from the coal to the mine void is primarily dependent on the mine's emissions when active and the extent to which the mine is flooded or sealed. The CH_4 emission rate before abandonment reflects the gas content of the coal, the 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/year
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 emissions 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 will 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
q_i	=	Initial gas flow rate at time zero (t_o), mmcfd
D	=	Decline rate, 1/year
t	=	Elapsed time from t_o (years)

Seals have an inhibiting effect on the rate of flow of CH_4 into the atmosphere compared to the 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 about 98 percent of all CH_4 emissions. This same relationship is assumed for abandoned mines. It was determined that the 524 abandoned mines closed after 1972 produced emissions greater than 100 mcfd when active. Further, the status of 302 of the 524 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 in 2015, grouped by Class according to Post-Abandonment State

Basin	Sealed	Vented	Flooded	Total Known	Unknown	Total Mines
Central Appl.	40	26	52	118	143	261
Illinois	34	3	14	51	30	81
Northern Appl.	46	22	16	84	39	123
Warrior Basin	0	0	16	16	0	16
Western Basins	28	3	2	33	10	43
Total	**148**	**54**	**100**	**302**	**222**	**524**

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 (MSHA 2016). 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 2015. Since the sample of gassy mines 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 2015, 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 2015 were estimated to be between 5.2 and 7.9 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 18 percent below to 24 percent above the 2015 emission estimate of 6.4 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	2015 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	6.4	5.2	7.9	-18%	+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 2015. 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 these activities, CH_4 is 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 emissions from petroleum systems in 2015 were 39.9 MMT CO_2 Eq. (1,595 kt). Total CO_2 emissions from petroleum systems in 2015 were 3.6 MMT CO_2 Eq. (3,567 kt).

Production Field Operations. Production field operations account for approximately 98 percent of total CH_4 emissions from petroleum systems. The predominant sources of emissions from production field operations are pneumatic controllers, offshore oil platforms, associated gas venting and flaring, gas engines, chemical injection pumps, oil tanks, hydraulically fractured oil well completions, and fugitives from oil wellheads. These sources alone emit around 95 percent of the production field operations emissions. The remaining emissions are distributed among around 20 additional activities.

Since 1990, CH_4 emissions from production field operations have decreased by 29 percent, due to a large decrease in associated gas venting. Production segment methane emissions have decreased by around 8 percent from 2014 levels, primarily due to decreases in emissions from associated gas venting and flaring, and in the number of hydraulically fractured oil wells that were completed in 2015 compared to 2014.

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 approximately 1 percent of the emissions. The principal sources of CO_2 emissions are oil tanks, pneumatic controllers, chemical injection pumps, and offshore oil platforms. These four sources together account for slightly over 97 percent of the non-combustion CO_2 emissions from production field operations, while the remaining 3 percent of the emissions is distributed among around 20 additional activities. Due to the activity data source for CO_2 from flaring, it is not possible to develop separate estimates for flaring occurring in natural gas production and flaring occurring in oil production. Total CO_2 emissions from flaring for both natural gas and oil were 18.0 MMT CO_2 in 2015 and are included in the Natural Gas Systems estimates.

Crude Oil Transportation. Crude oil transportation activities account for less than 1 percent of total CH_4 emissions from the oil industry. Venting emissions, including from tanks, truck loading, rail loading, and marine vessel loading operations account for 89 percent of CH_4 emissions from crude oil transportation. Fugitive emissions, almost entirely from floating roof tanks, account for approximately 11 percent of CH_4 emissions from crude oil transportation.

Since 1990, CH_4 emissions from transportation have increased by 28 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 from transportation in 2015 increased by approximately 2 percent from 2014 levels.

Crude Oil Refining. Crude oil refining processes and systems account for approximately 2 percent of total CH_4 emissions from the oil industry. This low share is due to the fact that 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, incomplete combustion accounts for around 50 percent of the CH_4 emissions, while vented and fugitive emissions account for approximately 34 and 15 percent, respectively. Flaring accounts for 82 percent of combustion CH_4 emissions. Refinery system blowdowns for maintenance and process vents are the primary venting contributors (97 percent). Most of the fugitive CH_4 emissions from refineries are from equipment leaks and storage tanks (87 percent).

Methane emissions from refining of crude oil have increased by approximately 7 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 from crude oil refining have fluctuated between 24 and 28 kt.

Flare emissions from crude oil refining accounts for slightly more than 77 percent of the total CO_2 emissions in petroleum systems. Refinery CO_2 emissions decreased by approximately 7 percent from 1990 to 2015.

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

Activity	1990	2005	2011	2012	2013	2014	2015
Production							
Pneumatic controller venting	19.1	17.1	16.1	14.8	17.8	18.5	18.6
Offshore platforms	5.3	4.6	4.7	4.7	4.7	4.7	4.7
Associated gas venting and flaring	17.1	14.4	16.2	14.7	9.0	6.0	3.7
Tanks	6.2	2.0	1.2	1.4	1.6	1.9	2.0
Gas Engines	2.1	1.7	1.9	2.1	2.1	2.3	2.3
Other Sources	4.9	5.3	7.1	8.0	8.3	8.9	7.7
Production Total	**54.7**	**45.2**	**47.2**	**45.6**	**43.6**	**42.2**	**39.0**
Crude Oil Transportation	**0.2**	**0.1**	**0.1**	**0.2**	**0.2**	**0.2**	**0.2**
Refining	**0.6**	**0.7**	**0.7**	**0.7**	**0.6**	**0.6**	**0.6**
Total	**55.5**	**46.0**	**48.0**	**46.4**	**44.5**	**43.0**	**39.9**

Note: Totals may not sum due to independent rounding.

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

Activity	1990	2005	2011	2012	2013	2014	2015
Production Field Operations							
Pneumatic controller venting	764	683	643	593	714	740	745
Offshore platforms	211	185	188	188	188	188	188
Associated gas venting and flaring	685	576	647	587	361	239	148
Tank venting	248	82	48	55	64	74	80
Gas Engines	85	70	78	82	86	90	90
Other Sources	195	213	285	319	334	357	309
Production Field Operations	**2,188**	**1,808**	**1,888**	**1,825**	**1,746**	**1,689**	**1,561**
Crude Oil Transportation	**7**	**5**	**5**	**6**	**7**	**8**	**8**
Refining	**24**	**27**	**28**	**27**	**26**	**24**	**26**
Total	**2,218**	**1,840**	**1,922**	**1,858**	**1,778**	**1,721**	**1,595**

Note: Totals may not sum due to independent rounding.

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

Activity	1990	2005	2011	2012	2013	2014	2015
Production	0.4	0.3	0.4	0.5	0.6	0.6	0.6
Crude Refining	3.2	3.6	3.8	3.4	3.1	2.9	2.9
Total	**3.6**	**3.9**	**4.2**	**3.9**	**3.7**	**3.6**	**3.6**

Note: Totals may not sum due to independent rounding.

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

Activity	1990	2005	2011	2012	2013	2014	2015
Production	391	338	395	473	550	640	640
Crude Refining	3,162	3,589	3,797	3,404	3,143	2,927	2,927
Total	**3,553**	**3,927**	**4,192**	**3,876**	**3,693**	**3,567**	**3,567**

Note: Totals may not sum due to independent rounding.

Methodology

The estimates of CH_4 emissions from petroleum systems are largely based on GRI/EPA 1996, EPA 1999, DrillingInfo, and GHGRP data (2010 through 2015). Petroleum Systems includes emission estimates for activities occurring in petroleum systems from the oil wellhead through crude oil refining, including activities for crude oil production field operations, crude oil transportation activities, and refining operations. Annex 3.5 provides further detail on the emission estimates for these activities. The estimates of CH_4 emissions from petroleum systems do not include emissions downstream of oil refineries because these emissions are considered to be negligible.

Emissions are estimated for each activity by multiplying emission factors (e.g., emission rate per equipment or per activity) by corresponding activity data (e.g., equipment count or frequency of activity).

References for emission factors include *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), DrillingInfo (2015), consensus of industry peer review panels, Bureau of Ocean Energy Management (BOEM) (formerly Bureau of Ocean Energy Management, Regulation, and Enforcement [BOEMRE]) reports (BOEMRE 2004; BOEM 2011), analysis of BOEMRE data (EPA 2005; BOEMRE 2004), and the GHGRP (2010 through 2015).

The emission factors for pneumatic controllers and chemical injection pumps were developed using GHGRP data for reporting year 2014. The emission factors for tanks, and associated gas venting and flaring were developed using GHGRP data for reporting year 2015. Emission factors for hydraulically fractured (HF) oil well completions (controlled and uncontrolled) were developed using DrillingInfo data analyzed for the 2015 NSPS OOOOa proposal (EPA 2015a). For offshore oil production, two emission factors were calculated using data collected for all federal offshore platforms (EPA 2015b; BOEM 2014), one for oil platforms in shallow water, and one for oil platforms in deep water. For all sources other than associated gas venting and flaring, emission factors are held constant for the period 1990 through 2015, and trends in emissions reflect changes in activity levels. For associated gas venting and flaring, year-specific emission factors were developed for 2011-2015 and the 2011 emission factors were applied back to 1990. Emission factors from EPA 1999 are used for all other production and transportation activities.

References for activity data include DrillingInfo (2016), the Energy Information Administration annual and monthly reports (EIA 1990 through 2016), (EIA 1995 through 2016a, 2016b), *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 2016), the Interstate Oil and Gas Compact Commission (IOGCC 2012), the United States Army Corps of Engineers, (1995 through 2016), and the GHGRP (2010 through 2015).

For many sources, complete activity data were not available for all years of the time series. In such cases, one of three approaches was employed to estimate values, consistent with IPCC good practice. Where appropriate, the activity data were calculated from related statistics using ratios developed based on EPA 1996, and/or GHGRP data. For floating roof tanks, the activity data were held constant from 1990 through 2015 based on EPA (1999). In some cases, activity data are developed by interpolating between recent data points (such as from GHGRP) and earlier data points, such as from GRI 1996. Lastly, the previous year's data were used for domestic barges and tankers as current year were not yet available. For offshore production, the number of platforms in shallow water and the number of platforms in deep water are used as activity data and are taken from BOEM datasets (BOEM 2011a, b, c).

A complete list of references for emission factors and activity data by emission source is provided in Annex 3.5.

For petroleum refining activities, 2010 to 2015 emissions were directly obtained from EPA's GHGRP. All U.S. refineries have been required to report CH_4 and CO_2 emissions for all major activities starting with emissions that occurred in 2010. The national total of these emissions for each activity was used for the 2010 to 2015 emissions. The national emission total for each activity was divided by refinery feed rates for those inventory years to develop an average activity-specific emission factor, which was used to estimate national emissions for each refinery activity from 1990 to 2009 based on national refinery feed rates for each year (EPA 2015c).

In this year's Inventory, EPA has held constant the CO_2 values from the previous Inventory (developed using the methodology as described in this section) as it assesses improvements to the CO_2 estimates. See Planned Improvements. The methodology for estimating CO_2 emissions from petroleum systems includes calculation of vented, fugitive, and process upset emissions sources from 26 activities for crude oil production field operations and three activities from petroleum refining. Generally, emissions are estimated for each activity by multiplying CO_2 emission factors by the corresponding CH_4 data, as the CO_2 content of gas relates to the CH_4 content of gas. The production field operations 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 emission factors for offshore oil production (shallow and deep water), which were derived using data from BOEM (EPA 2015b; BOEM 2014). For the three petroleum refining activities (i.e., flares, asphalt blowing, and process vents); the CO_2 emissions data for 2010 to 2014 were directly obtained from the GHGRP. The 2010 to 2013 CO_2 emissions data from GHGRP 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) which were then applied to the annual refinery feed to estimate CO_2 emissions for 1990 to 2009. In this year's Inventory, EPA has held constant the CO_2 values from the previous Inventory (developed using the methodology as described in this paragraph) as it assesses improvements to the CO_2 estimates. See Planned Improvements.

Uncertainty and Time-Series Consistency

The most recent uncertainty analysis for the petroleum systems emission estimates in the Inventory was conducted for the 1990 to 2009 Inventory that was released in 2011, and has not yet been updated. Since the analysis was last conducted, several of the methods used in the Inventory have changed to reflect improved data and changes in industry practices and equipment. In addition, new studies and other data sources such as those discussed in the sections below offer improvement to understanding and quantifying the uncertainty of some emission source estimates. EPA is preparing a draft update to the uncertainty analysis conducted for the 2011 Inventory to reflect the new information and will seek stakeholder feedback on the draft analysis as part of the development of the next (i.e., 1990 through 2016) Inventory. For more information, please see the Planned Improvements section.

To develop the values in Table 3-40 below, EPA has applied the uncertainty percentage ranges calculated previously to the updated 2015 emission estimates. To develop the uncertainty percentage ranges, EPA used 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 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 emission estimates for this category evolves and improves as the underlying methodologies and datasets improve.

Given the recent revisions, the uncertainty ranges applied may not reflect the uncertainty associated with the recently revised emission factors and activity data sources.

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 2015, based on the previously conducted uncertainty assessment using the recommended IPCC methodology. The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-40. Petroleum systems CH_4 emissions in 2015 were estimated to be between 30.3 and 99.3 MMT CO_2 Eq., while CO_2 emissions were estimated to be between 2.7 and 8.9 MMT CO_2 Eq. at a 95 percent confidence level, based on previously calculated uncertainty. This indicates a range of 24 percent below to 149 percent above the 2015 emission estimates of 39.9 and 3.6 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	2015 Emission Estimate (MMT CO_2 Eq.)[b]	Uncertainty Range Relative to Emission Estimate[a] (MMT CO_2 Eq.)		(%)	
			Lower	Upper	Lower	Upper

			Bound	Bound	Bound	Bound
Petroleum Systems	CH_4	39.9	30.3	99.3	-24%	+149%
Petroleum Systems	CO_2	3.6	2.7	8.9	-24%	+149%

[a] Range of 2015 relative uncertainty, 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.

New data available starting in 2010 for refineries and in 2011 for other sources have improved estimates of emissions from Petroleum Systems. Many of the previously available data sets were collected in the 1990s. To develop a consistent time series for 1990 through 2015, for sources with new data, EPA reviewed available information on factors that may have resulted in changes over the time series (e.g., regulations, voluntary actions) and requested stakeholder feedback on trends as well. For most sources, EPA developed annual data for 1993-2010 by interpolating activity data or emission factors or both between 1992 and 2011 data points. Information on time-series consistency for sources updated in this year's Inventory can be found in the Recalculation Discussion below, with additional detail provided in the *2017 Production Memo*. For information on other sources, please see the Methodology Discussion 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. The EPA has a multi-step data verification process for GHGRP data, including automatic checks during data-entry, statistical analyses on completed reports, and staff review of the reported data. Based on the results of the verification process, the EPA follows up with facilities to resolve mistakes that may have occurred.[159]

As in previous years, EPA conducted early engagement and communication with stakeholders on updates prior to public review. In December 2016 and January 2017, EPA held stakeholder webinars on greenhouse gas data for oil and gas. In early 2017, EPA released memos detailing updates under consideration and requesting stakeholder feedback. In February 2017, EPA released a public review draft of the Inventory. Stakeholder feedback received through these processes is discussed in the Recalculations Discussion and Planned Improvements sections below.

In recent years, several studies have measured emissions at the source level and at the national or regional level and calculated emission estimates that may differ from the Inventory. 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, and studies that use tools such as inverse modeling to estimate the level of overall emissions needed to account for measured atmospheric concentrations of greenhouse gases at various scales. The first type of study can lead to direct improvements to or verification of Inventory estimates. In the past few years, EPA has reviewed and in many cases, incorporated data from these data sources. The second type of study can provide general indications on potential over- and under-estimates.

A key challenge in using these types of studies to assess Inventory results is having a relevant basis for comparison (i.e., the independent study should assess data from the Inventory and not another data set, such as EDGAR). In an effort to improve the ability to compare the national-level Inventory with measurement results that may be at other scales, a team at Harvard University along with EPA and other coauthors developed a gridded inventory of U.S. anthropogenic methane emissions with 0.1 degree x 0.1 degree spatial resolution, monthly temporal resolution, and

[159] See <https://www.epa.gov/sites/production/files/2015-07/documents/ghgrp_verification_factsheet.pdf>.

detailed scale-dependent error characterization.[160] The gridded methane inventory is designed to be consistent with the U.S. EPA *Inventory of U.S. Greenhouse Gas Emissions and Sinks (1990-2014)* estimates for the year 2012, which presents national totals for different source types.[161]

Recalculations Discussion

The EPA received information and data related to the emission estimates through GHGRP reporting, the annual Inventory formal public notice periods, stakeholder feedback on updates under consideration, and new studies. In January 2017, the EPA released a draft memorandum, *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2014: Revisions under Consideration for Natural Gas and Petroleum Systems Production Emissions*, referred to below as *2017 Production Memo*, that discussed changes under consideration for that segment, and requested stakeholder feedback on those changes.[162]

The EPA thoroughly evaluated relevant information available, and made updates to the production segment methodology for the Inventory including revised well count, equipment count, and pneumatic controller activity data, and revised activity and emissions data for tanks and associated gas venting and flaring. In addition, as the updates to emission factors resulted in calculation of net emissions (already taking into account any reduced emissions) for sources in petroleum production, EPA removed Gas STAR reductions from the calculations.

The combined impact of revisions to 2014 petroleum production segment CH_4 emissions, compared to the previous Inventory, is a decrease from 68 to 43 MMT CO_2 Eq. (25 MMT CO_2 Eq., or 37 percent).

The recalculations resulted in an average increase in emission estimates across the 1990 through 2014 time series, compared to the previous Inventory, of 1 MMT CO_2 Eq., or 6 percent. The recalculations resulted in increases in the emission estimate in early years of the time series, primarily due to recalculations related to associated gas venting and flaring, and decreases in the emission estimate in later years of the time series, primarily due to recalculations for pneumatic controllers.

In the current Inventory, EPA has held constant the CO_2 values from the previous Inventory (developed using the methodology as described in this section) as it assesses improvements to the CO_2 estimates. See Planned Improvements.

Production

This section references the memorandum, *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2015: Revisions for Natural Gas and Petroleum Systems Production Emissions* (*2017 Production Memo*), available at https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems-ghg-inventory-additional-information-1990-2015-ghg. This memorandum contains further details and documentation of recalculations.

Well Counts

EPA has used a more recent version and improved data processing of the DrillingInfo data set to update well counts data in the Inventory. For more information, see the *2017 Production Memo*. This update, which addressed a double-counting issue in last year's data set, resulted in a decrease of 37 percent in oil well counts on average over the time series. Stakeholder feedback on the public review draft of the Inventory and on the *2017 Production Memo* support the update to well counts data as it improves consistency with other recently published sources of well count data.

[160] See <https://www.epa.gov/ghgemissions/gridded-2012-methane-emissions>.

[161] See <https://www.epa.gov/ghgemissions/us-greenhouse-gas-inventory-report-1990-2014>.

[162] See <https://www.epa.gov/ghgemissions/updates-under-consideration-petroleum-and-natural-gas-systems-1990-2015-ghg-inventory>.

Table 3-41: Oil Well Count Data

Oil Well Count	1990	2005	2011	2012	2013	2014	2015
Number of Oil Wells	572,639	481,340	540,743	564,348	580,960	598,627	586,896
Previous Estimate	*904,675*	*764,371*	*838,899*	*867,375*	*884,652*	*898,268*	*NA*
Percent Change in Counts	**-37%**	**-37%**	**-36%**	**-35%**	**-34%**	**-33%**	**NA**

NA (Not Applicable)

Tanks

EPA developed emission estimates for oil tanks using GHGRP data and a throughput-based approach. For more information, please see the *2017 Production Memo*. Using 2015 GHGRP data, EPA developed a value for the fraction of petroleum production (MMbbl) sent to tanks (62.7 percent), and the fraction of petroleum sent to tanks that is in each tank category: large tanks with flares (55.5 percent), large tanks with VRU (20.1 percent), uncontrolled large tanks (17.6 percent), small tanks with flares (1.9 percent), and small tanks without flares (4.8 percent) for 2015. The fraction of petroleum production sent to tanks (62.7 percent) was held constant throughout the 1990 through 2015 time series. The percentages of petroleum production sent to tanks that was sent to large tanks (93.2 percent) and small tanks (6.8 percent) were also held constant throughout the 1990 through 2015 time series. The 2015 fraction of tank throughput in each control category was applied to for the years 2011 to 2015. For 1990, it was assumed that all throughput was sent to tanks in the uncontrolled categories. EPA then linearly interpolated from 1990 to 2011 for each category. Category-specific emission factors developed from 2015 GHGRP data were applied for every year of the time series. EPA also developed an emission factor for malfunctioning separator dump valves. In the GHGRP, only large tanks report malfunctioning dump valve emissions. EPA has applied the emission factor to all throughput in the large tank categories for each year of the time series. Stakeholder feedback on the public review draft of the Inventory and on the *2017 Production Memo* support the use of GHGRP data to calculate tank emissions and in particular the throughput approach, but recommended enhanced screening of GHGRP data. One stakeholder suggested that the tanks data underestimate tank emissions: the stakeholder suggested that the emission data and control efficiencies reported to GHGRP for this source may be inaccurate and that the methods and data do not take into account the full volume of emissions from stuck dump valves and other malfunctions. Another stakeholder noted that aerial survey observations should not be presumed to indicate an underestimation of tank emissions in EPA's GHGRP. Data are currently unavailable to assess malfunctions, to assess the Inventory data on stuck dump valves, or to use aerial observations to inform Inventory estimates for this source. See Planned Improvements.

The overall impact of the change is a decrease in calculated emissions of 45 percent on average over the time series, with smaller decreases in earlier years and larger decreases in recent years.

Table 3-42: National Tank Activity Data (MMbbl) by Category and National Emissions (Metric Tons CH_4)

Activity Data/Emissions	1990	2005	2011	2012	2013	2014	2015
Large Tanks w/ Flares (MMbbl)	0	470	716	822	946	1,106	1,197
Large Tanks w/ VRU (MMbbl)	0	171	260	298	343	401	434
Large Tanks w/o Control (MMbbl)	1,569	465	227	261	300	350	379
Small Tanks w/ Flares (MMbbl)	0	16	24	28	32	38	41
Small Tanks w/o Flares (MMbbl)	115	65	64	73	84	98	106
Total Emissions (MT)	**248,325**	**81,604**	**48,100**	**55,259**	**63,605**	**74,305**	**80,474**
Previous Estimated Emissions (MT)	*250,643*	*187,872*	*220,021*	*278,638*	*330,049*	*396,275*	*NA*
Percent Change in Emissions	**-1%**	**-57%**	**-78%**	**-80%**	**-81%**	**-81%**	**NA**

NA (Not Applicable)

Equipment Counts (Fugitive Sources)

Additional reporting to EPA's GHGRP for Reporting Year (RY) 2015 improved EPA's allocation of GHGRP equipment counts between natural gas and petroleum for certain equipment leak category sources. EPA used the 2015 reporting data to develop improved counts of equipment per well. For more information, please see the *2017 Production Memo*. EPA developed per well counts of equipment using 2015 GHGRP data and applied those to national oil well counts for years 2011 through 2015. The per well counts for 1990 through 1992 were retained from previous Inventories, and counts for 1993 through 2010 were developed by linear interpolation. Overall, the change decreased calculated emissions over the time series by around 14 percent, with the largest changes in light crude separators. Stakeholder feedback on the public review draft of the Inventory and on the *2017 Production Memo* supported the use of updated GHGRP activity data. One stakeholder suggested that the approach of applying GHGRP average equipment counts to all wells in the United States may not appropriately characterize the production population that does not report to GHGRP, which may have higher or lower equipment counts per well. Data are currently unavailable to assess any differences between these populations. See Planned Improvements.

Table 3-43: National Equipment Counts for Fugitive Sources and National Emissions (Metric Tons CH_4)

Activity Data/Emissions	1990	2005	2011	2012	2013	2014	2015
Separators (Heavy Crude) (Counts)	12,561	18,224	21,288	22,218	22,872	23,567	23,105
Separators (Light Crude) (Counts)	114,315	165,859	193,744	202,202	208,154	214,484	210,281
Heater/Treaters (Light Crude) (Counts)	87,010	112,277	126,575	132,100	135,989	140,124	137,378
Headers (Heavy Crude) (Counts)	14,937	26,000	31,777	33,165	34,141	35,179	34,490
Headers (Light Crude) (Counts)	46,307	80,603	98,514	102,814	105,840	109,059	106,922
Total Emissions (MT)	**26,428**	**37,486**	**43,504**	**45,403**	**46,740**	**48,161**	**47,218**
Previous Estimated Emissions (MT)	*28,420*	*45,244*	*54,139*	*55,977*	*57,092*	*57,970*	*NA*
Percent Change in Emissions	**-7%**	**-17%**	**-20%**	**-19%**	**-18%**	**-17%**	**NA**

NA (Not Applicable)

Pneumatic Controllers and Chemical Injection Pumps

The changes to pneumatic controller and chemical injection pump equipment counts result from the changes in oil well counts described above and from the improved estimate of the counts of oil wells in EPA's GHGRP, which improved the activity factors of counts of controllers and pumps per oil well. The total per well counts of pneumatic controllers and pumps were updated using year 2015 GHGRP data. These per well counts were applied to years 2011 through 2015. For years 2011 through 2015, GHGRP year-specific data on fractions of pneumatic controllers in each category (high bleed "HB", low bleed "LB", and intermittent "IB") were applied to the counts of pneumatic controllers. The 1990 through 1992 per well counts of controllers in each category and pumps were retained for 1990 through 1992 and then the per-well counts of pneumatic controllers in each category for 1993 through 2010 were developed by linearly interpolating from 1992 through 2011. Category-specific emissions factors developed for the previous Inventory from year 2014 GHGRP activity data were applied throughout the time series. The recalculations resulted in large decreases in total national counts, but only minor changes in the annual fractions of controllers in each category. Overall, the change decreased calculated emissions over the time series by around 32 percent for pneumatic controllers, and 38 percent for chemical injection pumps.

Table 3-44: Pneumatic Controller and Chemical Injection Pump National Equipment Counts and National Emissions (Metric Tons CH_4)

Activity Data/Emissions	1990	2005	2011	2012	2013	2014	2015
Pneumatic Controllers							
High Bleed (Counts)	163,674	93,305	53,512	37,315	22,199	19,240	19,458
Low Bleed (Counts)	303,965	266,370	247,337	276,586	176,360	170,765	154,349
Intermittent Bleed (Counts)	0	151,502	240,801	251,394	383,375	409,626	414,074

Previous High Bleed (Counts)	*163,225*	*160,475*	*103,061*	*76,469*	*50,241*	*43,211*	*NA*
Previous Low Bleed (Counts)	*303,132*	*460,289*	*495,938*	*494,211*	*337,406*	*300,940*	*NA*
Previous Intermittent Bleed Counts	-	*284,053*	*533,112*	*599,859*	*806,207*	*868,079*	*NA*
Total Emissions (MT)	**764,189**	**683,107**	**643,177**	**593,342**	**713,734**	**740,188**	**745,330**
Previous Estimated Emissions (MT)	*762,095*	*1,211,263*	*1,348,290*	*1,334,230*	*1,511,099*	*1,569,471*	*NA*
Percent Change in Emissions	**0%**	**-44%**	**-52%**	**-56%**	**-53%**	**-53%**	**NA**
Chemical Injection Pumps							
Chemical Injection Pumps (Counts)	32,337	43,151	49,091	51,234	52,742	54,346	53,281
Previous Pumps (Counts)	*32,236*	*89,796*	*119,058*	*123,100*	*125,552*	*127,484*	*NA*
Total Emissions (MT)	**49,001**	**65,388**	**74,389**	**77,636**	**79,922**	**82,352**	**80,738**
Previous Estimated Emissions (MT)	*48,849*	*136,071*	*180,413*	*186,537*	*190,253*	*193,181*	*NA*
Percent Change in Emissions	**0%**	**-52%**	**-59%**	**-58%**	**-58%**	**-57%**	**NA**

NA (Not Applicable)

Associated Gas Venting and Flaring

EPA developed a new estimate for associated gas venting and flaring, replacing its previous estimates for stripper well venting. For more information, please see the *2017 Production Memo*. EPA developed a total percentage of oil wells that vent and flare from 2015 GHGRP data (12 percent), and applied that value to total national oil well counts for the full time series. EPA then applied the GHGRP year-specific split of that 12 percent between venting wells and flaring wells for years 2011 to 2015, and applied the 2011 split to each year from 1990 to 2011. Emission factors developed from year 2015 GHGRP data were applied for the full time series. EPA then removed the "stripper well" line item that had been included in previous inventories as those emissions are included in the updated estimates for associated gas venting and flaring. Stakeholder feedback on the public review draft of the Inventory and on the *2017 Production Memo* support the use of GHGRP data to calculate emissions from this source and one stakeholder suggested that annual updates to use GHGRP would be appropriate as this activity can vary significantly from year to year. Likewise, the stakeholder noted that past (e.g., 1990 through 2010) associated gas venting and flaring likely varied significantly from year to year and from region to region. Data are not presently available to take any year-to-year variation prior to 2011 into account. See Planned Improvements.

Table 3-45: Associated Gas Well Venting and Flaring National Emissions (Metric Tons CH_4)

Source	1990	2005	2011	2012	2013	2014	2015
Associated Gas Well Venting Emissions (MT)	608,758	511,701	574,851	482,816	214,665	89,333	42,518
Associated Gas Well Flaring Emissions (MT)	76,176	64,031	71,933	104,513	146,292	149,694	105,706
Previous Estimated Emissions from Stripper Wells (MT)	*16,353*	*14,491*	*14,651*	*14,799*	*14,799*	*14,799*	*NA*

NA (Not Applicable)

Gas STAR Reductions in Petroleum Systems Production Segment

In the previous Inventory, EPA included one-time and ongoing reductions reported to the Natural Gas STAR Program[163] grouped together as "Other" line items in the petroleum systems production segment. The reductions resulted in a 1 to 5 percent decrease from potential production segment emissions in years 1998 forward, and less

[163] See <https://www.epa.gov/natural-gas-star-program>.

than 1 percent decrease in emissions for earlier years. Year 2008 was most impacted by Gas STAR with a 5 percent decrease from potential emissions. Most of the reductions that year resulted from implementing artificial lift technologies that reduce well venting potential (one-time reductions; 56 percent of year total) and recovering casinghead gas (ongoing reduction; 40 percent of year total). These practices are generally reflected in the GHGRP data sets used to calculate emissions from associated gas venting/flaring. EPA has revised the methodology for these sources in the 2017 Inventory to take into account control practices in the EFs and calculate net emissions directly, therefore Gas STAR reductions are no longer taken into account in calculations. Stakeholder feedback on the public review draft of the Inventory and on the *2017 Production Memo* support using Gas STAR reductions data only where potential emissions are calculated, and removing them where they create potential double-counting of reductions. Table 3-46 below shows Gas STAR data used in the previous Inventory for the production segment, and the production emissions calculated using a net emissions approach in this Inventory.

Table 3-46: Production Segment Gas STAR Reductions Update (Metric Tons CH_4)

Source	1990	2005	2011	2012	2013	2014	2015
Production Emissions	**2,188,053**	**1,807,524**	**1,888,190**	**1,824,787**	**1,745,616**	**1,688,560**	**1,561,099**
Previous Production Potential Emissions	*1,519,486*	*1,957,071*	*2,262,521*	*2,346,709*	*2,586,398*	*2,725,082*	*NA*
Previous Production Gas STAR Reductions	*(154)*	*(35,774)*	*(44,872)*	*(45,013)*	*(30,856)*	*(30,856)*	*NA*
Previous Production Net Emissions	**1,519,332**	**1,921,298**	**2,217,649**	**2,301,696**	**2,555,542**	**2,694,227**	**NA**

NA (Not Applicable)
Note: Parentheses indicate negative values.

Transportation

Recalculations due to updated activity data for quantity of petroleum transported by barge or tanker in the transportation segment have resulted in an average increase in calculated emissions over the time series from this segment of less than 0.01 percent.

Refining

Recalculations due to updated data, including resubmitted GHGRP data, in the refining segment have resulted in an average increase in calculated emissions over the time series from this segment of less than 0.01 percent.

Planned Improvements

Plans for 2018 Inventory (1990 through 2016) and Future Inventories

CO_2 Data Update

In the current Inventory, EPA has held constant the CO_2 values from the previous Inventory as it assesses improvements to the CO_2 estimates. EPA is reviewing CO_2 data from EPA's GHGRP and considering updates that improve consistency of data sources and methods between the CH_4 emission estimates (which have been updated in recent years) and the CO_2 emission estimates in Petroleum Systems. EPA has conducted a preliminary assessment of the CO_2 data and will seek stakeholder feedback on the draft assessment and options for updates. Using GHGRP data to update CO_2 could result in an increase in the estimate of CO_2 from Petroleum Systems. The update could result in a shift in where CO_2 from flaring is estimated—currently, CO_2 from onshore production flaring for both Natural Gas and Petroleum Systems is included in Natural Gas Systems. GHGRP data would allow for an estimate for CO_2 specifically from associated gas flaring. The 2015 GHGRP reported total of CO_2 from associated gas venting and flaring is around 10 MMT CO_2. Scaling up to the national level using the same method as for CH_4 (based on oil well counts) would result in a significantly higher estimate. Similarly, scaling up tank-related CO_2 emissions to the national level using the same method as used for CH_4 calculations would result in a significant increase in emissions from that category.

Uncertainty

As noted in the Uncertainty discussion, the most recent uncertainty analysis for the petroleum systems emission estimates in the Inventory was conducted for the 1990 to 2009 Inventory that was released in 2011. Since the analysis was last conducted, several of the methods used in the Inventory have changed to reflect improved data and changes in industry practices and equipment. In addition, new studies and other data sources such as those discussed in the sections below offer improvement to understanding and quantifying the uncertainty of some emission source estimates. EPA is preparing a draft update to the uncertainty analysis conducted for the 2011 Inventory to reflect the new information and will seek stakeholder feedback on the draft analysis as part of the development of the next (i.e., 1990 through 2016) Inventory.

Abandoned Oil Wells

Abandoned wells are not currently included in the Inventory. EPA is seeking emission factors and national activity data available to calculate these emissions. Stakeholder comments supported including this source category in future Inventories, but noted that currently data are limited, and suggested reviewing data that will become available in the future. EPA has identified studies with data on abandoned wells (Townsend-Small et al. 2016; Kang et al. 2016; Brandt et al. 2014), and is considering including an estimate for this source in future Inventories. A preliminary estimate, based on the national emission estimate from Townsend-Small et al. (2016), the range of abandoned well counts in Townsend-Small et al. (2016) and Brandt et al. (2014), and the current split between oil and gas wells in the total producing wells population for 1990, is around 2.6 to 3.4 MMT CO_2 Eq. EPA seeks stakeholder feedback on abandoned wells.

Upcoming Data, and Additional Data that Could Inform the Inventory

EPA will continue to review data available from the GHGRP, in particular new data on hydraulically fractured oil well completions and workovers and new well-specific information, available in 2017 for the first time. EPA will consider revising its methods to take into account the new GHGRP data.

EPA will assess new data received by the Methane Challenge Program on an ongoing basis, which may be used to confirm or improve existing estimates and assumptions.

EPA continues to track studies that contain data that may be used to update the Inventory. EPA will also continue to assess studies that include and compare both top-down and bottom-up estimates, and which could lead to improved understanding of unassigned high emitters or "superemitters," (e.g., identification of emission sources and information on frequency of high emitters) as recommended in stakeholder comments.

EPA also continues to seek new data that could be used to assess or update the estimates in the Inventory. For example, stakeholder comments have highlighted areas where additional data that could inform the Inventory are currently limited or unavailable:

- Tank malfunction and control efficiency data. See Tanks in Recalculations Discussion.
- Activity data and emissions data for production facilities that do not report to GHGRP. See, for example, Equipment Counts in Recalculations Discussion.
- Associated gas venting and flaring data on practices from 1990 through 2010. See Associated Gas Venting and Flaring in Recalculations Discussion.
- Refineries emissions data. One stakeholder noted a recent study (Lavoie et al. 2017) that measured three refineries and found higher average emissions than in the Inventory, and the stakeholder suggested that EPA evaluate the study and any additional information available on this source.
- Abandoned well activity and emissions data. See above section in Planned Improvements.

EPA will continue to seek available data on these and other sources as part of the process to update the Inventory.

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 specific 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 emission estimates for geologic storage.

In the United States, facilities that produce CO_2 for various end-use applications (including capture facilities such as acid gas removal plants and ammonia plants), importers of CO_2, exporters of CO_2, facilities that conduct geologic sequestration of CO_2, and facilities that inject CO_2 underground, 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.

Currently available GHGRP data relevant for this inventory estimate consists of national-level annual quantities of CO_2 captured and extracted for EOR applications for 2010 to 2015. For 2015, data from EPA's GHGRP (Subpart PP) were unavailable for use in the current Inventory report due to data confidentiality reasons. A linear trend extrapolation was performed based on previous GHGRP reporting years (2010 through 2014) to estimate 2015 emissions. EPA will continue to evaluate the availability of additional GHGRP data and other opportunities for improving the emission estimates.

These estimates indicate that the amount of CO_2 captured and extracted from natural and industrial sites for EOR applications in 2015 is 61.0 MMT CO_2 Eq. (60,988 kt) (see Table 3-47 and Table 3-48). Site-specific monitoring and reporting data for CO_2 injection sites (i.e., EOR operations) were not readily available, therefore, the quantity of CO_2 captured and extracted is noted here for information purposes only; CO_2 captured and extracted from industrial and commercial processes is assumed to be emitted and included in emissions totals from those processes.

Table 3-47: Quantity of CO_2 Captured and Extracted for EOR Operations (MMT CO_2)

Stage	1990	2005	2011	2012	2013	2014	2015
Capture Facilities	4.8	6.5	9.9	9.3	12.2	13.1	13.5
Extraction Facilities	20.8	28.3	48.4	48.9	47.0	46.2	47.5
Total	**25.6**	**34.7**	**58.2**	**58.1**	**59.2**	**59.3**	**61.0**

Note: Totals may not sum due to independent rounding.

Table 3-48: Quantity of CO_2 Captured and Extracted for EOR Operations (kt)

Stage	1990	2005	2011	2012	2013	2014	2015
Capture Facilities	4,832	6,475	9,877	9,267	12,205	13,093	13,483
Extraction Facilities	20,811	28,267	48,370	48,869	46,984	46,225	47,505
Total	**25,643**	**34,742**	**58,247**	**58,136**	**59,189**	**59,318**	**60,988**

Note: 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 162.4 MMT CO_2 Eq. (6,497 kt) of CH_4 in 2015, a 16 percent decrease compared to 1990 emissions, and a 0.1 percent decrease compared to 2014 emissions (see Table 3-49, Table 3-50, and Table 3-51) and 42.4 MMT CO_2 Eq. (42,351 kt) of non-combustion CO_2 in 2015, a 12 percent increase compared to 1990 emissions.

The 1990 to 2015 trend in CH_4 is not consistent across segments. Overall, the 1990 to 2015 decrease in CH_4 emissions is due primarily to the decrease in emissions from distribution (75 percent decrease), transmission and storage (42 percent decrease), and processing (48 percent decrease) segments. Over the same time period, the production segments saw increased methane emissions of 51 percent. Natural gas systems also emitted 42.4 MMT CO_2 Eq. (42,351 kt) of non-combustion CO_2 in 2015, a 12 percent increase compared to 1990 emissions. The 1990 to 2015 increase in CO_2 is due primarily to flaring; the volume of gas flared increased 93 percent from 1990.

Methane 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.

Production (including gathering and boosting). In the production stage, wells are used to withdraw raw gas from underground formations. Emissions arise from the wells themselves, and well-site gas treatment equipment such as dehydrators and separators. Gathering and boosting emission sources are not reported under a unique segment, but are included within the production sector. The gathering and boosting sources include gathering and boosting stations (with multiple emission sources on site) and gathering pipelines. The gathering and boosting stations receive natural gas from production sites and transfer it, via gathering pipelines, to transmission pipelines or processing facilities (custody transfer points are typically used to segregate sources between each segment). Emissions from production (including gathering and boosting) account for 66 percent of CH_4 emissions and 44 percent of non-combustion CO_2 emissions from natural gas systems in 2015. Emissions from gathering stations, pneumatic controllers, liquids unloading, and offshore platforms account for most of the CH_4 emissions in 2015. Flaring emissions account for most of the non-combustion CO_2 emissions. Due to the aggregated activity data source for CO_2 from flaring, it is not possible to develop separate estimates for flaring occurring in natural gas production and flaring occurring in oil production. Total CO_2 emissions from flaring (onshore and offshore) for both natural gas and oil were 18.0 MMT CO_2 in 2015 and are included in the Natural Gas Systems estimates. Methane emissions from production increased by 51 percent from 1990 to 2015, due primarily to increases in emissions from gathering and boosting stations (driven by an increase in the number of stations), increases in emissions from pneumatic controllers (due to an increase in the number of controllers, particularly in the number of intermittent bleed controllers), and chemical injection pumps (due to an increase in the number of pumps). Carbon dioxide emissions from production increased 88 percent from 1990 to 2015 due primarily to increases in 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. Most of the non-combustion CO_2 emissions come from acid gas removal (AGR) units, which are designed to remove CO_2 from natural gas. Processing plants account for 7 percent of CH_4 emissions and 56 percent of non-combustion CO_2 emissions from natural gas systems. Methane emissions from processing decreased by 48 percent from 1990 to 2015 as emissions from compressors (leaks and venting) and equipment leaks decreased. Carbon dioxide emissions from processing decreased by 15 percent from 1990 to 2015, due to 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 are used to move the gas throughout the U.S. transmission system. Fugitive CH_4 emissions from these compressor stations, and venting from pneumatic controllers account for most of the emissions from this stage. Uncombusted engine exhaust and pipeline venting are also sources of CH_4 emissions from transmission. 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). In 2015, emissions from the Aliso Canyon leak event in Southern California contributed 2.0 MMT CO_2 Eq. to transmission and storage emissions, around 5 percent of total emissions for this segment. Compressors and dehydrators are the primary contributors to emissions from storage. Methane emissions from the transmission and storage sector account for approximately 21 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 42 percent from 1990 to 2015 due to reduced compressor station emissions (including emissions from compressors and fugitives). CO_2 emissions from transmission and storage have decreased by 37 percent from 1990 to 2015, also due to reduced compressor station emissions.

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 1,274,976 miles of distribution mains in 2015, an increase of over 330,000 miles since 1990 (PHMSA 2016a; PHMSA 2016b). Distribution system emissions, which account for 7 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, as have station upgrades at metering and regulating (M&R) stations. Distribution system CH_4 emissions in 2015 were 75 percent lower than 1990 levels (changed from 43.5 MMT CO_2 Eq. to 11.0 MMT CO_2 Eq.), while distribution CO_2 emissions in 2015 were 72 percent lower than 1990 levels (CO_2 emission from this segment are less than 0.1 MMT CO_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 3-49) and kt (Table 3-50). Table 3-51 provides additional information on how the estimates in Table 3-47 were calculated. Table 3-51 shows the calculated potential 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 net 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 3-49: CH_4 Emissions from Natural Gas Systems (MMT CO_2 Eq.)[a]

Stage	1990	2005	2011	2012	2013	2014	2015
Field Production	70.6	95.2	104.5	106.9	106.3	108.2	106.6
Processing	21.3	11.7	10.1	10.1	10.9	11.1	11.1
Transmission and Storage	58.6	30.7	28.8	27.9	30.8	32.0	33.7
Distribution	43.5	22.1	11.1	11.3	11.2	11.2	11.0
Total	**194.1**	**159.7**	**154.5**	**156.2**	**159.2**	**162.5**	**162.4**

[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 3-50: CH_4 Emissions from Natural Gas Systems (kt)[a]

Stage	1990	2005	2011	2012	2013	2014	2015
Field Production	2,826	3,808	4,178	4,274	4,253	4,327	4,264
Processing	853	466	405	406	434	446	445
Transmission and Storage	2,343	1,230	1,152	1,116	1,232	1,282	1,349
Distribution	1,741	884	444	451	449	446	439
Total	**7,762**	**6,387**	**6,180**	**6,247**	**6,368**	**6,501**	**6,497**

[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 3-51: Calculated Potential CH_4 and Captured/Combusted CH_4 from Natural Gas Systems (MMT CO_2 Eq.)

	1990	2005	2011	2012	2013	2014	2015
Calculated Potential[a]	**194.1**	**179.1**	**172.4**	**174.5**	**176.6**	**180.5**	**181.1**
Field Production	70.6	101.0	112.4	114.7	114.4	116.7	115.8
Processing	21.3	11.7	10.1	10.1	10.9	11.1	11.1
Transmission and Storage	58.6	43.1	37.3	37.3	39.1	40.4	42.2
Distribution	43.5	23.3	12.6	12.4	12.2	12.2	12.0
Captured/Combusted	**0.0**	**19.4**	**17.9**	**18.3**	**17.4**	**18.0**	**18.6**
Field Production	0.0	5.8	7.9	7.8	8.1	8.6	9.2
Processing	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Transmission and Storage	0.0	12.4	8.5	9.4	8.3	8.4	8.5
Distribution	0.0	1.2	1.5	1.1	1.0	1.0	1.0
Net Emissions	**194.1**	**159.7**	**154.5**	**156.2**	**159.2**	**162.5**	**162.4**
Field Production	70.6	95.2	104.5	106.9	106.3	108.2	106.6
Processing	21.3	11.7	10.1	10.1	10.9	11.1	11.1
Transmission and Storage	58.6	30.7	28.8	27.9	30.8	32.0	33.7
Distribution	43.5	22.1	11.1	11.3	11.2	11.2	11.0

[a] In this context, "potential" means the total emissions calculated before voluntary reductions and regulatory controls are applied.
Note: Totals may not sum due to independent rounding.

Table 3-52: Non-combustion CO_2 Emissions from Natural Gas Systems (MMT)

Stage	1990	2005	2011	2012	2013	2014	2015
Field Production	9.9	8.3	14.1	13.7	16.6	18.6	18.6
Processing	27.8	21.7	21.5	21.5	21.8	23.7	23.7
Transmission and Storage	0.1	+	+	+	+	+	+
Distribution	0.1	+	+	+	+	+	+
Total	**37.7**	**30.1**	**35.7**	**35.2**	**38.5**	**42.4**	**42.4**

+ Does not exceed 0.1 MMT CO_2 Eq.
Note: Totals may not sum due to independent rounding.

Table 3-53: Non-combustion CO_2 Emissions from Natural Gas Systems (kt)

Stage	1990	2005	2011	2012	2013	2014	2015
Field Production	9,857	8,260	14,146	13,684	16,649	18,585	18,585
Processing	27,763	21,746	21,466	21,469	21,756	23,713	23,713
Transmission and Storage	62	43	36	35	37	39	39
Distribution	50	27	15	14	14	14	14
Total	**37,732**	**30,076**	**35,662**	**35,203**	**38,457**	**42,351**	**42,351**

Note: Totals may not sum due to independent rounding.

Methodology

The methodology for natural gas emission estimates presented in this public review draft of the 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 segment.

The approach for calculating emissions for natural gas systems generally involves the application of emission factors to activity data. For many sources, the approach uses technology-specific emission factors or emission factors that vary over time and take into account changes to technologies and practices, which are used to calculate net

emissions directly. For others, the approach uses what are considered "potential methane factors" and reduction data to calculate net emissions.

Emission Factors. Key references for emission factors for CH_4 and non-combustion-related CO_2 emissions from the U.S. natural gas industry include the Gas Research Institute (GRI) and EPA (EPA/GRI 1996), the Greenhouse Gas Reporting Program (GHGRP), and others.

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 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.

GHGRP Subpart W data were used to develop emission factors for several sources in the Inventory. In the production segment, GHGRP data were used to develop emission factors for gas well completions and workovers (refracturing) with hydraulic fracturing, pneumatic controllers and chemical injection pumps, condensate tanks, and liquids unloading. In the processing segment, for recent years of the times series, GHGRP data were used to develop emission factors for fugitives, compressors, flares, dehydrators, and blowdowns/venting. In the transmission and storage segment, for recent years of the times series, GHGRP data were used to develop factors for pneumatic controllers.

Other data sources used for emission factors include Marchese et al. for gathering stations, Zimmerle et al. for transmission and storage station fugitives and compressors, and Lamb et al. for recent years for distribution pipelines and meter/regulator stations.

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.

Activity Data. Activity data were taken from various published data sets, as detailed in Annex 3.6. Key activity data sources include data sets developed and maintained by DrillingInfo, Inc.; U.S. Department of the Interior's Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE, previously Minerals and Management Service); U.S. Department of Energy's Energy Information Administration (EIA) and Federal Energy Regulatory Commission (FERC); the Natural Gas STAR Program annual emissions savings data; Oil and Gas Journal; U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration; EPA's Greenhouse Gas Reporting Program; the Wyoming Conservation Commission; and the Alabama State Oil and Gas Board.

For a few sources, recent direct activity data are not available. For these sources, either 2014 data was used as a proxy for 2015 data, or a set of industry activity data drivers was developed and used to calculate activity data over the time series. 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. More information on activity data and drivers is available in Annex 3.6.

A complete list of references for emission factors and activity data by emission source is provided in Annex 3.6.

Calculating Net Emissions. For most sources, emissions are calculated directly by applying emission factors to activity data. However, for certain sectors, some sources are calculated using potential emission factors, and the step of deducting CH_4 that is not emitted from the total CH_4 potential estimates to develop net CH_4 emissions is applied. To take into account use of such technologies and practices that result in lower emissions, data are collected on both regulatory and voluntary reductions. Regulatory actions addressed using this method include National Emission Standards for Hazardous Air Pollutants (NESHAP) regulations for dehydrator vents. Voluntary reductions included in the Inventory are those reported to Natural Gas STAR.

In the current Inventory, EPA has held constant the CO_2 values from the previous Inventory (developed using the methodology as described in this section) as it assesses improvements to the CO_2 estimates. See Planned Improvements.

In fall of 2015, a well in a California storage field began leaking methane at an initial average rate of around 50 metric tons (MT) of methane (CH_4) an hour, and continued leaking until it was permanently sealed in February of 2016.[164] An emission estimate from the leak event was included for 2015, using the estimate of the leak published by the California Air Resources Board (99,650 MT for the duration of the leak), adjusted to only include those emissions that occurred in 2015 (2016 emissions will be included in the next Inventory). The 2015 emission estimate of 78,350 MT CH_4 was added to the 2015 estimate of fugitive emissions from storage wells, calculated with an emission factor approach, resulting in total emissions from storage wells in 2015 of 92,590 MT CH_4. For more information, please see *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2015: Update for Storage Segment Emissions*.[165]

Uncertainty and Time-Series Consistency

The most recent uncertainty analysis for the natural gas and petroleum systems emission estimates in the Inventory was conducted for the 1990 to 2009 Inventory report that was released in 2011 and has not yet been updated. Since the analysis was last conducted, several of the methods used in the Inventory have changed to reflect improved data and changes in industry practices and equipment. In addition, new studies (e.g., Lamb, et al. 2015; Lyon, et al. 2015; Marchese, et al. 2015; Zimmerle, et al. 2015) and other data sources such as those discussed in the sections below offer improvement to understanding and quantifying the uncertainty of some emission source estimates. EPA is preparing a draft update to the uncertainty analysis conducted for the 2011 Inventory to reflect the new information and will seek stakeholder feedback on the draft analysis as part of the development of the next (i.e., 1990 through 2016) Inventory. For more information, please see the Planned Improvements section.

To develop the values in Table 3-54 below, EPA has applied the uncertainty percentage ranges calculated previously to the updated 2015 emission estimates. To develop the uncertainty percentage ranges, EPA used 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 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 emission estimates for this category evolves and improves as the underlying methodologies and datasets improve.

Given the recent revisions, the uncertainty ranges applied may not reflect the uncertainty associated with the recently revised emission factors and activity data sources.

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 2015, based on the previously conducted uncertainty assessment using the recommended IPCC methodology. The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-54. Natural gas systems CH_4 emissions in 2015 were estimated to be between 131.6 and 211.2 MMT CO_2 Eq. at a 95 percent confidence level, based on previously calculated uncertainty. Natural gas systems non-energy CO_2 emissions in 2014 were estimated to be between 34.3 and 55.1 MMT CO_2 Eq. at a 95 percent confidence level.

Table 3-54: 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	2015 Emission Estimate (MMT CO_2 Eq.)[b]	Uncertainty Range Relative to Emission Estimate[a] (MMT CO_2 Eq.)	(%)

[164] For more information on the Aliso Canyon event, and the measurements conducted of the leak, please see Ensuring Safe and Reliable Underground Natural Gas Storage, *Final Report of the Interagency Task Force on Natural Gas Storage Safety*, available at <http://www.energy.gov/sites/prod/files/2016/10/f33/Ensuring%20Safe%20and%20Reliable%20Underground%20Natural%20Gas%20Storage%20-%20Final%20Report.pdf>.

[165] <https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems-ghg-inventory-additional-information-1990-2015-ghg>.

			Lower Bound[b]	Upper Bound[b]	Lower Bound[b]	Upper Bound[b]
Natural Gas Systems	CH_4	162.4	131.6	211.2	-19%	+30%
Natural Gas Systems[c]	CO_2	42.4	34.3	55.1	-19%	+30%

[a] Range of emission estimates estimated by applying the 95 percent confidence intervals obtained from the Monte Carlo Simulation analysis conducted for the year 2009.
[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 3-49 and Table 3-50.
[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

To develop a consistent time series for 1990 through 2015, for sources with new data, EPA reviewed available information on factors that may have resulted in changes over the time series (e.g., regulations, voluntary actions) and requested stakeholder feedback on trends as well. For most sources, EPA developed annual data for 1993-2010 by interpolating activity data or emission factors or both between 1992 and 2011 data points.

Information on time-series consistency for sources updated in this public review draft can be found in the Recalculation Discussion below, with additional detail provided in the 2017 Production and Processing memos. For detailed information, please see Annex 3.5.

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. The EPA has a multi-step data verification process for GHGRP data, including automatic checks during data-entry, statistical analyses on completed reports, and staff review of the reported data. Based on the results of the verification process, the EPA follows up with facilities to resolve mistakes that may have occurred.[166]

As in previous years, EPA conducted early engagement and communication with stakeholders on updates prior to public review. In December 2016 and January 2017, EPA held stakeholder webinars on greenhouse gas data for oil and gas. In early 2017, EPA released memos detailing updates under consideration and requesting stakeholder feedback. In February 2017, EPA released a public review draft of the Inventory. Stakeholder feedback received through these processes is discussed in the Recalculations Discussion and Planned Improvements sections below.

In recent years, several studies have measured emissions at the source level and at the national or regional level and calculated emission estimates that may differ from the Inventory. 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, and studies that use tools such as inverse modeling to estimate the level of overall emissions needed to account for measured atmospheric concentrations of greenhouse gases at various scales. The first type of study can lead to direct improvements to or verification of Inventory estimates. In the past few years, EPA has reviewed and in many cases, incorporated data from these data sources. The second type of study can provide general indications on potential over- and under-estimates.

A key challenge in using these types of studies to assess Inventory results is having a relevant basis for comparison (i.e., the independent study should assess data from the Inventory and not another data set, such as EDGAR.). In an effort to improve the ability to compare the national-level inventory with measurement results that may be at other scales, a team at Harvard University along with EPA and other coauthors developed a gridded inventory of U.S.

[166] See <https://www.epa.gov/sites/production/files/2015-07/documents/ghgrp_verification_factsheet.pdf>.

anthropogenic methane emissions with 0.1° x 0.1° spatial resolution, monthly temporal resolution, and detailed scale-dependent error characterization.[167] The gridded methane inventory is designed to be consistent with the 2016 *Inventory of U.S. Greenhouse Gas Emissions and Sinks (1990-2014)* estimates for the year 2012, which presents national totals for different source types.[168]

Recalculations Discussion

The EPA received information and data related to the emission estimates through GHGRP reporting, the annual Inventory formal public notice periods, stakeholder feedback on updates under consideration, and new studies. In January 2017, the EPA released draft memoranda that discussed the changes under consideration and requested stakeholder feedback on those changes.[169]

The EPA thoroughly evaluated relevant information available, and made several updates in the Inventory, including revisions to production segment activity and emissions data, gathering and boosting facility emissions, and processing segment activity and emissions data.

The impact of all revisions to natural gas systems CH_4 estimates is a decrease of 13.6 MMT CO_2 Eq., or 8 percent, comparing the 2014 value from the previous Inventory to the 2014 value in this Inventory. Over the time series, the average change is a decrease of 17.0 MMT CO_2 Eq., or 9 percent.

In the current Inventory, EPA has held constant the CO_2 values from the previous (i.e., 1990 through 2014) Inventory (developed using the methodology as described in this section) as it assesses improvements to the CO_2 estimates. See Planned Improvements.

Production

This section references the Inventory production segment supporting memoranda: "Revisions to Natural Gas and Petroleum Production Emissions," (the *2017 Production Memo*).[170] This memorandum contains further details and documentation of recalculations.

Overall, Recalculations for the production segment (including gathering and boosting facilities) resulted in a small decrease in the 2014 CH_4 emission estimate, from 109.0 MMT CO_2 Eq. in the previous Inventory, to 108.2 MMT CO_2 Eq. in this Inventory, or 1 percent. Over the time series, the average change is a decrease of 11 MMT CO_2 Eq., or 11 percent.

Tanks

EPA developed emission estimates for condensate tanks using GHGRP data and a throughput-based approach. For more information, please see the *2017 Production Memo*. Using 2015 GHGRP data, EPA developed a value for the fraction of condensate produced (MMbbl) sent to tanks (79.4 percent), the split between large tanks (77.1 percent) and small tanks (22.9 percent), and the fraction of condensate sent to large and small tanks that is in each tank control category. For large tanks, for 2015, 69.0 percent of condensate is sent to tanks with flares, 13.4 percent is sent to tanks with VRU, and 17.6 percent is sent to uncontrolled large tanks. For small tanks, 33.5 percent of condensate goes to small tanks with flares, and 66.6 percent goes to small tanks without flares. To develop the time series, the fraction of condensate production sent to tanks (79.4 percent) was held constant throughout the 1990 to 2015 time series. The percentages of condensate production sent to tanks that was sent to large tanks (77.1 percent)

[167] See <https://www.epa.gov/ghgemissions/gridded-2012-methane-emissions>.

[168] See <https://www.epa.gov/ghgemissions/us-greenhouse-gas-inventory-report-1990-2014>.

[169] See *Revisions under Consideration for Natural Gas and Petroleum Systems Production Emissions*, and *Revisions under Consideration for Natural Gas Systems Processing Segment Emissions*, available at <https://www.epa.gov/ghgemissions/updates-under-consideration-petroleum-and-natural-gas-systems-1990-2015-ghg-inventory>.

[170] See <https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems-ghg-inventory-additional-information-1990-2015-ghg>.

and small tanks (22.9 percent) were also held constant throughout the 1990 to2015 time series. The 2015 fraction of throughput in each 2015 control category was applied to for the years 2011 to 2015. For large tanks, it was assumed that in 1990, 50 percent of condensate to large tanks went to tanks without controls, 50 percent went to tanks with flares, and that 0 percent went to tanks with VRUs. The previous Inventory applied an assumption that 50 percent of condensate went to uncontrolled tanks and 50 percent to controlled tanks (VRU or flares). For small tanks, it was assumed that in 1990 all throughput was sent to tanks in the uncontrolled category. This assumption was applied because of the relatively limited use of controls at small tanks in the 2015 GHGRP data. For both large and small tanks, EPA linearly interpolated from 1990 to 2011 for each control category. Category-specific emission factors developed from 2015 GHGRP data were applied for every year of the time series. EPA also developed an emission factor for malfunctioning dump values. In EPA's GHGRP, only large tanks report malfunctioning dump valves. EPA has applied the emission factor to all throughput in the large tank categories for each year of the time series. Stakeholder feedback on the public review draft of the Inventory and on the *2017 Production Memo* support the use of GHGRP data to calculate tank emissions and in particular the throughput approach, but recommended enhanced screening of GHGRP data. One stakeholder suggested that the tanks estimate underestimates tank emissions: the stakeholder suggested that the emission data and control efficiencies reported to EPA's GHGRP for this source may be inaccurate and that the methods and data do not take into account the full volume of emissions from stuck dump valves and other malfunctions. Another stakeholder expressed that aerial survey observations should not be presumed to indicate an underestimation of tank emissions in GHGRP. Data are currently unavailable to assess malfunctions, to assess the Inventory data on stuck dump valves, or to use aerial observations to inform Inventory estimates for this sources. See Planned Improvements.

The overall impact of the change is a decrease in calculated emissions of 86 percent on average over the time series.

Table 3-55: National Tank Activity Data (MMbbl) by Category and National Emissions (Metric Tons CH_4)

Activity Data/Emissions	1990	2005	2011	2012	2013	2014	2015
Large Tanks w/ Flares (MMbbl)	34	44	80	99	118	124	126
Large Tanks w/ VRU (MMbbl)	-	7	16	19	23	24	24
Large Tanks w/o Control (MMbbl)	34	18	20	25	30	32	32
Small Tanks w/ Flares (MMbbl)	-	5	12	14	17	18	18
Small Tanks w/o Flares (MMbbl)	20	15	23	28	34	35	36
Total Emissions (MT)	**15,707**	**10,819**	**15,037**	**18,440**	**22,160**	**23,189**	**23,506**
Previous Potential Emissions (MT)	*93,224*	*119,191*	*229,284*	*259,121*	*312,185*	*303,711*	*NA*
Previous Regulatory Reductions (MT)	-	*31,908*	*61,381*	*69,369*	*83,575*	*81,306*	*NA*
Previous Net Emissions (MT)	***93,224***	***87,283***	***167,902***	***189,752***	***228,610***	***222,405***	***NA***
Percent Change in Emissions	**-83%**	**-88%**	**-91%**	**-90%**	**-90%**	**-90%**	**NA**

NA (Not Applicable)

Well Counts

EPA has used a more recent version and improved data processing of the DrillingInfo data set to update well counts data in the Inventory. For more information, see the *2017 Production Memo*. This update, which addressed a double-counting issue in last year's data set, resulted in a decrease of 6 percent in gas well counts on average over the time series. Stakeholder feedback on the public review draft of the Inventory and on the *2017 Production Memo* support the update to well counts data as it improves consistency with other recently published sources of well count data.

Table 3-56: Gas Well Count Data

Gas Well Count	1990	2005	2011	2012	2013	2014	2015
Number of Gas Wells	202,628	355,234	440,371	438,672	431,926	433,941	421,893
Previous Estimated Number of Gas Wells	*218,709*	*373,903*	*463,198*	*460,588*	*454,491*	*456,140*	*NA*
Percent Change	**-7%**	**-5%**	**-5%**	**-5%**	**-5%**	**-5%**	**NA**

NA (Not Applicable)

Equipment Counts (Fugitive Sources)

Additional reporting to GHGRP for Reporting Year (RY) 2015 improved EPA's allocation of GHGRP equipment counts between natural gas and petroleum for certain equipment leak category sources. EPA used the 2015 reporting data to develop improved counts of equipment per well. For more information, please see the *2017 Production Memo*. EPA developed per well counts of equipment using 2015 GHGRP data and applied those to national gas well counts for years 2011 through 2015. The per well counts for 1990 through 1992 were retained from previous Inventories, and counts for 1993 through 2010 were developed by linear interpolation. Overall, the change decreased calculated emissions over the time series by around 13 percent, with the largest decreases in meters/piping (20 percent) and compressors (21 percent), and dehydrators (19 percent). Stakeholder feedback on the public review draft of the Inventory and on the *2017 Production Memo* support the use of updated GHGRP activity data. One stakeholder highlighted a discrepancy in well count data reported under different categories in GHGRP. EPA will update next year's Inventory with resubmitted data, which may result in minor changes in equipment counts per well for 2015. One stakeholder suggested that the approach of applying GHGRP average equipment counts to all wells in the United States may not appropriately characterize the production population that does not report to EPA's GHGRP, which may have higher or lower equipment counts per well. Data are currently unavailable to assess any differences between these populations. See Planned Improvements.

Table 3-57: National Equipment Counts for Fugitive Sources and National Emissions (Metric Tons CH_4)

Activity Data/Emissions	1990	2005	2011	2012	2013	2014	2015
Separators (Counts)	119,216	235,387	301,706	300,542	295,920	297,301	289,046
Heaters (Counts)	48,573	75,389	90,901	90,551	89,158	89,574	87,087
Dehydrators (Counts)	28,250	19,486	11,727	11,682	11,502	11,556	11,235
Meters/Piping (Counts)	182,647	305,242	377,597	376,141	370,356	372,084	361,753
Compressors (Counts)	17,575	28,423	34,473	34,340	33,812	33,969	33,026
Total Emissions (MT)	**138,777**	**248,898**	**300,327**	**299,137**	**293,315**	**291,617**	**286,872**
Previous Estimated Emissions (MT)	*153,106*	*292,944*	*364,342*	*362,341*	*356,470*	*354,306*	*NA*
Percent Change in Emissions	**-9%**	**-15%**	**-18%**	**-17%**	**-18%**	**-18%**	**NA**

NA (Not Applicable)

Pneumatic Controllers and Chemical Injection Pumps

The changes to pneumatic controller and chemical injection pump equipment counts result from the changes in gas well counts described above and from the improved estimate of the counts of gas wells in GHGRP, which improved the activity factors of counts of controllers and pumps per gas well. Total per well counts of pneumatic controllers and chemical injection pump were updated using year 2015 GHGRP data. These per well counts were applied to years 2011 through 2015. For years 2011 through 2015, GHGRP year-specific data on fractions of pneumatic controllers in each category (high bleed "HB", low bleed "LB", and intermittent "IB") were applied to the counts of pneumatic controllers. The 1990 through 1992 per well counts of controllers in each category and pumps were retained for 1990 through 1992 and then the per-well counts of pneumatic controllers in each category and pumps for 1993 through 2010 were developed by linear interpolating from 1992 through 2011. Category-specific emissions factors developed from year 2014 GHGRP data were applied throughout the time series. The recalculations using the latest GHGRP activity data resulted in only minor changes in the annual fractions of controllers in each category, and small decreases in total calculated emissions.

Table 3-58: Pneumatic Controller and Chemical Injection Pump National Equipment Counts and National Emissions (Metric Tons CH_4)

Activity Data/Emissions	1990	2005	2011	2012	2013	2014	2015
Pneumatic Controllers							
Low Bleed (Counts)	NA	144,046	289,638	247,684	165,646	197,081	188,740
High Bleed (Counts)	72,538	101,476	79,769	68,479	39,218	28,956	21,672

Intermittent Bleed (Counts)	134,713	343,087	459,066	509,114	607,722	590,340	583,298
Previous Low Bleed (Counts)	*-*	*138,223*	*276,586*	*239,734*	*144,443*	*226,280*	*NA*
Previous High Bleed (Counts)	*80,776*	*106,689*	*86,310*	*76,418*	*42,050*	*29,006*	*NA*
Previous Intermittent Bleed (Counts)	*150,013*	*360,379*	*484,942*	*526,908*	*645,408*	*579,633*	*NA*
Total Emissions (MT)	**523,787**	**993,203**	**1,099,713**	**1,120,439**	**1,130,709**	**1,064,230**	**1,020,246**
Previous Estimated Emissions	*556,347*	*1,079,256*	*1,229,714*	*1,245,311*	*1,259,753*	*1,105,119*	*NA*
Percent Change	**-6%**	**-8%**	**-11%**	**-10%**	**-10%**	**-4%**	**NA**
Chemical Injection Pumps							
Chemical Injection Pumps (Counts)	15,904	57,115	83,301	82,980	81,704	82,085	79,806
Previous Chemical Injection Pumps (Counts)	*17,805*	*58,094*	*84,538*	*84,061*	*82,948*	*83,249*	*NA*
Total Emissions (MT)	**27,727**	**90,889**	**126,715**	**126,226**	**124,285**	**124,864**	**121,398**
Previous Estimated Emissions	*29,207*	*96,006*	*131,488*	*130,624*	*128,687*	*128,876*	*NA*
Percent Change in Emissions	**5%**	**-5%**	**-4%**	**-3%**	**-3%**	**-3%**	**NA**

NA (Not Applicable)

Liquids Unloading

EPA updated its estimates for liquids unloading to use data from GHGRP. For more information, please see the *2017 Production Memo*. To develop this estimate, EPA retained the assumption from the previous Inventory that 56 percent of all gas wells conduct liquids unloading (total percent of wells that vent for liquids unloading and wells that do not vent for liquids unloading (i.e., use of non-emitting systems)) over the time series (developed from API/ANGA 2012). EPA also retained the assumption that in 1990, all of the 56 percent of wells with liquids unloading issues vent without plunger lifts. For the years 2011 to 2015, EPA applied the 2015 GHGRP fraction of gas wells that vent for liquids unloading (16.8 percent), and applied year-specific fractions of wells venting with plunger lifts and wells venting without plunger lifts. For years 1991 to 2010, EPA interpolated from the percentages of wells in each category for 1990 to 2011. For all years of the time series, EPA applied average EFs calculated from 2011 to 2015 GHGRP data. The activity data assumptions and emission factors were developed and applied at the national level, whereas the previous year's Inventory calculated emissions with regional factors. Stakeholder feedback on the public review draft of the Inventory and on the *2017 Production Memo* support the use of GHGRP data to update this category, but suggested that the method be applied at the regional level. See Planned Improvements.

The recalculation for liquids unloading emissions resulted in an average decrease of 344,374 MT or 48 percent over the time series. The decrease in calculated emissions is much smaller in recent years (e.g., 16 percent for 2010 through 2014), than earlier years of the time series (e.g., 57 percent for 1990 through 1995).

Table 3-59: National Liquids Unloading Activity Data by Category and National Emissions (Metric Tons CH_4)

Activity Data/Emissions	1990	2005	2011	2012	2013	2014	2015
Wells Venting w/o Plunger Lifts (Counts)	113,978	73,436	28,366	31,309	34,265	33,646	28,634
Emissions (w/o Plunger) (MT)	352,138	226,881	87,638	96,729	105,862	103,951	88,464
Wells Venting With Plunger Lifts (Counts)	-	26,237	45,535	42,307	38,219	39,176	42,166
Emissions (w/ Plunger) (MT)	-	75,085	130,313	121,076	109,376	112,114	120,673

Total Emissions (MT)	**352,138**	**301,966**	**217,951**	**217,805**	**215,238**	**216,065**	**209,138**
Previous Estimated Emissions (MT)	*805,883*	*706,101*	*266,613*	*265,142*	*260,497*	*260,644*	*NA*
Percent Change in Emissions	**-56%**	**-57%**	**-18%**	**-18%**	**-17%**	**-17%**	**NA**

NA (Not Applicable)

Gathering and Boosting Episodic Emissions

EPA applied a factor developed in the Marchese study (37 metric tons CH_4 per station) to calculate emissions from gathering and boosting station episodic events, a source which was removed from the Inventory with last year's update to use GHGRP data (which only included production sites) for most categories, and Marchese et al. for gathering stations. To include an estimate for this source consistent with the estimate for gathering stations, EPA added information from the Marchese study. For more information, please see the *2017 Production Memo*. This value was applied to all stations for each year of the time series. Stakeholder feedback on the public review draft of the Inventory and on the *2017 Production Memo* support the use of future GHGRP data on gathering systems instead of the Marchese study data, and not including the estimate in this year's Inventory. See Planned Improvements.

Table 3-60: National Gathering and Boosting Episodic Emission Activity Data (Number of Stations) and National Emissions (Metric Tons CH_4)

Activity Data/Emissions	**1990**	**2005**	**2011**	**2012**	**2013**	**2014**	**2015**
Gathering Stations (counts)	2,565	2,968	4,246	4,549	4,638	5,034	5,276
Total Emissions (MT)	**94,905**	**109,816**	**157,102**	**168,313**	**171,606**	**186,258**	**195,212**
Previous Estimated Emissions	*NA*	*NA*	*NA*	*NA*	*NA*	*NA*	*NA*
Percent Change in Emissions	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**

NA (Not Applicable)

Gas STAR Reductions

The production segment estimates include several sources that are calculated with potential emissions approaches, and therefore Gas STAR reductions are subtracted from the production segment estimates. Many of the activities reported to Gas STAR in the production segment are cross-cutting and apply to more than one emissions source and therefore cannot be assigned to one emissions source, but instead are included in an "other reductions" category. As many sources in production are now calculated with net factor approaches, to address potential double-counting of reductions, a scaling factor is applied to the "other reductions" to reduce this reported amount based an estimate of the fraction of those reductions that occur in the sources that are now calculated using net emissions approaches. This fraction was developed by dividing the net emissions from sources with net approaches, by the total calculated (non-gathering) production segment emissions (without deducting the Gas STAR reductions).

The fractions were recalculated this year to take into account that tanks are now calculated with net emissions approaches, and to address two minor errors in the previous calculation: 1). gas engine emissions, gathering pipeline emissions, and compressor start emissions were incorrectly included in the "potential emission" sources even though they have corresponding source-specific Gas STAR reductions and 2). reductions for 1990 to 1992 were not zeroed out, which would double count reductions if they are already included in the GRI data set. The effect of these changes is a decrease in the fraction of emissions that are calculated with a potential emissions approach, and therefore a decrease in the fraction of "other reductions" that are applied in the production segment. The update results in a decrease in applied "other reductions" of an average of 1 MMT CO_2 Eq. per year over the time series. Stakeholder feedback on the public review draft of the Inventory and on the *2017 Production Memo* support using Gas STAR reductions data only where potential emissions are calculated, and removing them where they create potential double-counting of reductions.

Table 3-61: Production Segment Gas STAR "Other Reductions" Data (Metric Tons CH_4) and Scaling Factors (fraction)

	1990	2005	2011	2012	2013	2014	2015
Total Calculated "Other Reductions"	**NA**	**239,689**	**644,260**	**609,537**	**646,214**	**690,289**	**734,363**
Scaling Factor	NA	0.50	0.27	0.27	0.28	0.28	0.30
"Other Reductions" applied in Inventory	**0**	**120,082**	**174,387**	**166,871**	**178,008**	**195,908**	**219,073**
Previous Total Calculated "Other Reductions"	*3,517*	*251,938*	*656,509*	*621,786*	*658,463*	*702,537*	*NA*
Previous Scaling Factor	*1.00*	*0.62*	*0.44*	*0.45*	*0.46*	*0.49*	*NA*
Previous "Other Reductions" applied in Inventory	*3,517*	*155,687*	*289,932*	*280,909*	*305,749*	*341,687*	*NA*

NA (Not Applicable)

Processing

This section references the memo *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2015: Updates for Natural Gas Systems Processing Segment Emissions (2017 Processing Memo)*.[171]

Overall, recalculations for the processing segment resulted in a decrease of 12.8 MMT CO_2 Eq., or 54 percent comparing the 2014 value from the previous Inventory to this public review draft Inventory. Over the time series, the average change was a decrease of 29 percent. While stakeholders generally support the use of GHGRP data for the update, one stakeholder suggested using the Marchese et al. data set total average emissions per plant to adjust the source-specific GHGRP data upwards. Another stakeholder recommended the use of the GHGRP data and not the Marchese study. The Inventory update uses GHGRP data, unadjusted as described below. For more information, please see the *2017 Processing Memo*.

Station Fugitives, Compressors, Flares and Dehydrators

GHGRP data were used to update the estimates for station fugitives, compressors, flares, and dehydrators. For more information, see the 2017 Processing Memo. Linear interpolation was used to create time series consistency between earlier years' emission factors and activity factors (1990 through 1992) that generally rely on data from GRI/EPA 1996 and the GHGRP emission and activity factors for recent years. However, the plant fugitive emission factors in previous Inventories included plant fugitives but not compressor fugitives, and separate emission factors were applied for compressor emissions (including compressor fugitive and vented sources). There is also some overlap between those categories and the flare and dehydrator categories. Because of these differences, the two sets of emission factors (GRI/EPA and factors calculated from EPA's GHGRP) cannot be directly compared. For the purpose of interpolating for the time series, EPA developed plant-level emission factors for processing stations that include plant and compressor fugitive sources, compressor vented sources, flares, and dehydrators. The previous Inventory emission factors were used for 1990 through 1992; emission factors from EPA's GHGRP were used for 2011 through 2015. Emission factors for 1993 through 2010 were developed through linear interpolation.

EPA incorporated GHGRP average values of reciprocating and centrifugal compressors per processing plant, using year 2015 data. These values were applied for 2011 through 2015. GHGRP data for 2011 through 2015 were used to develop year-specific splits between centrifugal compressor seal types (wet versus dry seals). GHGRP year 2015 data were used to develop emission factors on a per-plant basis for fugitives, flares, and dehydrators, and a per-compressor basis for compressors. Emission factors for dry seal centrifugal compressors were developed using GHGRP data supplemented with the previous Inventory emission factor for dry seal emissions. A stakeholder comment recommended using only 2013 through 2015 GHGRP data to develop the emission factors for compressors and to continue to update emission estimates for this source using annual GHGRP data. EPA will consider this update for future Inventories.

[171] See <https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems-ghg-inventory-additional-information-1990-2015-ghg>.

In order to create time series consistency between earlier years' per plant compressor count estimates (1990 to 1992) and the most recent years' per plant compressor count estimates (2011 to 2015) that were calculated using GHGRP data, compressor counts for the years 1993 through 2010 were calculated using linear interpolation between the data endpoints of 1992 and 2011.

The overall impact of using revised emissions data and activity data from EPA's GHGRP is a decrease in emissions for fugitives and compressors. For the year 2014, the calculated CH_4 emissions decrease due to use of revised emission factors and activity data for processing plant fugitives, compressor venting, flares, and dehydrators is approximately 16.5 MMT CO_2 Eq.

Gas Engines and Turbines

The estimates for gas engines and gas turbines were updated to incorporate data from EPA's GHGRP. For more information, please see the *2017 Processing Memo*. GHGRP data were used to develop an updated value for million horsepower-hours (MMHPhr) per plant for both gas engines and gas turbines. These values were applied to plant counts for years 2011 to 2015. The previous estimates of MMHPhr per plant were retained for 1990 through 1992, and values for 1993 to 2010 were developed by linear interpolation between the 1992 and 2011 values. EPA retained the previous Inventory emission factor and applied it for all years of the time series. The recalculation for gas engines resulted in an average increase in the estimate of 14,190 MT, or 9 percent over the time series. The recalculation for gas turbines resulted in an average decrease in the estimate of 657 MT, or 15 percent over the time series.

Blowdown Venting

The estimate for blowdown venting was updated to incorporate data from GHGRP. For more information, please see the *2017 Processing Memo*. A per-plant emission factor was developed from 2015 GHGRP data, and applied to plant counts for years 2011 through 2015. The previous emission factors were retained for 1990 through 1992, and values for 1993 through 2010 were developed by linear interpolation between the 1992 and 2011 values. The recalculation resulted in an average decrease in the estimate of 7,769 MT or 17 percent over the time series.

Table 3-62: CH_4 Emissions from Processing Plants (Metric Tons CH_4)

Activity Data/Emissions	1990	2005	2011	2012	2013	2014	2015
Plant Total Emissions (MT) (Overlapping Sources)	633,867	245,798	143,187	143,341	153,160	157,063	156,252
Plant Fugitives (MT)	*NA*	*NA*	*14,625*	*14,625*	*15,687*	*16,097*	*16,097*
Reciprocating Compressors (MT)	*NA*	*NA*	*64,413*	*64,413*	*69,089*	*70,896*	*70,896*
Centrifugal Compressors (Wet Seals) (MT)	*NA*	*NA*	*22,061*	*22,387*	*22,767*	*23,143*	*21,428*
Centrifugal Compressors (Dry Seals) (MT)	*NA*	*NA*	*6,959*	*6,787*	*7,936*	*8,260*	*9,165*
Flares (MT)	*NA*	*NA*	*19,776*	*19,776*	*21,212*	*21,767*	*21,767*
Dehydrators (MT)	*NA*	*NA*	*15,353*	*15,353*	*16,468*	*16,899*	*16,899*
Gas Engines (MT)	137,102	168,297	211,002	211,002	226,322	232,241	232,241
Gas Turbines (MT)	3,861	3,424	3,883	3,883	4,165	4,274	4,274
AGR Vents (MT)	16,494	12,267	13,134	13,134	14,088	14,456	14,456
Pneumatic Controllers (MT)	2,414	1,796	1,923	1,923	2,062	2,116	2,116
Blowdowns/Venting (MT)	59,507	34,586	32,251	32,251	34,593	35,497	35,497
Total Processing Emissions (MT)	**853,245**	**466,168**	**405,380**	**405,534**	**434,390**	**445,648**	**444,837**

NA (Not Applicable)

Table 3-63: Previous (last year's) 1990 to 2014 Inventory Estimates for Processing Segment Emissions (Metric Tons CH_4)

Activity Data/Emissions	1990	2005	2011	2012	2013	2014	2015
Previous Plant Total Emissions (Overlapping Sources) (MT)	*633,867*	*621,625*	*761,618*	*793,031*	*800,622*	*843,513*	*NA*
Previous Plants (MT)	*42,295*	*31,457*	*33,681*	*33,681*	*36,126*	*37,126*	*NA*
Previous Recip. Compressors (MT)	*324,939*	*327,869*	*420,871*	*442,077*	*445,551*	*473,829*	*NA*
Previous Centrifugal Compressors (Wet Seals) (MT)	*240,293*	*229,237*	*236,115*	*237,683*	*237,940*	*240,031*	*NA*
Previous Centrifugal Compressors (Dry Seals) (MT)	-	*6,483*	*36,835*	*43,755*	*44,889*	*54,117*	*NA*
Previous Kimray Pumps (MT)	*3,678*	*3,712*	*4,764*	*5,005*	*5,044*	*5,364*	*NA*
Previous Dehydrator Vents (MT)	*22,662*	*22,866*	*29,352*	*30,831*	*31,073*	*33,045*	*NA*
Previous Gas Engines (MT)	*137,102*	*138,338*	*177,578*	*186,526*	*187,991*	*199,923*	*NA*
Previous Gas Turbines (MT)	*3,861*	*3,896*	*5,001*	*5,253*	*5,294*	*5,630*	*NA*
Previous AGR Vents (MT)	*16,494*	*12,267*	*13,134*	*13,134*	*14,088*	*14,478*	*NA*
Previous Pneumatic Controllers (MT)	*2,414*	*1,796*	*1,923*	*1,923*	*2,062*	*2,119*	*NA*
Previous Blowdowns/Venting (MT)	*59,507*	*44,259*	*47,387*	*47,387*	*50,827*	*52,235*	*NA*
Previous-Total Potential Emissions (MT)	*853,245*	*822,180*	*1,006,640*	*1,047,252*	*1,060,884*	*1,117,897*	*NA*
Previous-Gas STAR Reductions (MT)	*(1,488)*	*(155,501)*	*(140,368)*	*(140,449)*	*(140,744)*	*(140,797)*	*NA*
Previous-Regulatory Reductions (MT)	-	*(12,101)*	*(15,533)*	*(16,316)*	*(16,444)*	*(17,488)*	
Previous-Total Net Emissions (MT)	***851,757***	***654,578***	***850,739***	***890,488***	***903,697***	***959,613***	***NA***

NA (Not Applicable)
Note: Parentheses indicate negative values.

Gas STAR Reductions in the Processing Segment

EPA used new data from EPA's GHGRP to calculate emission factors that account for adoption of control technologies and emission reduction practices. To develop estimates over the time series, EPA retained emission factors from the EPA/GRI study for early time series years (1990-1992), applied updated emission factors in recent years (e.g., 2011 forward), and used interpolation to calculate emission factors for intermediate years. This approach results in net emissions calculated for each time series year. Voluntary reductions (derived from Gas STAR data) and regulatory reductions (based on NESHAP implementation) are inherently taken into account with this reproach; therefore, it is no longer necessary to retain these "reduction" line items. EPA has removed the Gas STAR reductions for the processing segment. Over the 1990 to 2014 time series, annual Gas STAR reductions averaged 84,583 MT CH_4, or 2.1 $MMTCO_2$ Eq.

Stakeholder feedback on the public review draft of the Inventory and on the 2017 Processing memo support using Gas STAR reductions data only where potential emissions are calculated, and removing them where they create potential double-counting of reductions.

Transmission and Storage

Although there were no methodological updates to the transmission and storage segment, recalculations due to updated data (e.g., GHGRP station counts, the GHGRP split between dry and wet seal centrifugal compressors, and

GHGRP pneumatic controller data) impacted emission estimates, resulting in an average increase in calculated emissions over the time series from this segment of around 24 metric tons CH_4, or less than 0.01 percent.

Additional information on inclusion of the Aliso Canyon emissions can be found in the Methodology section above and in the *2017 Transmission and Storage Memo*[172] and not in the Recalculation Discussion section as it did not involve recalculation of a previous year of the Inventory.

Distribution

Although there were no methodological updates to the distribution segment, recalculations due to updated data (e.g., GHGRP M&R station counts) impacted emission estimates, resulting in an average decrease in calculated emissions over the time series from this segment of around 664 metric tons CH_4, or 0.1 percent.

Planned Improvements

Plans for 2018 Inventory (1990 through 2016) and Future Inventories

CO_2 Data Update

In this year's Inventory, EPA has held constant the CO_2 values from the previous Inventory as it assesses improvements to the CO_2 estimates. EPA is reviewing CO_2 data from GHGRP and considering updates to improve consistency of data sources and methods between the CH_4 emission estimates (which have been updated in recent years) and the CO_2 emission estimates in Natural Gas Systems. EPA has conducted a preliminary assessment of the CO_2 data and will seek stakeholder feedback on the draft assessment and options for updates. Using GHGRP data to update CO_2 could result in a decrease in the estimate of CO_2 from Natural Gas Systems, primarily due to a potential change in where CO_2 from flaring is estimated--currently, CO_2 from onshore production flaring for both Natural Gas and Petroleum Systems is included in Natural Gas Systems.

Uncertainty

As noted in the Uncertainty discussion, the most recent uncertainty analysis for the natural gas systems emission estimates in the Inventory was conducted for the 1990 to 2009 Inventory that was released in 2011. Since the analysis was last conducted, several of the methods used in the Inventory have changed to reflect improved data and changes in industry practices and equipment. In addition, new studies and other data sources offer improvement to understanding and quantifying the uncertainty of some emission source estimates. EPA is preparing a draft update to the uncertainty analysis conducted for the 2011 Inventory to reflect the new information and will seek stakeholder feedback on the draft analysis as part of the development of the next (i.e., 1990 through 2016) Inventory.

Abandoned Gas Wells

Abandoned wells are not currently included in the Inventory. EPA is seeking emission factors and national activity data available to calculate these emissions. Stakeholder comments supported including this source category in future Inventories, but noted that currently data are limited, and suggested reviewing data that will become available in the future. EPA has identified studies with data on abandoned wells (Townsend-Small et al. 2016, Kang et al. 2016, Brandt et al. 2014), and is considering including an estimate for this source in future Inventories. A preliminary estimate for emissions from abandoned gas wells, based the national emission estimate values from Townsend-Small et al., the range of abandoned well counts in Townsend-Small et al. and Brandt. et al., and the 1990 split between in oil and gas wells in total producing wells population, is around 0.9 to 1.2 MMT CO_2e. EPA seeks stakeholder feedback on abandoned wells.

[172] See <https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems-ghg-inventory-additional-information-1990-2015-ghg>.

Anomalous Leak Events

This Inventory includes an estimate for the 2015 portion of the Aliso Canyon leak event. Next year's Inventory will incorporate the 2016 emission estimate of around 21,000 MT CH_4 for the event. EPA seeks information on other large emissions events. For example, in early 2017 a leaking underwater gas pipeline was identified in Alaska. Early estimates of the leak developed from February through March range from around 2 to 6 tons of CH_4 emitted per day.[173] EPA will consider including an emission estimate for this leak in the 1990-2017 Inventory, to be published in 2019.

Upcoming Data, and Additional Data that Could Inform the Inventory

EPA will continue to review data available from its GHGRP, in particular new data on gathering and boosting stations, gathering pipelines, and transmission pipeline blowdowns and new well-specific information, available in 2017 for the first time. EPA will consider revising its method to take into account the new GHGRP data. EPA will also assess GHGRP data for regional variation in liquids unloading practices and emissions and assess whether to apply GHGRP-based emissions and activity factors at a regional level in the Inventory. Stakeholder comments on the Inventory included a number of options for use of GHGRP processing segment data, including use of a 3-year rolling average to develop emission factors. EPA will consider other approaches for use of GHGRP data in the processing segment.

EPA will assess new data received by the Methane Challenge Program on an ongoing basis, which may be used to confirm or improve existing estimates and assumptions.

EPA continues to track studies that contain data that may be used to update the Inventory. Key studies in progress include DOE-funded work on the following sources: vintage and new plastic pipelines (distribution segment), industrial meters (distribution segment), and sources within the gathering and storage segments.[174] EPA will also continue to assess studies that include and compare both top-down and bottom-up estimates, and which could lead to improved understanding of unassigned high emitters or "superemitters," (e.g., identification of emission sources and information on frequency of high emitters) as recommended in stakeholder comments.

EPA also continues to seek new data that could be used to assess or update the estimates in the Inventory. For example, stakeholder comments have highlighted areas where additional data that could inform the Inventory are currently limited or unavailable:

- Tank malfunction and control efficiency data. See Tanks in Recalculations Discussion.
- Activity data and emissions data for production facilities that do not report to GHGRP. See, for example, Equipment Leaks in Recalculations Discussion.
- Natural gas power plant leak data. One stakeholder noted a recent study (Lavoie et al. 2017) that measured three natural gas power plants and found them to be large sources of natural gas leak emissions, and the stakeholder suggested that EPA evaluate the study and any additional information available on this source.
- Abandoned well activity and emissions data. See above section in Planned Improvements.

EPA will continue to seek available data on these and other sources as part of the process to update the Inventory.

[173] See <http://dec.alaska.gov/spar/ppr/response/sum_fy17/170215201/170215201_index.htm>

[174] See <https://www.energy.gov/under-secretary-science-and-energy/articles/doe-announces-13-million-quantify-and-mitigate-methane>.

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 2015 are reported in Table 3-64.

Table 3-64: NO_x, CO, and NMVOC Emissions from Energy-Related Activities (kt)

Gas/Activity	1990	2005	2011	2012	2013	2014	2015
NO_x	**21,106**	**16,602**	**11,796**	**11,271**	**10,747**	**10,161**	**9,971**
Mobile Fossil Fuel Combustion	10,862	10,295	7,294	6,871	6,448	6,024	5,417
Stationary Fossil Fuel Combustion	10,023	5,858	3,807	3,655	3,504	3,291	3,061
Oil and Gas Activities	139	321	622	663	704	745	745
Waste Combustion	82	128	73	82	91	100	100
International Bunker Fuels[a]	*1,956*	*1,704*	*1,553*	*1,398*	*1,139*	*1,138*	*1,225*
CO	**125,640**	**64,985**	**44,088**	**42,164**	**40,239**	**38,315**	**36,348**
Mobile Fossil Fuel Combustion	119,360	58,615	38,305	36,153	34,000	31,848	29,881
Stationary Fossil Fuel Combustion	5,000	4,648	4,170	4,027	3,884	3,741	3,741
Waste Combustion	978	1,403	1,003	1,318	1,632	1,947	1,947
Oil and Gas Activities	302	318	610	666	723	780	780
International Bunker Fuels[a]	*103*	*133*	*137*	*133*	*129*	*135*	*141*
NMVOCs	**12,620**	**7,191**	**7,759**	**7,558**	**7,357**	**7,154**	**6,867**
Mobile Fossil Fuel Combustion	10,932	5,724	4,562	4,243	3,924	3,605	3,318
Oil and Gas Activities	554	510	2,517	2,651	2,786	2,921	2,921
Stationary Fossil Fuel Combustion	912	716	599	569	539	507	507
Waste Combustion	222	241	81	94	108	121	121
International Bunker Fuels[a]	*57*	*54*	*51*	*46*	*41*	*42*	*47*

[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 2015 were obtained from data published on the National Emission Inventory (NEI) Air Pollutant Emission Trends web site (EPA 2016), and disaggregated based on EPA (2003). Emission estimates for 2012 and 2013 for non-electric generating units (EGU) and non-mobile sources are held constant from 2011 in EPA (2016). 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 2015. 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.[175] These decisions are reflected in the IPCC methodological guidance, including IPCC (2006), 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).[176]

Two transport modes are addressed under the IPCC definition of international bunker fuels: aviation and marine.[177] 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 *2006 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 *2006 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 *2006 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.[178]

Emissions of CO_2 from aircraft are essentially a function of fuel use. Nitrous oxide 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. Carbon dioxide is the primary greenhouse gas emitted from marine shipping.

Overall, aggregate greenhouse gas emissions in 2015 from the combustion of international bunker fuels from both aviation and marine activities were 111.8 MMT CO_2 Eq., or 7.0 percent above emissions in 1990 (see Table 3-65 and Table 3-66). Emissions from international flights and international shipping voyages departing from the United States have increased by 88.8 percent and decreased by 40.6 percent, respectively, since 1990. The majority of these

[175] 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).

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

[177] 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).

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

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 3-65: CO_2, CH_4, and N_2O Emissions from International Bunker Fuels (MMT CO_2 Eq.)

Gas/Mode	1990	2005	2011	2012	2013	2014	2015
CO_2	**103.5**	**113.1**	**111.7**	**105.8**	**99.8**	**103.2**	**110.8**
Aviation	38.0	60.1	64.8	64.5	65.7	69.4	71.8
Commercial	*30.0*	*55.6*	*61.7*	*61.4*	*62.8*	*66.3*	*68.6*
Military	*8.1*	*4.5*	*3.1*	*3.1*	*2.9*	*3.1*	*3.2*
Marine	65.4	53.0	46.9	41.3	34.1	33.8	38.9
CH_4	**0.2**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Aviation[a]	+	+	+	+	+	+	+
Marine	0.2	0.1	0.1	0.1	0.1	0.1	0.1
N_2O	**0.9**	**1.0**	**1.0**	**0.9**	**0.9**	**0.9**	**0.9**
Aviation	0.4	0.6	0.6	0.6	0.6	0.7	0.7
Marine	0.5	0.4	0.4	0.3	0.2	0.2	0.3
Total	**104.5**	**114.2**	**112.8**	**106.8**	**100.7**	**104.2**	**111.8**

+ Does not exceed 0.05 MMT CO_2 Eq.

[a] CH_4 emissions from aviation are estimated to be zero.

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

Table 3-66: CO_2, CH_4, and N_2O Emissions from International Bunker Fuels (kt)

Gas/Mode	1990	2005	2011	2012	2013	2014	2015
CO_2	**103,463**	**113,139**	**111,660**	**105,805**	**99,763**	**103,201**	**110,751**
Aviation	38,034	60,125	64,790	64,524	65,664	69,411	71,805
Marine	65,429	53,014	46,870	41,281	34,099	33,791	38,946
CH_4	**7**	**5**	**5**	**4**	**3**	**3**	**3**
Aviation[a]	0	0	0	0	0	0	0
Marine	7	5	5	4	3	3	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

[a] CH_4 emissions from aviation are estimated to be zero.

Notes: 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 Section 3.1 – 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 (2016) and USAF (1998), and heat content for jet fuel was taken from EIA (2017). 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 value, in units of grams of pollutant per kilogram of fuel consumed (g/kg), was 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 2015 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 2015 are obtained from FAA's AEDT model (FAA 2017). The radar-informed method that was used to estimate CO_2 emissions for commercial aircraft for 1990, and 2000 through 2015 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 2016). 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 3-67. 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 2017) for 1990 through 2001, 2007 through 2015, 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 (2016). 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 3-68.

Table 3-67: Aviation Jet Fuel Consumption for International Transport (Million Gallons)

Nationality	1990	2005	2011	2012	2013	2014	2015
U.S. and Foreign Carriers	3,222	5,983	6,634	6,604	6,748	7,126	7,383
U.S. Military	862	462	319	321	294	318	327
Total	**4,084**	**6,445**	**6,953**	**6,925**	**7,042**	**7,445**	**7,711**

Note: Totals may not sum due to independent rounding.

Table 3-68: Marine Fuel Consumption for International Transport (Million Gallons)

Fuel Type	1990	2005	2011	2012	2013	2014	2015
Residual Fuel Oil	4,781	3,881	3,463	3,069	2,537	2,466	2,718
Distillate Diesel Fuel & Other	617	444	393	280	235	261	492
U.S. Military Naval Fuels	522	471	382	381	308	331	326
Total	**5,920**	**4,796**	**4,237**	**3,730**	**3,081**	**3,058**	**3,536**

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.[179] 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

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

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.[180]

There is also concern regarding the reliability of the existing DOC (2017) 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 2015. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

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

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* (IMO 2014), is being considered.

3.10 Wood Biomass and Biofuels Consumption (IPCC Source Category 1A)

The combustion of biomass fuels such as wood, charcoal, and wood waste and biomass-based fuels such as ethanol, biogas, and biodiesel 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 2015, total CO_2 emissions from the burning of woody biomass in the industrial, residential, commercial, and electricity generation sectors were approximately 198.7 MMT CO_2 Eq. (198,723 kt) (see Table 3-69 and Table 3-70). As the largest consumer of woody biomass, the industrial sector was responsible for 61.2 percent of the CO_2 emissions from this source. The residential sector was the second largest emitter, constituting 22.4 percent of the total, while the commercial and electricity generation sectors accounted for the remainder.

[180] U.S. aviation emission estimates for CO, NO_x, and NMVOCs are reported by EPA's National Emission Inventory (NEI) Air Pollutant Emission Trends website, 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.

Table 3-69: CO_2 Emissions from Wood Consumption by End-Use Sector (MMT CO_2 Eq.)

End-Use Sector	1990	2005	2011	2012	2013	2014	2015
Industrial	135.3	136.3	122.9	125.7	123.1	124.4	121.6
Residential	59.8	44.3	46.4	43.3	59.8	59.8	44.5
Commercial	6.8	7.2	7.1	6.3	7.2	7.6	7.5
Electricity Generation	13.3	19.1	18.8	19.6	21.4	25.9	25.1
Total	**215.2**	**206.9**	**195.2**	**194.9**	**211.6**	**217.7**	**198.7**

Note: Totals may not sum due to independent rounding.

Table 3-70: CO_2 Emissions from Wood Consumption by End-Use Sector (kt)

End-Use Sector	1990	2005	2011	2012	2013	2014	2015
Industrial	135,348	136,269	122,865	125,724	123,149	124,369	121,564
Residential	59,808	44,340	46,402	43,309	59,808	59,808	44,497
Commercial	6,779	7,218	7,131	6,257	7,235	7,569	7,517
Electricity Generation	13,252	19,074	18,784	19,612	21,389	25,908	25,146
Total	**215,186**	**206,901**	**195,182**	**194,903**	**211,581**	**217,654**	**198,723**

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 2015, the United States consumed an estimated 1,153.1 trillion Btu of ethanol, and as a result, produced approximately 78.9 MMT CO_2 Eq. (78,934 kt) (see Table 3-71 and Table 3-72) 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 3-71: CO_2 Emissions from Ethanol Consumption (MMT CO_2 Eq.)

End-Use Sector	1990	2005	2011	2012	2013	2014	2015
Transportation[a]	4.1	22.4	71.5	71.5	73.4	74.9	75.9
Industrial	0.1	0.5	1.1	1.1	1.2	1.0	1.2
Commercial	+	0.1	0.2	0.2	0.2	0.2	1.8
Total	**4.2**	**22.9**	**72.9**	**72.8**	**74.7**	**76.1**	**78.9**

+ Does not exceed 0.05 MMT CO_2 Eq.

[a] See Annex 3.2, Table A-95 for additional information on transportation consumption of these fuels.

Note: Totals may not sum due to independent rounding.

Table 3-72: CO_2 Emissions from Ethanol Consumption (kt)

End-Use Sector	1990	2005	2011	2012	2013	2014	2015
Transportation[a]	4,136	22,414	71,537	71,510	73,359	74,857	75,946
Industrial	56	468	1,146	1,142	1,202	970	1,203
Commercial	34	60	198	175	183	249	1,785
Total	**4,227**	**22,943**	**72,881**	**72,827**	**74,743**	**76,075**	**78,934**

[a] See Annex 3.2, Table A-95 for additional information on transportation consumption of these fuels.

Note: Totals may not sum due to independent rounding.

The transportation sector is assumed to be responsible for all of the biodiesel consumption in the United States (EIA 2017a). Biodiesel is currently produced primarily from soybean oil, but it can be produced from a variety of biomass feedstocks including waste oils, fats and greases. Biodiesel for transportation use appears in low-level blends (less than 5 percent) with diesel fuel, high-level blends (between 6 and 20 percent) with diesel fuel, and 100 percent biodiesel (EIA 2017b).

In 2015, the United States consumed an estimated 190.6 trillion Btu of biodiesel, and as a result, produced approximately 14.1 MMT CO_2 Eq. (14,077 kt) (see Table 3-73 and Table 3-74) of CO_2 emissions. Biodiesel production and consumption has grown significantly since 2001 due to the favorable economics of blending biodiesel into diesel and federal policies that have encouraged use of renewable fuels (EIA 2017b). There was no measured biodiesel consumption prior to 2001 EIA (2017a).

Table 3-73: CO_2 Emissions from Biodiesel Consumption (MMT CO_2 Eq.)

End-Use Sector	1990	2005	2011	2012	2013	2014	2015
Transportation[a]	0.0	0.9	8.3	8.5	13.5	13.3	14.1
Total	**0.0**	**0.9**	**8.3**	**8.5**	**13.5**	**13.3**	**14.1**

+ Does not exceed 0.05 MMT CO_2 Eq.
[a] See Annex 3.2, Table A-95 for additional information on transportation consumption of these fuels.
Note: Totals may not sum due to independent rounding.

Table 3-74: CO_2 Emissions from Biodiesel Consumption (kt)

End-Use Sector	1990	2005	2011	2012	2013	2014	2015
Transportation[a]	0	856	8,349	8,470	13,462	13,349	14,077
Total	**0**	**856**	**8,349**	**8,470**	**13,462**	**13,349**	**14,077**

[a] See Annex 3.2, Table A-95 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 2017a) (see Table 3-75), 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 18.7 MMT C/QBtu (EPA 2010) to U.S. ethanol consumption estimates that were provided in energy units (EIA 2017a) (see Table 3-76). The emissions from biodiesel consumption were calculated by applying an emission factor of 20.1 MMT C/QBtu (EPA 2010) to U.S. biodiesel consumption estimates that were provided in energy units (EIA 2017a) (see Table 3-77).

Table 3-75: Woody Biomass Consumption by Sector (Trillion Btu)

End-Use Sector	1990	2005	2011	2012	2013	2014	2015
Industrial	1,441.9	1,451.7	1,308.9	1,339.4	1,312.0	1,325.0	1,295.1
Residential	580.0	430.0	450.0	420.0	580.0	580.0	431.5
Commercial	65.7	70.0	69.2	60.7	70.2	73.4	72.9
Electricity Generation	128.5	185.0	182.2	190.2	207.4	251.3	243.9
Total	**2,216.2**	**2,136.7**	**2,010.2**	**2,010.3**	**2,169.5**	**2,229.6**	**2,043.3**

Note: Totals may not sum due to independent rounding.

Table 3-76: Ethanol Consumption by Sector (Trillion Btu)

End-Use Sector	1990	2005	2011	2012	2013	2014	2015
Transportation	60.4	327.4	1,045.0	1,044.6	1,071.6	1,092.8	1,133.9
Industrial	0.8	6.8	16.7	16.7	17.6	14.4	15.0
Commercial	0.5	0.9	2.9	2.6	2.7	4.1	4.2
Total	**61.7**	**335.1**	**1,064.6**	**1,063.8**	**1,091.8**	**1,111.3**	**1,153.1**

Note: Totals may not sum due to independent rounding.

Table 3-77: Biodiesel Consumption by Sector (Trillion Btu)

End-Use Sector	1990	2005	2011	2012	2013	2014	2015
Transportation	0.0	11.6	113.1	114.7	182.3	180.8	190.6
Total	**0.0**	**11.6**	**113.1**	**114.7**	**182.3**	**180.8**	**190.6**

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 and biodiesel 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 2015. Details on the emission trends through time are described in more detail in the Methodology section, above.

Recalculations Discussion

Wood consumption and ethanol values for 1990 through 2014 were not revised relative to the previous Inventory, as there were no historical revisions from EIA's *Monthly Energy Review* (EIA 2017a). Carbon dioxide emission estimates from biodiesel consumption were added for 1990 through 2015 to quantify biogenic emissions from the combustion of biodiesel. In previous Inventories, biodiesel consumption was subtracted from fossil fuel combustion estimates but not accounted for in this chapter.

Planned Improvements

The availability of facility-level combustion emissions through EPA's Greenhouse Gas Reporting Program (GHGRP) will be examined to help better characterize the industrial sector's energy consumption in the United States, and further classify woody biomass consumption by 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.[181] 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.[182]

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

[182] See <http://www.ipcc-nggip.iges.or.jp/public/tb/TFI_Technical_Bulletin_1.pdf>.

Currently emission estimates from biomass and biomass-based fuels included in this inventory are limited to woody biomass, ethanol, and biodiesel. Other forms of biomass-based fuel consumption include biogas. An effort will be made to examine sources of data for biogas including data from EIA for possible inclusion. EIA (2017a) natural gas data already deducts biogas used in the natural gas supply so no adjustments are needed to the natural gas fuel consumption data to account for biogas.

As per discussion in Section 3.1, an additional planned improvement is to evaluate and potentially update our method for allocating motor gasoline consumption across the Transportation, Industrial and Commercial sectors to improve accuracy and create a more consistent time series. Further research will be conducted to determine if changes also need to be made to ethanol allocation between these sectors to match gasoline's sectoral distribution.