3. Energy

Energy-related activities were the primary sources of U.S. anthropogenic greenhouse gas emissions, accounting for 83.1 percent of total greenhouse gas emissions on a carbon dioxide (CO_2) equivalent basis in 2018.[1] This included 97, 40, and 10 percent of the nation's CO_2, methane (CH_4), and nitrous oxide (N_2O) emissions, respectively. Energy-related CO_2 emissions alone constituted 78.6 percent of U.S. greenhouse gas 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 (4.5 percent collectively).

Emissions from fossil fuel combustion comprise the vast majority of energy-related emissions, with CO_2 being the primary gas emitted (see Figure 3-1). Globally, approximately 32,840 million metric tons (MMT) of CO_2 were added to the atmosphere through the combustion of fossil fuels in 2017, of which the United States accounted for approximately 15 percent.[2] Due to their relative importance, fossil fuel combustion-related CO_2 emissions are considered separately and in more detail than other energy-related emissions (see Figure 3-2).

Fossil fuel combustion also emits CH_4 and N_2O. Stationary combustion of fossil fuels was the second largest source of N_2O emissions in the United States and mobile fossil fuel combustion was the fourth largest source. 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, coal mining, and petroleum systems.

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

[2] Global CO_2 emissions from fossil fuel combustion were taken from International Energy Agency *CO_2 Emissions from Fossil Fuels Combustion Overview* Available at: <https://webstore.iea.org/co2-emissions-from-fuel-combustion-2019> (IEA 2019).

Figure 3-1: 2018 Energy Chapter Greenhouse Gas Sources (MMT CO_2 Eq.)

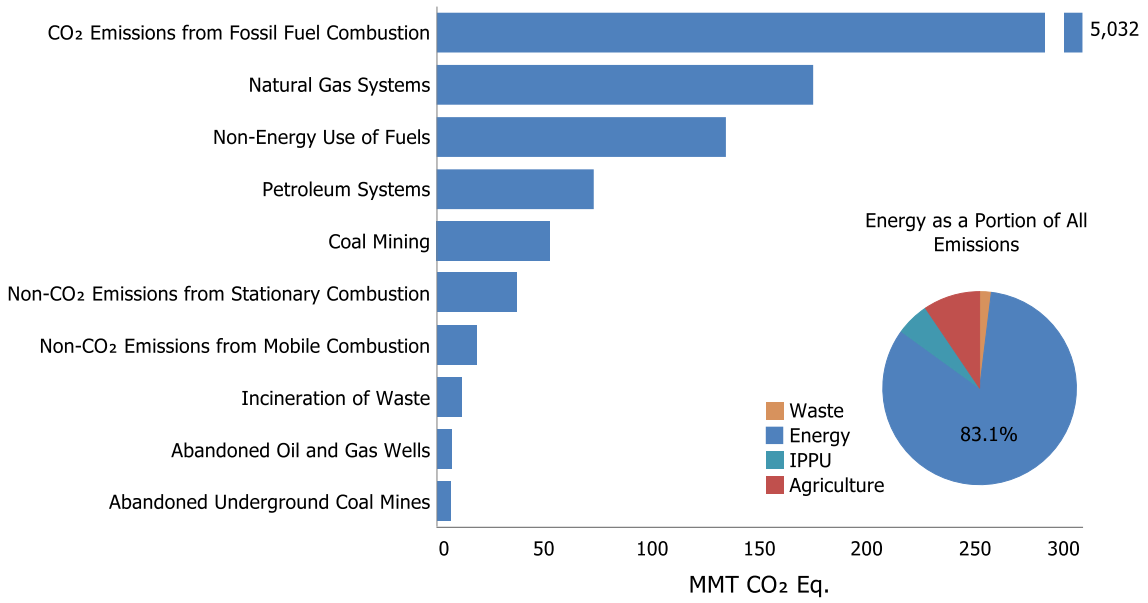


Figure 3-2: 2018 U.S. Fossil Carbon Flows (MMT CO_2 Eq.)

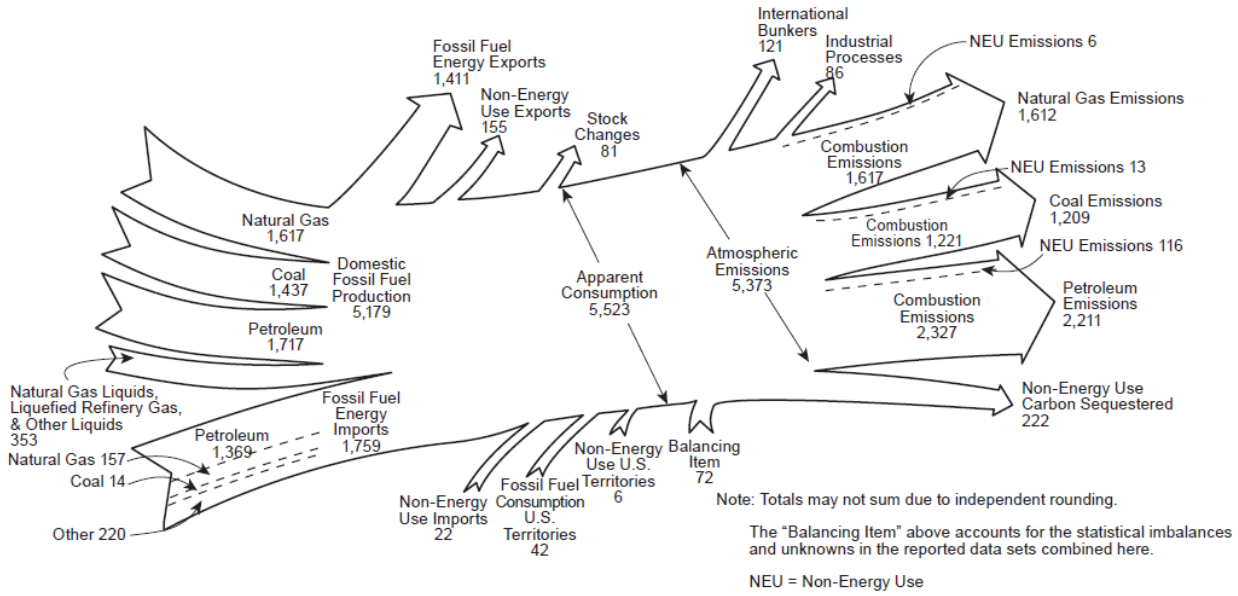


Table 3-1 summarizes emissions from the Energy sector in units of MMT CO_2 Eq., while unweighted gas emissions in kilotons (kt) are provided in Table 3-2. Overall, emissions due to energy-related activities were 5,547.2 MMT CO_2 Eq. in 2018,[3] an increase of 3.9 percent since 1990 and an increase of 3.0 percent since 2017.

[3] Following the current 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.

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

Gas/Source	1990	2005	2014	2015	2016	2017	2018
CO_2	**4,909.3**	**5,930.3**	**5,375.4**	**5,231.5**	**5,119.8**	**5,081.3**	**5,249.3**
Fossil Fuel Combustion	4,740.0	5,740.7	5,184.8	5,031.8	4,942.4	4,892.2	5,031.8
Transportation	*1,469.1*	*1,856.1*	*1,713.7*	*1,725.3*	*1,765.3*	*1,787.3*	*1,820.7*
Electric Power	*1,820.0*	*2,400.0*	*2,037.1*	*1,900.6*	*1,808.9*	*1,732.0*	*1,752.8*
Industrial	*857.0*	*850.1*	*812.9*	*801.3*	*801.4*	*805.0*	*833.2*
Residential	*338.2*	*357.9*	*346.8*	*317.8*	*293.1*	*293.8*	*337.3*
Commercial	*228.2*	*226.9*	*232.8*	*245.4*	*232.3*	*232.8*	*246.5*
U.S. Territories	*27.6*	*49.7*	*41.4*	*41.4*	*41.4*	*41.4*	*41.4*
Non-Energy Use of Fuels	119.5	139.7	120.0	127.0	113.7	123.1	134.6
Petroleum Systems	9.6	12.2	30.5	32.6	23.0	24.5	36.8
Natural Gas Systems	32.2	25.3	29.6	29.3	29.9	30.4	35.0
Incineration of Waste	8.0	12.5	10.4	10.8	10.9	11.1	11.1
Abandoned Oil and Gas Wells	+	+	+	+	+	+	+
Biomass-Wood[a]	*215.2*	*206.9*	*233.8*	*224.7*	*216.3*	*221.4*	*229.1*
International Bunker Fuels[b]	*103.5*	*113.1*	*103.4*	*110.9*	*116.6*	*120.1*	*122.1*
Biofuels-Ethanol[a]	*4.2*	*22.9*	*76.1*	*78.9*	*81.2*	*82.1*	*81.9*
Biofuels-Biodiesel[a]	*0.0*	*0.9*	*13.3*	*14.1*	*19.6*	*18.7*	*17.9*
CH_4	**361.2**	**292.0**	**275.6**	**269.3**	**253.9**	**257.3**	**253.9**
Natural Gas Systems	183.3	158.1	141.1	141.9	135.8	139.3	140.0
Coal Mining	96.5	64.1	64.6	61.2	53.8	54.8	52.7
Petroleum Systems	46.1	38.8	43.5	40.5	39.0	38.7	36.2
Stationary Combustion	8.6	7.8	8.9	8.5	7.9	7.8	8.6
Abandoned Oil and Gas Wells	6.6	7.0	7.1	7.1	7.2	7.1	7.0
Abandoned Underground Coal Mines	7.2	6.6	6.3	6.4	6.7	6.4	6.2
Mobile Combustion	12.9	9.6	4.1	3.6	3.4	3.3	3.1
Incineration of Waste	+	+	+	+	+	+	+
International Bunker Fuels[b]	*0.2*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*
N_2O	**67.6**	**72.1**	**53.1**	**49.2**	**47.8**	**45.2**	**44.0**
Stationary Combustion	25.1	34.3	33.0	30.5	30.0	28.6	28.4
Mobile Combustion	42.0	37.3	19.7	18.3	17.4	16.3	15.2
Incineration of Waste	0.5	0.4	0.3	0.3	0.3	0.3	0.3
Petroleum Systems	+	+	+	+	+	+	0.1
Natural Gas Systems	+	+	+	+	+	+	+
International Bunker Fuels[b]	*0.9*	*1.0*	*0.9*	*1.0*	*1.0*	*1.1*	*1.1*
Total	**5,338.1**	**6,294.4**	**5,704.0**	**5,550.1**	**5,421.6**	**5,383.8**	**5,547.2**

Note: Totals may not sum due to independent rounding.

+ Does not exceed 0.05 MMT CO_2 Eq.

[a] Emissions from Wood Biomass, Ethanol, and Biodiesel Consumption are not included specifically in summing Energy sector totals. Net carbon fluxes from changes in biogenic carbon reservoirs are accounted for in the estimates for LULUCF.

[b] Emissions from International Bunker Fuels are not included in totals. These values are presented for informational purposes only, in line with the *2006 IPCC Guidelines* and UNFCCC reporting obligations.

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

Gas/Source	1990	2005	2014	2015	2016	2017	2018
CO_2	**4,909,296**	**5,930,296**	**5,375,404**	**5,231,530**	**5,119,841**	**5,081,321**	**5,249,295**
Fossil Fuel Combustion	4,740,006	5,740,660	5,184,776	5,031,762	4,942,421	4,892,234	5,031,813
Non-Energy Use of Fuels	119,530	139,707	120,030	127,027	113,651	123,133	134,576
Petroleum Systems	9,630	12,163	30,536	32,644	22,980	24,472	36,814
Natural Gas Systems	32,174	25,291	29,620	29,334	29,862	30,365	34,972
Incineration of Waste	7,951	12,469	10,435	10,756	10,919	11,111	11,113

Abandoned Oil and Gas Wells	6	7	7	7	7	7	7
Biomass-Wood[a]	*215,186*	*206,901*	*233,762*	*224,730*	*216,293*	*221,432*	*229,085*
International Bunker Fuels[b]	*103,463*	*113,139*	*103,400*	*110,887*	*116,594*	*120,107*	*122,088*
Biofuels-Ethanol[a]	*4,227*	*22,943*	*76,075*	*78,934*	*81,250*	*82,088*	*81,917*
Biofuels-Biodiesel[a]	*0*	*856*	*13,349*	*14,077*	*19,648*	*18,705*	*17,936*
CH_4	**14,449**	**11,680**	**11,023**	**10,772**	**10,158**	**10,292**	**10,156**
Natural Gas Systems	7,332	6,324	5,643	5,674	5,433	5,570	5,598
Coal Mining	3,860	2,565	2,583	2,449	2,154	2,191	2,109
Petroleum Systems	1,844	1,553	1,739	1,622	1,559	1,548	1,449
Stationary Combustion	344	313	355	340	318	312	346
Abandoned Oil and Gas Wells	263	278	284	286	289	282	281
Abandoned Underground Coal Mines	288	264	253	256	268	257	247
Mobile Combustion	518	383	166	146	138	131	126
Incineration of Waste	+	+	+	+	+	+	+
International Bunker Fuels[b]	*7*	*5*	*3*	*4*	*4*	*4*	*4*
N_2O	**227**	**242**	**178**	**165**	**160**	**152**	**148**
Stationary Combustion	84	115	111	102	101	96	95
Mobile Combustion	141	125	66	62	58	55	51
Incineration of Waste	2	1	1	1	1	1	1
Petroleum Systems	+	+	+	+	+	+	+
Natural Gas Systems	+	+	+	+	+	+	+
International Bunker Fuels[b]	*3*	*3*	*3*	*3*	*3*	*4*	*4*

Note: Totals may not sum due to independent rounding.
+ Does not exceed 0.5 kt.
[a] Emissions from Wood Biomass, Ethanol, and Biodiesel Consumption are not included specifically in summing Energy sector totals. Net carbon fluxes from changes in biogenic carbon reservoirs are accounted for in the estimates for LULUCF.
[b] Emissions from International Bunker Fuels are not included in totals. These values are presented for informational purposes only, in line with the *2006 IPCC Guidelines* and UNFCCC reporting obligations.

Each year, some emission and sink estimates in the Inventory are recalculated and revised with improved methods and/or data. In general, recalculations are made to the U.S. greenhouse gas emission estimates either to incorporate new methodologies or, most commonly, to update recent historical data. These improvements are implemented consistently across the previous Inventory's time series (i.e., 1990 to 2017) to ensure that the trend is accurate. Updates to CO_2 emissions from Fossil Fuel Combustion in the Energy sector resulted in an average decrease over the time series of about 6.6 MMT CO_2 Eq. For more information on specific methodological updates, please see the Recalculations for each category, in this chapter.

Box 3-1: Methodological Approach for Estimating and Reporting U.S. Emissions and Removals, including Relationship to EPA's Greenhouse Gas Reporting Program

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 removals 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) in the *2006 IPCC Guidelines for National Greenhouse Gas Inventories (2006 IPCC Guidelines)*. Additionally, the calculated emissions and removals 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 removals by all nations providing their inventories to the UNFCCC ensures that these reports are comparable. The presentation of emissions and removals provided in the Energy chapter do not preclude alternative examinations, but rather, this chapter presents emissions and removals 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 application of methods used to calculate emissions and removals from energy-related activities.

Energy Data from EPA's Greenhouse Gas Reporting Program

EPA's Greenhouse Gas Reporting Program (GHGRP)[4] dataset and the data presented in this Inventory are complementary. The Inventory was used to guide the development of the GHGRP, particularly in terms of scope and coverage of both sources and gases. 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 Energy sector categories to improve the national estimates presented in this Inventory consistent with IPCC guidelines (see Box 3-3 of this chapter, and sections 3.4 Coal Mining, 3.6 Petroleum Systems, and 3.7 Natural Gas Systems).[5] Methodologies used in EPA's GHGRP are consistent with IPCC guidelines, including higher tier methods. Under EPA's GHGRP, facilities collect detailed information specific to their operations according to detailed measurement standards. 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.

In addition to using GHGRP data to estimate emissions (Section 3.4 Coal Mining, 3.6 Petroleum Systems, and Section 3.7 Natural Gas Systems), EPA also uses the GHGRP fuel consumption activity data in the Energy sector to disaggregate 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 (See Box 3-3). The industrial end-use sector activity data collected for the Inventory (EIA 2019) 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, GHGRP data are used to provide a more detailed breakout of total emissions in the industrial end-use sector within that source category.

As indicated in the respective Planned Improvements sections for source categories in this chapter, EPA

[4] On October 30, 2009, the U.S. Environmental Protection Agency (EPA) published a rule requiring annual reporting of greenhouse gas data from large greenhouse gas emission sources in the United States. Implementation of the rule, codified at 40 CFR Part 98, is referred to as EPA's Greenhouse Gas Reporting Program (GHGRP).

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

continues to examine the uses of facility-level GHGRP data to improve the national estimates presented in this Inventory. See Annex 9 for more information on use of EPA's GHGRP in the Inventory.

3.1 Fossil Fuel Combustion (CRF 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	2014	2015	2016	2017	2018
CO_2	4,740.0	5,740.7	5,184.8	5,031.8	4,942.4	4,892.2	5,031.8
CH_4	21.5	17.4	13.0	12.1	11.4	11.1	11.8
N_2O	67.1	71.6	52.7	48.9	47.4	44.9	43.6
Total	**4,828.7**	**5,829.7**	**5,250.5**	**5,092.8**	**5,001.2**	**4,948.2**	**5,087.2**

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	2014	2015	2016	2017	2018
CO_2	4,740,006	5,740,660	5,184,776	5,031,762	4,942,421	4,892,234	5,031,813
CH_4	862	696	521	485	455	443	471
N_2O	225	240	177	164	159	151	146

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 2018, CO_2 emissions from fossil fuel combustion increased by 2.9 percent relative to the previous year. The increase in CO_2 emissions from fossil fuel consumption was a result of a 4.1 percent increase in total energy use and reflects a continued shift from coal to natural gas. Carbon dioxide emissions from natural gas consumption increased by 160.3 MMT CO_2 Eq. in 2018, an 11.0 percent increase from 2017, while CO_2 emissions from coal consumption decreased by 4.7 percent. The increase in natural gas consumption and emissions in 2018 is observed across all sectors and is primarily driven by increased energy use from greater heating and cooling needs due to a colder winter and hotter summer in 2018 (in comparison to 2017). In 2018, CO_2 emissions from fossil fuel combustion were 5,031.8 MMT CO_2 Eq., or 6.2 percent above emissions in 1990 (see Table 3-5).[6]

[6] 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	2014	2015	2016	2017	2018
Coal	**1,717.3**	**2,111.2**	**1,652.4**	**1,424.7**	**1,307.5**	**1,267.5**	**1,208.5**
Residential	3.0	0.8	NO	NO	NO	NO	NO
Commercial	12.0	9.3	3.8	3.0	2.3	2.0	1.8
Industrial	155.2	115.3	76.0	66.3	59.2	54.4	49.8
Transportation	NE	NE	NE	NE	NE	NE	NE
Electric Power	1,546.5	1,982.8	1,568.6	1,351.4	1,242.0	1,207.1	1,152.9
U.S. Territories	0.6	3.0	4.0	4.0	4.0	4.0	4.0
Natural Gas	**999.7**	**1,167.0**	**1,420.0**	**1,460.2**	**1,471.8**	**1,451.4**	**1,611.6**
Residential	237.8	262.2	277.7	252.7	238.4	241.5	273.7
Commercial	142.0	162.9	189.2	175.4	170.5	173.2	192.6
Industrial	408.5	388.6	467.1	464.4	474.8	485.8	514.8
Transportation	36.0	33.1	40.2	39.4	40.1	42.3	50.2
Electric Power	175.4	318.9	442.9	525.2	545.0	505.6	577.4
U.S. Territories	NO	1.3	3.0	3.0	3.0	3.0	3.0
Petroleum	**2,022.4**	**2,462.1**	**2,111.9**	**2,146.5**	**2,162.7**	**2,172.9**	**2,211.3**
Residential	97.4	94.9	69.1	65.1	54.8	52.3	63.5
Commercial	74.2	54.7	39.8	67.1	59.5	57.6	52.1
Industrial	293.3	346.2	269.9	270.5	267.4	264.8	268.6
Transportation	1,433.1	1,823.0	1,673.5	1,685.9	1,725.2	1,745.0	1,770.5
Electric Power	97.5	97.9	25.3	23.7	21.4	18.9	22.2
U.S. Territories	26.9	45.4	34.3	34.3	34.3	34.3	34.3
Geothermal[a]	**0.5**	**0.5**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**
Total	**4,740.0**	**5,740.7**	**5,184.8**	**5,031.8**	**4,942.5**	**4,892.3**	**5,031.8**

Note: Totals may not sum due to independent rounding.

NE (Not Estimated)

NO (Not Occurring)

[a] Although not technically a fossil fuel, geothermal energy-related CO_2 emissions are included for reporting purposes.

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 usage patterns, however, tend to be more a function of aggregate societal trends that affect the scale of energy use (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.[7]

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

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 2018 CO_2 Emissions from Fossil Fuel Combustion for Selected Fuels and Sectors (MMT CO_2 Eq. and Percent)

Sector	Fuel Type	2014 to 2015		2015 to 2016		2016 to 2017		2017 to 2018		Total 2018
Electric Power	Coal	-217.2	-13.8%	-109.4	-8.1%	-34.9	-2.8%	-54.2	-4.5%	1,152.9
Electric Power	Natural Gas	82.3	18.6%	19.8	3.8%	-39.4	-7.2%	71.7	14.2%	577.4
Electric Power	Petroleum	-1.6	-6.4%	-2.2	-9.3%	-2.5	-11.8%	3.3	17.4%	22.2
Transportation	Petroleum	12.4	0.7%	39.4	2.3%	19.8	1.1%	25.5	1.5%	1,770.5
Residential	Natural Gas	-24.9	-9.0%	-14.3	-5.7%	3.1	1.3%	32.3	13.4%	273.7
Commercial	Natural Gas	-13.8	-7.3%	-4.9	-2.8%	2.6	1.6%	19.4	11.2%	192.6
Industrial	Natural Gas	-2.6	-0.6%	10.4	2.2%	11.0	2.3%	29.0	6.0%	514.8
All Sectors[a]	**All Fuels[a]**	**-153.0**	**-3.0%**	**-89.3**	**-1.8%**	**-50.2**	**-1.0%**	**139.6**	**2.9%**	**5,031.8**

[a] Includes sector and fuel combinations not shown in this table.

As shown in Table 3-6, recent trends in CO_2 emissions from fossil fuel combustion show a 3.0 percent decrease from 2014 to 2015, then a 1.8 percent decrease from 2015 to 2016, a 1.0 percent decrease from 2016 to 2017, and a 2.9 percent increase from 2017 to 2018. These changes contributed to an overall 3.0 percent decrease in CO_2 emissions from fossil fuel combustion from 2014 to 2018.

Trends in CO_2 emissions from fossil fuel combustion over the past five years have been largely driven by the electric power sector, which historically has accounted for the largest portion of these emissions. The types of fuels consumed to produce electricity have changed in recent years. Total electric power generation decreased by 1.5 percent from 2014 to 2017 but increased by 3.4 percent from 2017 to 2018. Emissions increased from 2017 to 2018 due to increasing electric power generation from natural gas and petroleum. Carbon dioxide emissions from coal consumption for electric power generation decreased by 26.5 percent since 2014, which can be largely attributed to a shift to the use of less-CO_2-intensive natural gas to generate electricity and a rapid increase in renewable energy capacity additions in the electric power sector in recent years.

The trends in CO_2 emissions from fossil fuel combustion over the past five years also follow changes in heating degree days. Emissions from natural gas consumption in the residential and commercial sectors increased by 13.4 percent and 11.2 percent from 2017 to 2018, respectively. This trend can be largely attributed to a 12 percent increase in heating degree days, which led to an increased demand for heating fuel and electricity for heat in these sectors. Industrial consumption of natural gas is dependent on market effects of supply and demand in addition to weather-related heating needs. Electric power sector consumption of natural gas primarily increased due to increased production capacity as natural gas-fired plants replaced coal-fired plants and increased electricity demands related to heating and cooling needs (EIA 2018; EIA 2019b).

Petroleum use in the transportation sector is another major driver of emissions, representing the largest source of CO_2 emissions from fossil fuel combustion in 2018. Emissions from petroleum consumption for transportation have increased by 5.8 percent since 2014 and are primarily attributed to a 7.1 percent increase in vehicle miles traveled (VMT) over the same time period.

In the United States, 80 percent of the energy used in 2018 was produced through the combustion of fossil fuels such as petroleum, natural gas, and coal (see Figure 3-3 and Figure 3-4). Specifically, petroleum supplied the largest share of domestic energy demands, accounting for 36 percent of total U.S. energy used in 2018. Natural gas and coal followed in order of energy demand importance, accounting for approximately 31 percent and 13 percent of total U.S. energy used, respectively. Petroleum was consumed primarily in the transportation end-use sector and the vast majority of coal was used in the electric power sector. Natural gas was broadly consumed in all end-use sectors except transportation (see Figure 3-5) (EIA 2019a). The remaining portion of energy used in 2018 was

supplied by nuclear electric power (8 percent) and by a variety of renewable energy sources (11 percent), primarily hydroelectric power, wind energy, and biofuels (EIA 2019a).[8]

Figure 3-3: 2018 U.S. Energy Use by Energy Source (Percent)

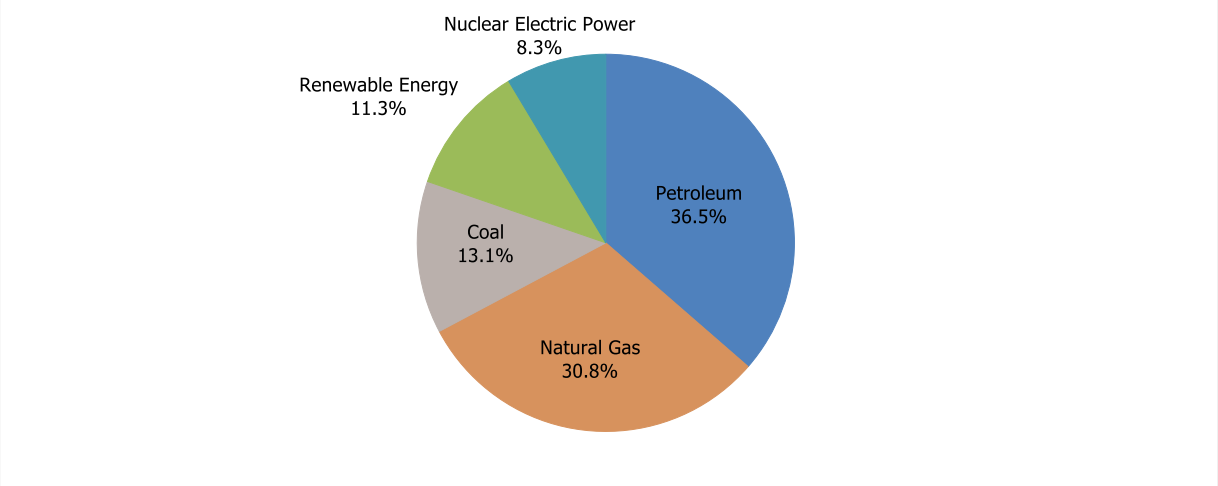
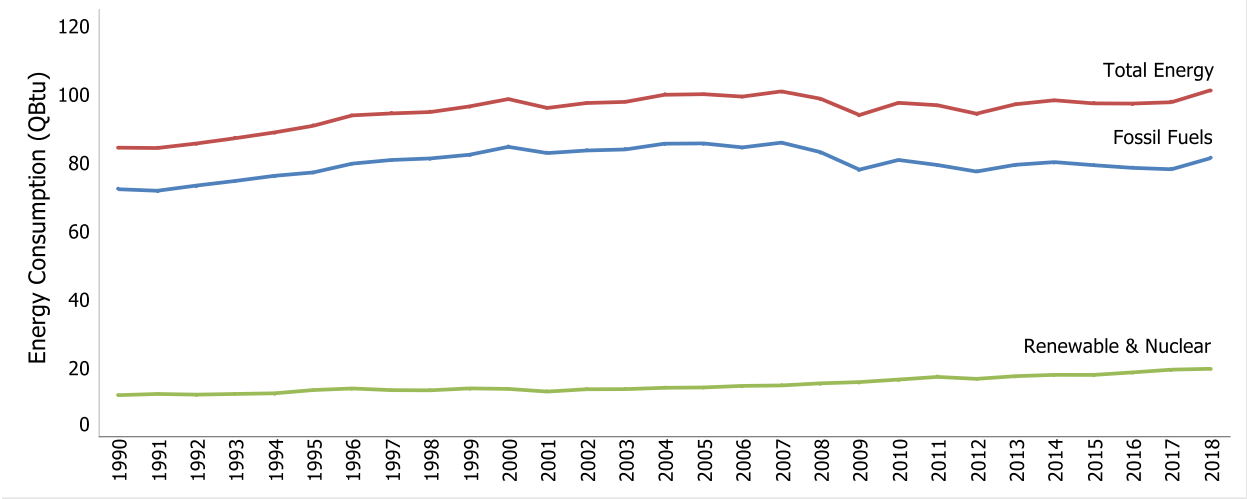
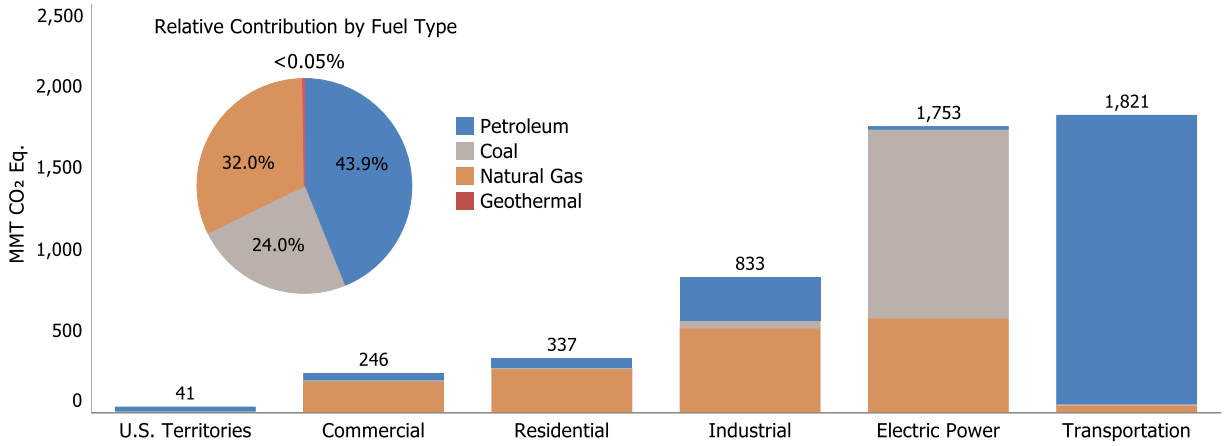


Figure 3-4: Annual U.S. Energy Use (Quadrillion Btu)



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

Figure 3-5: 2018 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type (MMT CO_2 Eq.)



Fossil fuels are generally combusted for the purpose of producing energy for useful heat and work. During the combustion process, the C stored in the fuels is oxidized and emitted as CO_2 and smaller amounts of other gases, including CH_4, carbon monoxide (CO), and non-methane volatile organic compounds (NMVOCs).[9] 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 3-2: Weather and Non-Fossil Energy Effects on CO_2 Emissions from Fossil Fuel Combustion Trends

The United States in 2018 experienced a significantly colder winter overall compared to 2017, as heating degree days increased 11.8 percent. Colder winter conditions compared to 2017 impacted the amount of energy required for heating. In 2018 heating degree days in the United States were 5.7 percent below normal (see Figure 3-6). Cooling degree days increased by 11.1 percent compared to 2017, which increased demand for air conditioning in the residential and commercial sector. Hotter summer conditions compared to 2017 impacted the amount of energy required for cooling, and 2018 cooling degree days in the United States were 29.2 percent above normal (see Figure 3-7) (EIA 2019a).10 The combination of colder winter and hotter summer conditions led to residential and commercial energy consumption increases of 14.8 and 5.9 percent, respectively.

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

[10] 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 1981 through 2010. The variation in these normals during this time period was ±15 percent and ±23 percent for heating and cooling degree days, respectively (99 percent confidence interval).

Figure 3-6: Annual Deviations from Normal Heating Degree Days for the United States (1950–2018, Index Normal = 100)

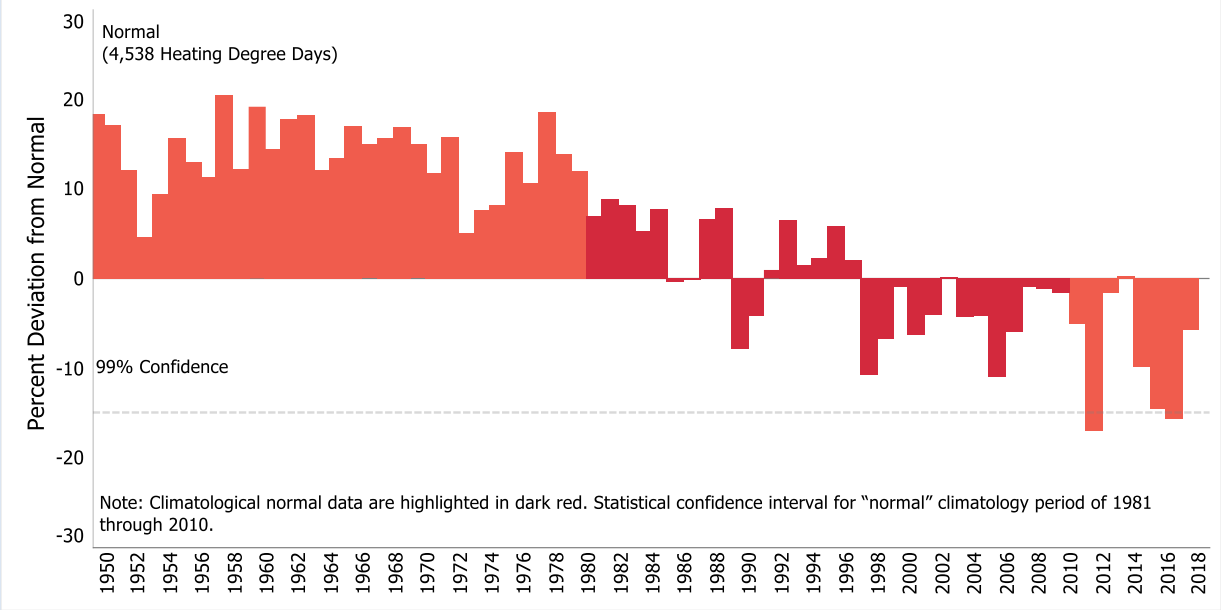
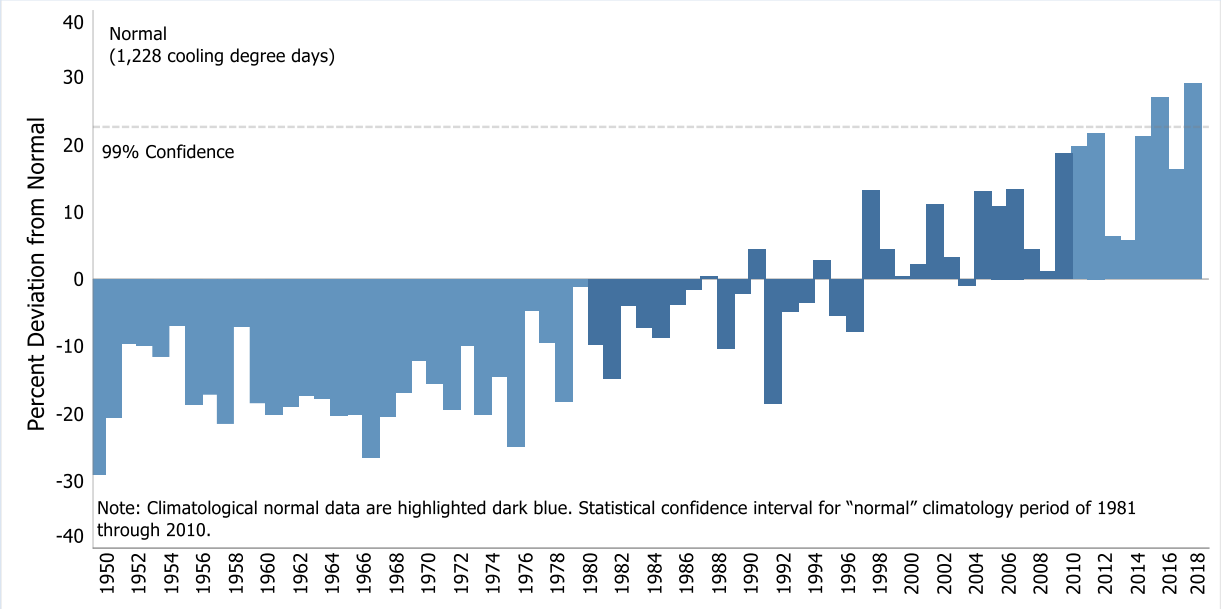


Figure 3-7: Annual Deviations from Normal Cooling Degree Days for the United States (1950–2018, Index Normal = 100)



The carbon intensity of the electric power sector is impacted by the amount of non-fossil energy sources of electricity. The utilization (i.e., capacity factors)[11] of nuclear power plants in 2018 remained high at 93 percent. In 2018, nuclear power represented 20 percent of total electricity generation. Since 1990, the wind and solar power sectors have shown strong growth (between an observed minimum of 89 percent annual electricity generation growth to a maximum of 162 percent annual electricity generation growth), such that, they have become relatively important electricity sources. Between 1990 and 2018, renewable energy generation (in kWh) from solar and wind energy have increased from 0.1 percent in 1990 to 8 percent of total electricity generation in 2018, which helped drive the decrease in the carbon intensity of the electricity supply in the United States.

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	2014	2015	2016	2017	2018
Transportation	**1,524.0**	**1,903.0**	**1,737.6**	**1,747.3**	**1,786.1**	**1,806.8**	**1,839.0**
CO_2	1,469.1	1,856.1	1,713.7	1,725.3	1,765.3	1,787.3	1,820.7
CH_4	12.9	9.6	4.1	3.6	3.4	3.3	3.1
N_2O	42.0	37.3	19.7	18.3	17.4	16.3	15.2
Electric Power	**1,840.9**	**2,430.9**	**2,067.1**	**1,928.3**	**1,836.2**	**1,757.9**	**1,778.5**
CO_2	1,820.0	2,400.0	2,037.1	1,900.6	1,808.9	1,732.0	1,752.8
CH_4	0.4	0.9	1.1	1.2	1.2	1.1	1.2
N_2O	20.5	30.1	28.9	26.5	26.2	24.8	24.4
Industrial	**861.9**	**854.7**	**817.2**	**805.6**	**805.6**	**809.3**	**837.5**
CO_2	857.0	850.1	812.9	801.3	801.4	805.0	833.2
CH_4	1.8	1.7	1.6	1.6	1.6	1.6	1.6
N_2O	3.1	2.9	2.7	2.6	2.6	2.6	2.6
Residential	**344.5**	**362.9**	**352.8**	**323.1**	**297.9**	**298.4**	**342.7**
CO_2	338.2	357.9	346.8	317.8	293.1	293.8	337.3
CH_4	5.2	4.1	5.0	4.5	3.9	3.8	4.5
N_2O	1.0	0.9	1.0	0.9	0.8	0.8	0.9
Commercial	**229.7**	**228.3**	**234.3**	**247.0**	**233.9**	**234.3**	**248.1**
CO_2	228.2	226.9	232.8	245.4	232.3	232.8	246.5
CH_4	1.1	1.1	1.1	1.2	1.2	1.2	1.2
N_2O	0.4	0.3	0.3	0.4	0.3	0.3	0.3
U.S. Territories[a]	**27.7**	**49.9**	**41.5**	**41.5**	**41.5**	**41.5**	**41.5**
Total	**4,828.7**	**5,829.7**	**5,250.5**	**5,092.8**	**5,001.2**	**4,948.2**	**5,087.2**

Notes: Totals may not sum due to independent rounding.

[a] U.S. Territories are not apportioned by sector, and emissions shown in the table are total greenhouse gas emissions from all fuel combustion sources.

[11] 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 (2019c).

Other than CO_2, gases emitted from stationary combustion include the greenhouse gases CH_4 and N_2O and greenhouse gas precursors nitrogen oxides (NO_x), CO, and NMVOCs.[12] 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 also produces emissions of CH_4, N_2O, and greenhouse gas precursors 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. Nitrous oxide 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 electric power to the sectors in which it is used. Four end-use sectors were defined: transportation, industrial, residential, and commercial. In the table below, electric power emissions have been distributed to each end-use sector based upon the sector's share of national electricity use, with the exception of CH_4 and N_2O from transportation.[13] Emissions from U.S. Territories are also calculated separately due to a lack of end-use-specific consumption data.[14] This method assumes that emissions from combustion sources are distributed across the four end-use sectors based on the ratio of electricity use 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	2014	2015	2016	2017	2018
Transportation	**1,527.1**	**1,907.7**	**1,742.0**	**1,751.5**	**1,790.3**	**1,811.1**	**1,843.8**
CO_2	1,472.1	1,860.8	1,718.2	1,729.5	1,769.5	1,791.6	1,825.4
CH_4	12.9	9.6	4.1	3.6	3.4	3.3	3.1
N_2O	42.0	37.3	19.7	18.3	17.4	16.3	15.2
Industrial	**1,556.2**	**1,600.5**	**1,418.9**	**1,363.1**	**1,331.0**	**1,321.2**	**1,331.8**
CO_2	1,543.4	1,586.4	1,405.9	1,350.8	1,319.0	1,309.4	1,320.4
CH_4	2.0	2.0	1.9	1.9	1.9	1.9	2.0
N_2O	10.8	12.2	11.1	10.3	10.1	9.9	9.4
Residential	**944.1**	**1,229.9**	**1,097.7**	**1,016.9**	**961.2**	**924.7**	**1,001.6**
CO_2	931.0	1,213.9	1,080.9	1,001.6	946.6	910.9	986.7
CH_4	5.4	4.4	5.4	4.9	4.3	4.2	5.0
N_2O	7.7	11.6	11.4	10.5	10.3	9.6	10.0
Commercial	**773.6**	**1,041.6**	**950.3**	**919.7**	**877.1**	**849.6**	**868.5**
CO_2	765.9	1,029.9	938.5	908.5	866.0	839.0	858.0
CH_4	1.2	1.4	1.5	1.6	1.6	1.6	1.6

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

[13] 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.

[14] U.S. Territories consumption data that are obtained from EIA are only available at the aggregate level and cannot be broken out by end-use sector. The distribution of emissions to each end-use sector for the 50 states does not apply to territories data.

N_2O	6.5	10.4	10.3	9.6	9.5	9.0	8.9
U.S. Territories[a]	**27.7**	**49.9**	**41.5**	**41.5**	**41.5**	**41.5**	**41.5**
Total	**4,828.7**	**5,829.7**	**5,250.5**	**5,092.8**	**5,001.2**	**4,948.2**	**5,087.2**

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

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

Stationary Combustion

The direct combustion of fuels by stationary sources in the electric power, 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. The CH_4 and N_2O emissions are estimated by applying a "bottom-up" methodology that utilizes facility-specific technology and fuel use data reported to EPA's Acid Rain Program (EPA 2020a) (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 use 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	2014	2015	2016	2017	2018
Electric Power	**1,820.0**	**2,400.0**	**2,037.1**	**1,900.6**	**1,808.9**	**1,732.0**	**1,752.8**
Coal	1,546.5	1,982.8	1,568.6	1,351.4	1,242.0	1,207.1	1,152.9
Natural Gas	175.4	318.9	442.9	525.2	545.0	505.6	577.4
Fuel Oil	97.5	97.9	25.3	23.7	21.4	18.9	22.2
Geothermal	0.5	0.5	0.4	0.4	0.4	0.4	0.4
Industrial	**857.0**	**850.1**	**812.9**	**801.3**	**801.4**	**805.0**	**833.2**
Coal	155.2	115.3	76.0	66.3	59.2	54.4	49.8
Natural Gas	408.5	388.6	467.0	464.4	474.8	485.8	514.8
Fuel Oil	293.3	346.2	269.9	270.5	267.4	264.8	268.6
Commercial	**228.2**	**226.9**	**232.8**	**245.4**	**232.3**	**232.8**	**246.5**
Coal	12.0	9.3	3.8	3.0	2.3	2.0	1.8
Natural Gas	142.0	162.9	189.2	175.4	170.5	173.2	192.6
Fuel Oil	74.2	54.7	39.8	67.1	59.5	57.6	52.1
Residential	**338.2**	**357.9**	**346.8**	**317.8**	**293.1**	**293.8**	**337.3**
Coal	3.0	0.8	NO	NO	NO	NO	NO
Natural Gas	237.8	262.2	277.7	252.7	238.4	241.5	273.7
Fuel Oil	97.4	94.9	69.1	65.1	54.8	52.3	63.5
U.S. Territories	**27.6**	**49.7**	**41.4**	**41.4**	**41.4**	**41.4**	**41.4**
Coal	0.6	3.0	4.0	4.0	4.0	4.0	4.0
Natural Gas	NO	1.3	3.0	3.0	3.0	3.0	3.0
Fuel Oil	26.9	45.4	34.3	34.3	34.3	34.3	34.3
Total	**3,270.9**	**3,884.5**	**3,471.1**	**3,306.5**	**3,177.1**	**3,105.0**	**3,211.2**

Note: Totals may not sum due to independent rounding.

NO (Not Occurring)

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

Sector/Fuel Type	1990	2005	2014	2015	2016	2017	2018
Electric Power	**0.4**	**0.9**	**1.1**	**1.2**	**1.2**	**1.1**	**1.2**
Coal	0.3	0.4	0.3	0.3	0.2	0.2	0.2
Fuel Oil	+	+	+	+	+	+	+

Natural gas	0.1	0.5	0.8	0.9	0.9	0.9	1.0
Wood	+	+	+	+	+	+	+
Industrial	**1.8**	**1.7**	**1.6**	**1.6**	**1.6**	**1.6**	**1.6**
Coal	0.4	0.3	0.2	0.2	0.2	0.1	0.1
Fuel Oil	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Natural gas	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Wood	1.0	1.0	1.1	1.1	1.0	1.1	1.1
Commercial	**1.1**	**1.1**	**1.1**	**1.2**	**1.2**	**1.2**	**1.2**
Coal	+	+	+	+	+	+	+
Fuel Oil	0.3	0.2	0.1	0.2	0.2	0.2	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	0.6	0.6	0.6	0.6
Residential	**5.2**	**4.1**	**5.0**	**4.5**	**3.9**	**3.8**	**4.5**
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	0.6	0.5	0.5	0.6
Wood	4.1	3.1	4.1	3.7	3.2	3.1	3.7
U.S. Territories	**+**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Coal	+	+	+	+	+	+	+
Fuel Oil	+	0.1	0.1	0.1	0.1	0.1	0.1
Natural Gas	NO	+	+	+	+	+	+
Wood	NO	NO	NO	NO	NO	NO	NO
Total	**8.6**	**7.8**	**8.9**	**8.5**	**7.9**	**7.8**	**8.6**

Note: Totals may not sum due to independent rounding.

+ Does not exceed 0.05 MMT CO_2 Eq.

NO (Not Occurring)

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

Sector/Fuel Type	1990	2005	2014	2015	2016	2017	2018
Electric Power	**20.5**	**30.1**	**28.9**	**26.5**	**26.2**	**24.8**	**24.4**
Coal	20.1	28.0	25.7	22.8	22.4	21.2	20.3
Fuel Oil	0.1	0.1	+	+	+	+	+
Natural Gas	0.3	1.9	3.1	3.7	3.8	3.6	4.1
Wood	+	+	+	+	+	+	+
Industrial	**3.1**	**2.9**	**2.7**	**2.6**	**2.6**	**2.6**	**2.6**
Coal	0.7	0.5	0.4	0.3	0.3	0.3	0.2
Fuel Oil	0.5	0.5	0.4	0.4	0.4	0.4	0.4
Natural Gas	0.2	0.2	0.2	0.2	0.3	0.3	0.3
Wood	1.6	1.6	1.7	1.7	1.7	1.7	1.7
Commercial	**0.4**	**0.3**	**0.3**	**0.4**	**0.3**	**0.3**	**0.3**
Coal	0.1	+	+	+	+	+	+
Fuel Oil	0.2	0.1	0.1	0.2	0.2	0.1	0.1
Natural Gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wood	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Residential	**1.0**	**0.9**	**1.0**	**0.9**	**0.8**	**0.8**	**0.9**
Coal	+	+	0.0	0.0	0.0	0.0	NO
Fuel Oil	0.2	0.2	0.2	0.2	0.1	0.1	0.2
Natural Gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wood	0.7	0.5	0.7	0.6	0.5	0.5	0.6
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	**25.1**	**34.3**	**33.0**	**30.5**	**30.0**	**28.6**	**28.4**

Note: Totals may not sum due to independent rounding.

+ Does not exceed 0.05 MMT CO_2 Eq.

NO (Not Occurring)

Electric Power Sector

The process of generating electricity is the largest stationary source of CO_2 emissions in the United States, representing 32 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 total greenhouse gas emissions from electric power, representing 0.1 percent and 1.4 percent, respectively. Electric power also accounted for 34.8 percent of CO_2 emissions from fossil fuel combustion in 2018. Methane and N_2O from electric power represented 10.3 and 55.9 percent of total CH_4 and N_2O emissions from fossil fuel combustion in 2018, respectively.

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. This includes both regulated utilities and non-utilities (e.g., independent power producers, qualifying co-generators, and other small power producers). Electric generation is reported as occurring in other sectors where the producer of the power indicates that its primary business is something other than the production of electricity.[15]

Total GHG emissions from the electric power sector have decreased by 3.4 percent since 1990. The carbon intensity of the electric power sector, in terms of CO_2 Eq. per QBtu, has significantly decreased - by 13 percent - during that same timeframe with the majority of the emissions and carbon intensity decreases occurring in the past decade. This decoupling of electric power generation and the resulting CO_2 emissions is shown below in Figure 3-8. This recent decarbonization of the electric power sector is a result of several key drivers. Coal-fired electric generation (in kilowatt-hours [kWh]) decreased from 54 percent of generation in 1990 to 28 percent in 2018.[16] This corresponded with an increase in natural gas generation 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 29-year period to represent 34 percent of electric power sector generation in 2018 (see Table 3-12). Natural gas has a much lower carbon content than coal, which has led to lower emissions as natural gas replaces coal-powered electricity generation. In 2018, natural gas had a carbon content of 0.0049 kg C/kWh (14.43 MMT C/QBtu) while coal had a carbon content of 0.0089 kg C/kWh (26.09 MMT C/QBtu).

Table 3-12: Electric Power Generation by Fuel Type (Percent)

Fuel Type	1990	2005	2014	2015	2016	2017	2018
Coal	54.1%	51.1%	39.9%	34.2%	31.4%	30.9%	28.4%
Natural Gas	10.7%	17.5%	26.3%	31.6%	32.7%	30.9%	34.1%
Nuclear	19.9%	20.0%	20.3%	20.4%	20.6%	20.8%	20.1%
Renewables	11.3%	8.3%	12.8%	13.0%	14.7%	16.8%	16.7%
Petroleum	4.1%	3.0%	0.7%	0.7%	0.6%	0.5%	0.6%
Other Gases[a]	+%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Net Electricity Generation (Billion kWh)[b]	*2,905*	*3,902*	*3,936*	*3,917*	*3,917*	*3,877*	*4,009*

+ Does not exceed 0.05 percent.

[15] Utilities primarily generate power for the U.S. electric grid for sale to retail customers. Non-utilities typically generate electricity for sale on the wholesale electricity market (e.g., to utilities for distribution and resale to retail customers). Where electricity generation occurs outside the EIA-defined electric power sector, it is typically for the entity's own use.

[16] Values represent electricity *net* generation from the electric power sector (EIA 2019a).

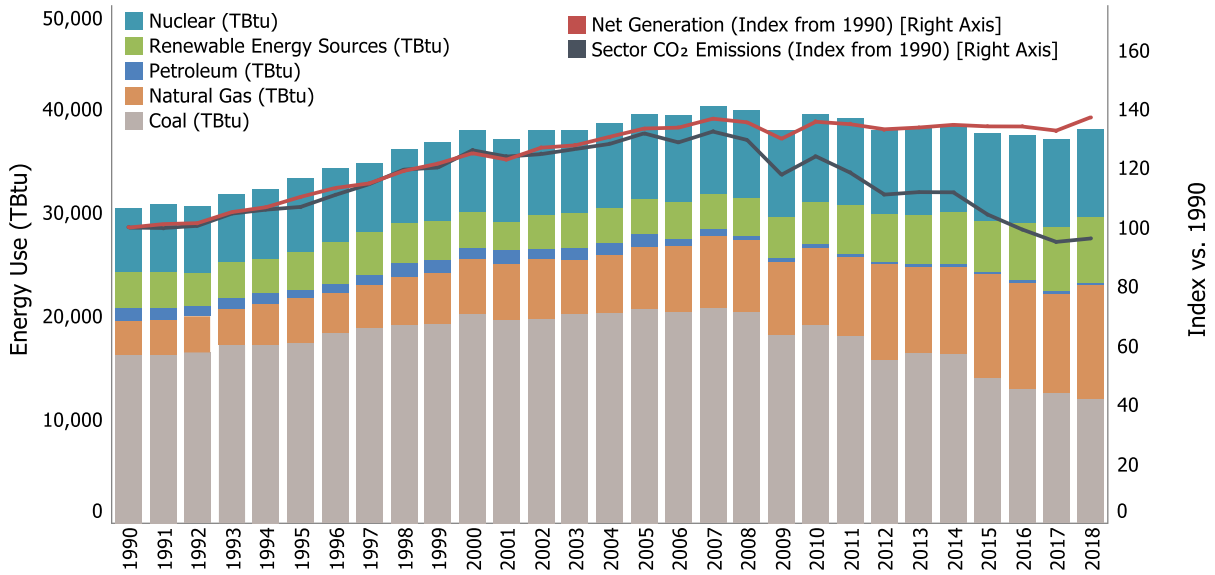
[a] Other gases include blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.

[b] Represents net electricity generation from the electric power sector. Excludes net electricity generation from commercial and industrial combined-heat-and-power and electricity-only plants.

In 2018, CO_2 emissions from the electric power sector increased by 1.2 percent relative to 2017. This increase in CO_2 emissions was a result of an increase in fossil fuels consumed to produce electricity in the electric power sector. Consumption of coal for electric power decreased by 4.5 percent while consumption of natural gas increased 14.2 percent from 2017 to 2018. There has also been a rapid increase in renewable energy electricity generation in the electric power sector in recent years. Electricity generation from renewable sources increased by 3 percent from 2017 to 2018 (see Table 3-12). The decrease in coal-powered electricity generation and increase in renewable energy electricity generation contributed to a decoupling of emissions trends from electric power generation trends over the recent time series (see Figure 3-8).

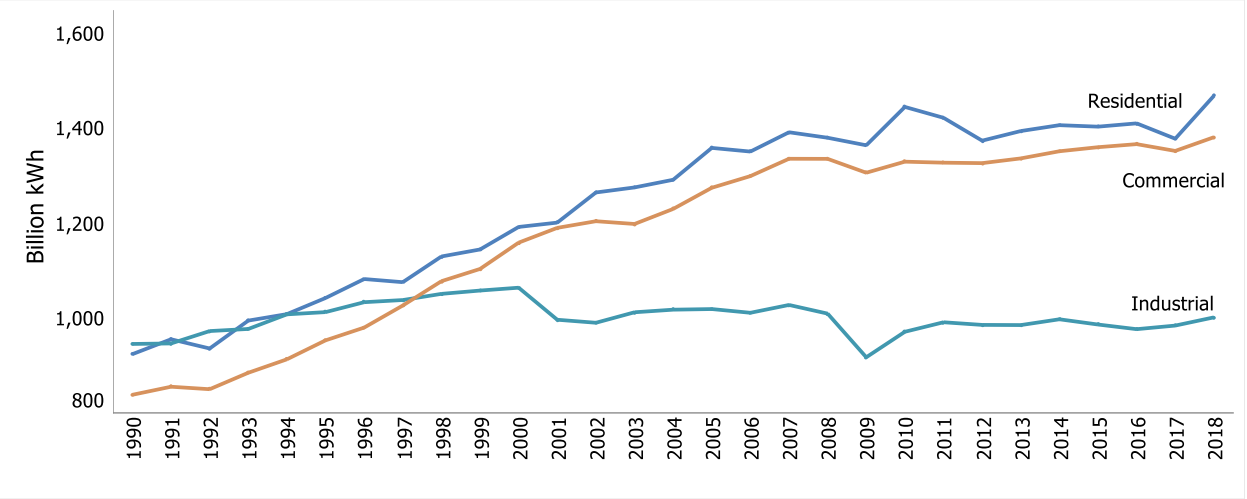
Decreases in natural gas costs and the associated increase in natural gas generation, particularly between 2005 and 2018, was one of the main drivers of the recent fuel switching and decrease in electric power sector carbon intensity. During this time period, the cost of natural gas (in $/MMBtu) decreased by 47 percent while the cost of coal (in $/MMBtu) increased by 78 percent (EIA 2019a). Also, between 1990 and 2018, renewable energy generation (in kWh) from wind and solar energy have increased from 0.1 percent of total generation in 1990 to 8 percent in 2018, which also helped drive the decrease in electric power sector carbon intensity. This decrease in carbon intensity occurred even as total electricity retail sales increased 42 percent, from 2,713 billion kWh in 1990 to 3,860 billion kWh in 2018.

Figure 3-8: Fuels Used in Electric Power Generation (TBtu) and Total Electric Power Sector CO_2 Emissions



Electricity was used primarily in the residential, commercial, and industrial end-use sectors for lighting, heating, electric motors, appliances, electronics, and air conditioning (see Figure 3-9). Note that transportation is an end-use sector as well but is not shown in Figure 3-9 due to the sector's relatively low percentage of electricity use. Table 3-13 provides a break-out of CO_2 emissions from electricity use in the transportation end-use sector.

Figure 3-9: Electric Power Retail Sales by End-Use Sector (Billion kWh)



In 2018, electricity sales to the residential and commercial end-use sectors, as presented in Figure 3-9, increased by 6.6 percent and 2.1 percent relative to 2017, respectively. Electricity sales to the industrial sector in 2018 increased approximately 1.8 percent relative to 2017. Overall, in 2018, the amount of electricity retail sales (in kWh) increased by 3.7 percent relative to 2017.

Industrial Sector

Industrial sector CO_2, CH_4, and N_2O, emissions accounted for 17, 14, and 6 percent of CO_2, CH_4, and N_2O, emissions from fossil fuel combustion, respectively in 2018. 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 use data from EIA, includes activities such as manufacturing, construction, mining, and agriculture. The largest of these activities in terms of energy use 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 2019a; EIA 2009b).

There are many dynamics that impact emissions from the industrial sector including economic activity, changes in the make-up of the industrial sector, changes in the emissions intensity of industrial processes, and weather impacts on heating of industrial buildings.[17] 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) have had a significant effect on industrial emissions.

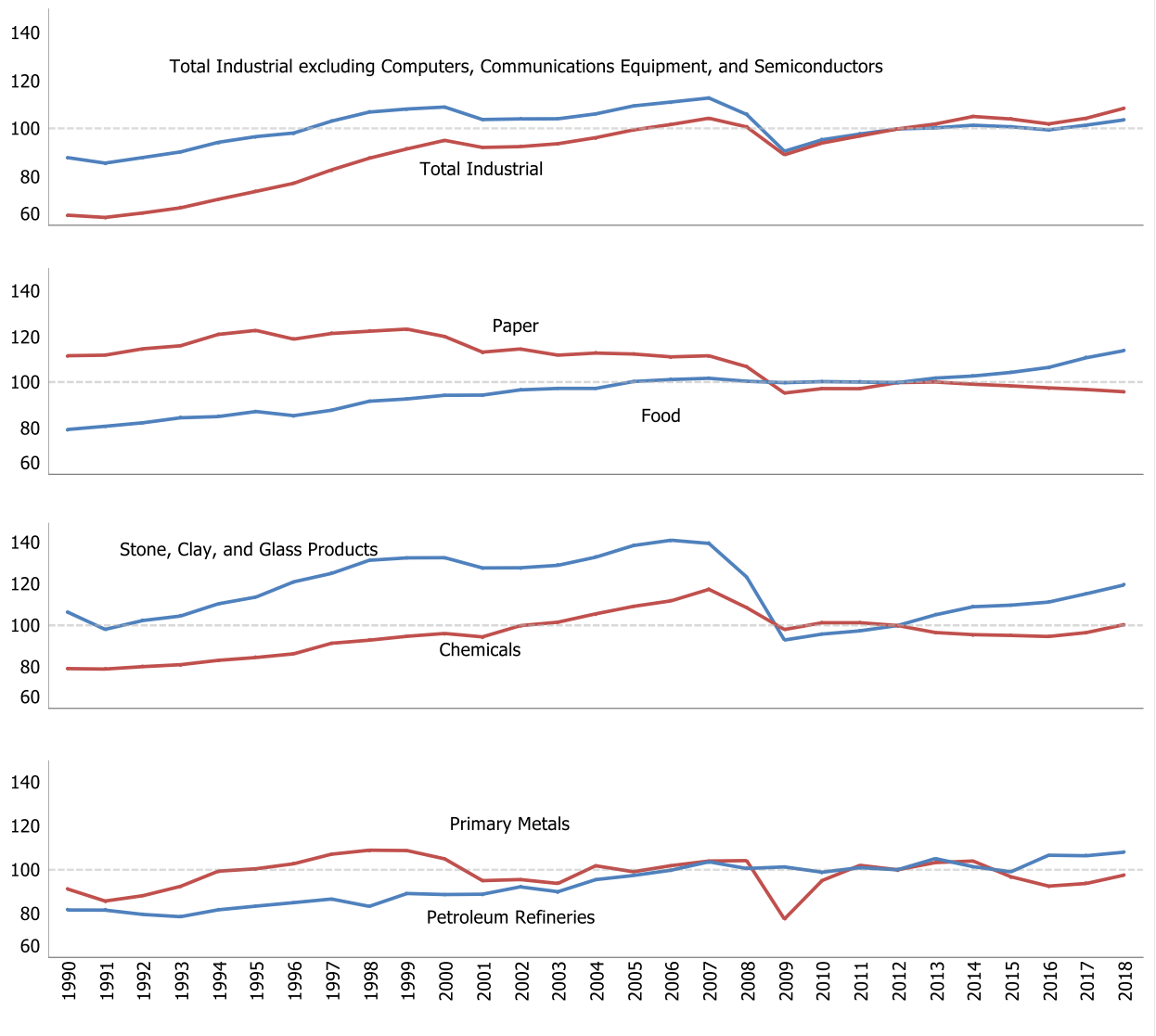
From 2017 to 2018, total industrial production and manufacturing output increased by 3.9 percent (FRB 2019). Over this period, output increased across production indices for Food, Petroleum Refineries, Chemicals, Primary Metals, and Nonmetallic Mineral Products, and decreased slightly for Paper (see Figure 3-10). In 2018, CO_2, CH_4, and N_2O emissions from fossil fuel combustion and electricity use within the industrial end-use sector totaled 1,331.8 MMT CO_2 Eq., a 0.8 percent increase from 2017 emissions.

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 2017 to 2018, the underlying EIA data showed decreased consumption of coal, and increase of natural gas in the industrial sector. The GHGRP data highlights that several industries contributed to these trends, including chemical

[17] 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.

manufacturing; pulp, paper and print; food processing, beverages and tobacco; minerals manufacturing; and agriculture-forest-fisheries.[18]

Figure 3-10: Industrial Production Indices (Index 2012=100)



Despite the growth in industrial output (69 percent) and the overall U.S. economy (99 percent) from 1990 to 2018, CO_2 emissions from fossil fuel combustion in the industrial sector decreased by 2.8 percent over the same time series. A number of factors are assumed to result in decoupling of growth in industrial output from industrial greenhouse gas emissions, for example: (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.

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

Box 3-3: 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 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 2018 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 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.[19]

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.[20] 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 Common Reporting Format (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 2018 time period 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.

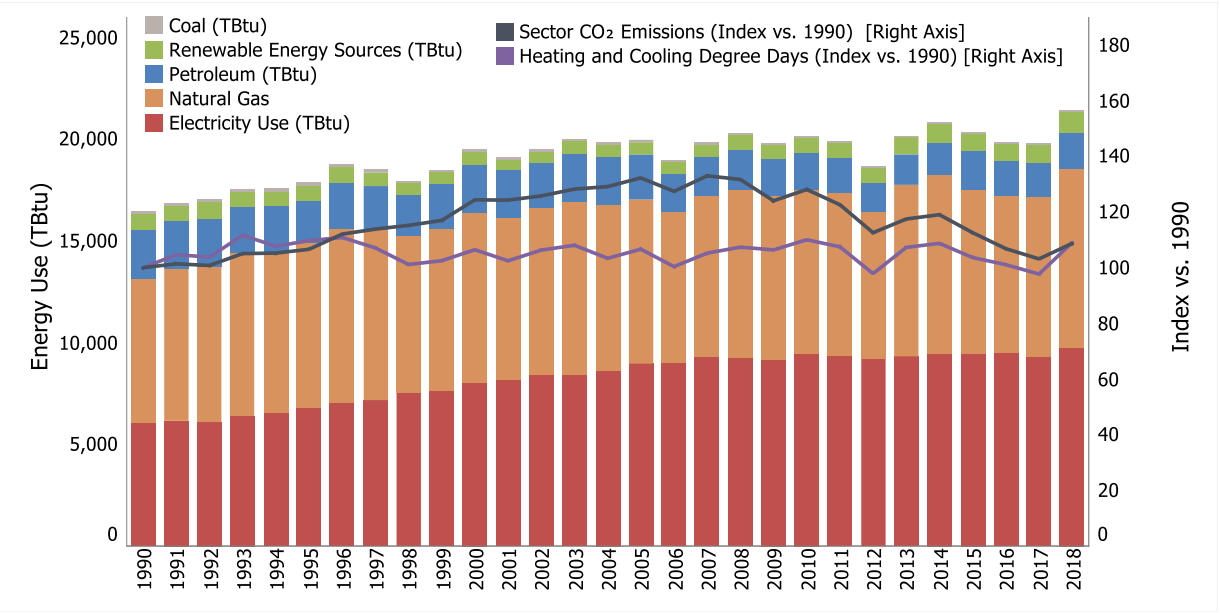
Residential and Commercial Sectors

Emissions from the residential and commercial sectors have increased since 1990. Short-term trends are often correlated with seasonal fluctuations in energy use caused by weather conditions, rather than prevailing economic conditions. Population growth and a trend towards larger houses has led to increasing energy use over the time series, while population migration to warmer areas and improved energy efficiency and building insulation have slowed the increase in energy use in recent years. In the later part of the time series, energy use and emissions begin to decouple due to decarbonization of the electric power sector (see Figure 3-11).

[19] 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>.

[20] See <https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks>.

Figure 3-11: Fuels Used in Residential and Commercial Sectors (TBtu), Heating and Cooling Degree Days, and Total Sector CO_2 Emissions



In 2018 the residential and commercial sectors accounted for 7 and 5 percent of CO_2 emissions from fossil fuel combustion, respectively; 38 and 10 percent of CH_4 emissions from fossil fuel combustion, respectively; and 2 and 1 percent of N_2O emissions from fossil fuel combustion, respectively. Emissions from these sectors were largely due to the direct consumption of natural gas and petroleum products, primarily for heating and cooking needs. Coal consumption was a minor component of energy use for the commercial sector and did not contribute to any energy use in the residential sector. In 2018, total emissions (CO_2, CH_4, and N_2O) from fossil fuel combustion and electricity use within the residential and commercial end-use sectors were 1.001.6 MMT CO_2 Eq. and 868.5 MMT CO_2 Eq., respectively. Total CO_2, CH_4, and N_2O emissions from combined fossil fuel combustion and electricity use within the residential and commercial end-use sectors increased by 8.3 and 2.2 percent from 2017 to 2018, respectively. This trend can be largely be attributed to a 12 percent increase in heating degree days, which led to an increased demand for heating fuel in these sectors.

In 2018, combustion emissions from natural gas consumption represented 81 and 78 percent of the direct fossil fuel CO_2 emissions from the residential and commercial sectors, respectively. Carbon dioxide emissions from natural gas combustion in the residential and commercial sectors in 2018 increased by 13.4 percent and 11.2 percent from 2017 to 2018, 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 by sector, 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 1,843.8 MMT CO_2 Eq. in 2018, which represented 35 percent of CO_2 emissions, 27 percent of CH_4 emissions, and 35 percent of N_2O emissions from fossil fuel combustion, respectively.[21] Fuel purchased in the United States for international aircraft and marine travel accounted for an additional 123.3 MMT CO_2 Eq. in 2018; 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 2018, transportation emissions from fossil fuel combustion rose by 21 percent due, in large part, to increased demand for travel (see Figure 3-12). The number of vehicle miles traveled (VMT) by light-duty motor vehicles (passenger cars and light-duty trucks) increased 46 percent from 1990 to 2018,[22] as a result of a confluence of factors including population growth, economic growth, urban sprawl, and periods of low fuel prices.

From 2017 to 2018, CO_2 emissions from the transportation end-use sector increased by 1.9 percent. The increase in emissions is attributed to an increase in on-road and non-road fuel use, particularly by passenger cars, medium- and heavy-duty trucks, and pipelines.

Commercial aircraft emissions increased between 2017 and 2018, but have decreased 7 percent since 2007 (FAA 2019).[23] Decreases in jet fuel emissions (excluding bunkers) since 2007 are due in part to improved operational efficiency that results in more direct flight routing, improvements in aircraft and engine technologies to reduce fuel burn and emissions, and the accelerated retirement of older, less fuel-efficient aircraft.

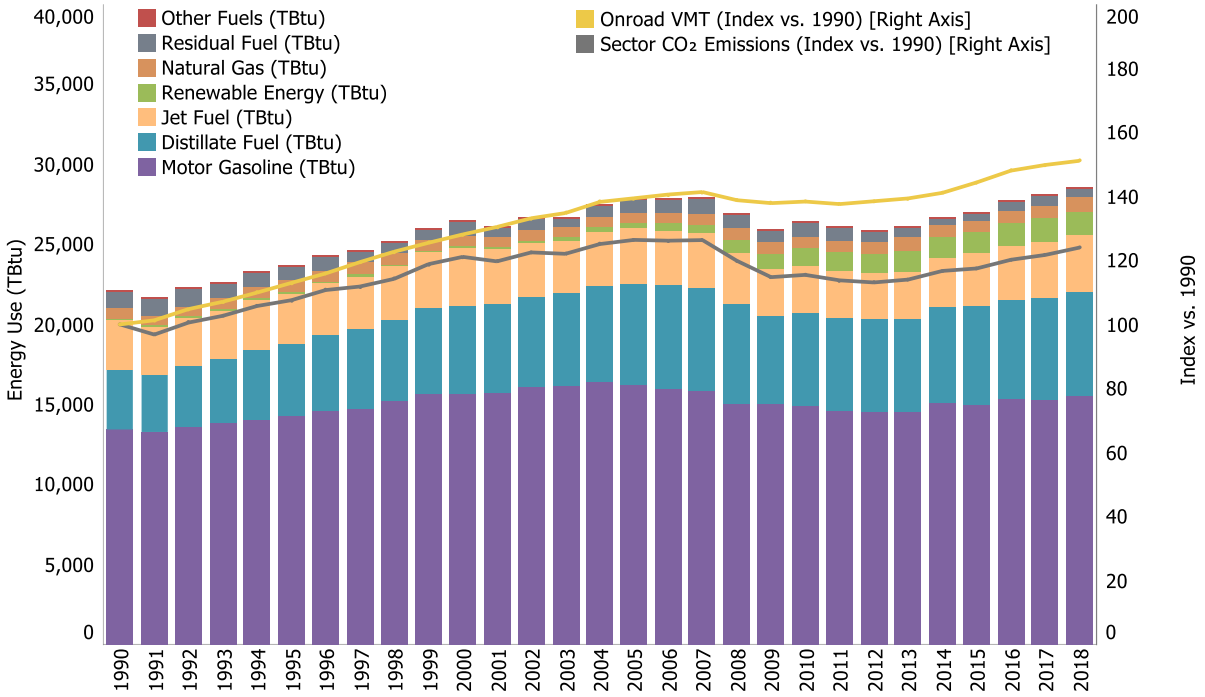
Almost all of the energy consumed for transportation was supplied by petroleum-based products, with more than half being related to gasoline consumption in automobiles and other highway vehicles. Other fuel uses, especially diesel fuel for freight trucks and jet fuel for aircraft, accounted for the remainder. The primary driver of transportation-related emissions was CO_2 from fossil fuel combustion, which increased by 24 percent from 1990 to 2018. Annex 3.2 presents the total emissions from all transportation and mobile sources, including CO_2, CH_4, N_2O and HFCs.

[21] 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.

[22] VMT estimates are based on data from FHWA Highway Statistics Table VM-1 (FHWA 1996 through 2018). 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 2018 time period. In absence of these method changes, light-duty VMT growth between 1990 and 2018 would likely have been even higher.

[23] Commercial aircraft, as modeled in FAA's AEDT (FAA 2019), consists of passenger aircraft, cargo, and other chartered flights.

Figure 3-12: Fuels Used in Transportation Sector (TBtu), Onroad VMT, and Total Sector CO_2 Emissions



Notes: Distillate fuel, residual fuel, and jet fuel include adjustments for international bunker fuels. Distillate fuel and motor gasoline include adjustments for the sectoral allocation of these fuels.
Source: Information on fuel consumption was obtained from EIA (2019a).

Transportation Fossil Fuel Combustion CO_2 Emissions

Domestic transportation CO_2 emissions increased by 24 percent (353.3 MMT CO_2) between 1990 and 2018, an annualized increase of 0.8 percent. Among domestic transportation sources in 2018, 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 12 percent. See Table 3-13 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.[24] Ethanol consumption by the transportation sector has increased from 0.7 billion gallons in 1990 to 13.6 billion gallons in 2018, while biodiesel consumption has increased from 0.01 billion gallons in 2001 to 1.9 billion gallons in 2018. For additional information, see Section 3.11 on biofuel consumption at the end of this chapter and Table A-98 in Annex 3.2.

Carbon dioxide emissions from passenger cars and light-duty trucks totaled 1,069.5 MMT CO_2 in 2018. This is an increase of 16 percent (145.0 MMT CO_2) from 1990 due, in large part, to increased demand for travel as fleet-wide

[24] 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>.

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 2018). Carbon dioxide emissions from passenger cars and light-duty trucks peaked at 1,151.5 MMT CO_2 in 2004, and since then have declined about 7 percent. The decline in new light-duty vehicle fuel economy between 1990 and 2004 (Figure 3-13) is 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,[25] then grew at a faster rate until 2016 (2.6 percent from 2014 to 2015, and 2.5 percent from 2015 to 2016). Since 2016, the rate of light-duty VMT growth has slowed to less than one percent each year. Average new vehicle fuel economy has increased almost every year since 2005, while the light-duty truck share decreased to about 33 percent in 2009 and has since varied from year to year between 36 and 48 percent. Light-duty truck share is about 48 percent of new vehicles in model year 2018 (EPA 2019b). See Annex 3.2 for data by vehicle mode and information on VMT and the share of new vehicles (in VMT).

Medium- and heavy-duty truck CO_2 emissions increased by 87 percent from 1990 to 2018. This increase was largely due to a substantial growth in medium- and heavy-duty truck VMT, which increased by 113 percent between 1990 and 2018.[26] Carbon dioxide from the domestic operation of commercial aircraft increased by 18 percent (19.7 MMT CO_2) from 1990 to 2018.[27] Across all categories of aviation, excluding international bunkers, CO_2 emissions decreased by 7 percent (13.5 MMT CO_2) between 1990 and 2018.[28] This includes a 66 percent (23.2 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 3-14 and Table 3-15 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.

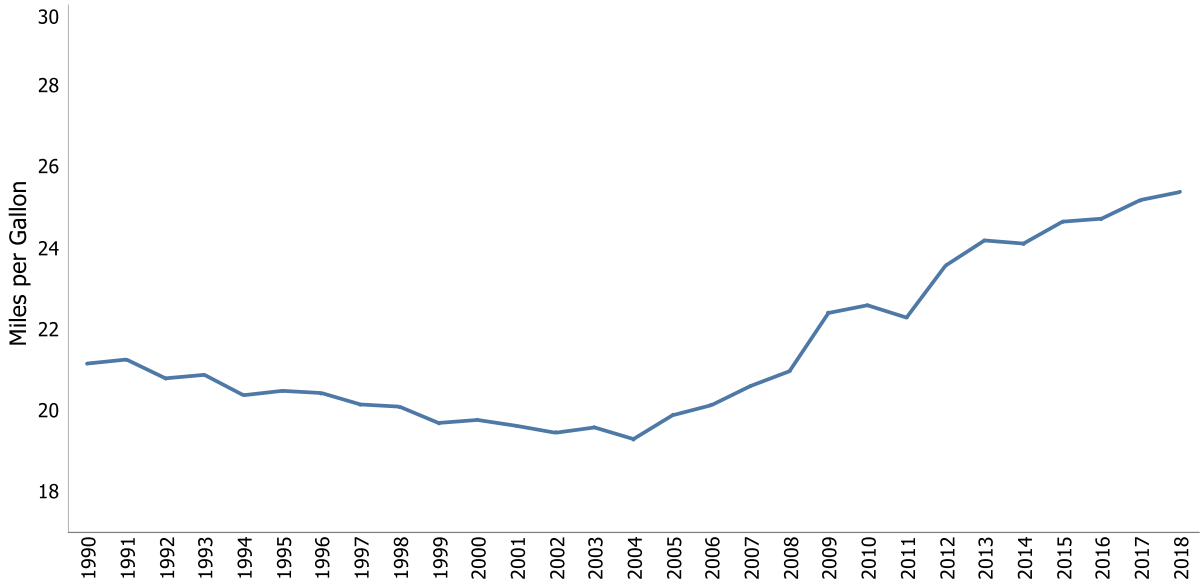
[25] VMT estimates are based on data from FHWA Highway Statistics Table VM-1 (FHWA 1996 through 2018). In 2007 and 2008 light-duty VMT decreased 3.0 percent and 2.3 percent, respectively. Note that the decline in light-duty VMT from 2006 to 2007 is due at least in part to a change in FHWA's methods for 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 2018 time period. In absence of these method changes, light-duty VMT growth between 2006 and 2007 would likely have been higher.

[26] While FHWA data shows consistent growth in medium- and heavy-duty truck VMT over the 1990 to 2018 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 2018 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.

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

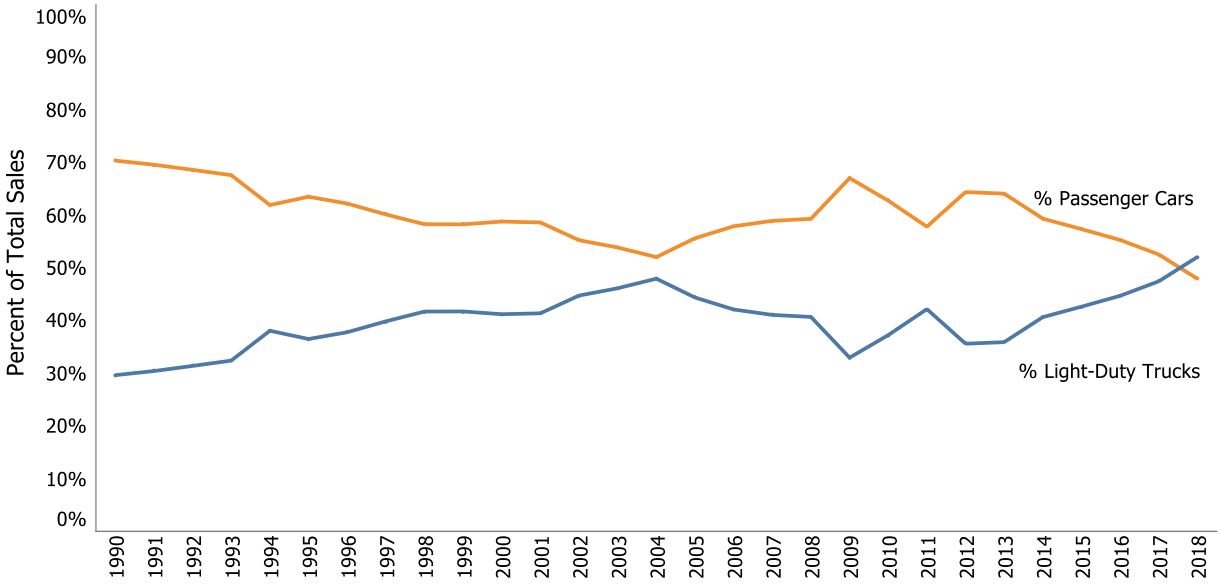
[28] Includes consumption of jet fuel and aviation gasoline. Does not include aircraft bunkers, which are not included in national emission totals, in line with IPCC methodological guidance and UNFCCC reporting obligations.

Figure 3-13: Sales-Weighted Fuel Economy of New Passenger Cars and Light-Duty Trucks, 1990–2018 (miles/gallon)



Source: EPA (2019b).

Figure 3-14: Sales of New Passenger Cars and Light-Duty Trucks, 1990–2018 (Percent)



Source: EPA (2019b).

Table 3-13: CO_2 Emissions from Fossil Fuel Combustion in Transportation End-Use Sector (MMT CO_2 Eq.)

Fuel/Vehicle Type	1990	2005	2014[a]	2015[a]	2016[a]	2017[a]	2018[a]
Gasoline[b]	**958.9**	**1,152.7**	**1,077.4**	**1,070.0**	**1,095.3**	**1,091.7**	**1,107.7**
Passenger Cars	604.3	638.6	730.2	732.0	744.9	744.2	756.0
Light-Duty Trucks	300.6	464.6	292.2	283.5	294.6	290.9	293.7
Medium- and Heavy-Duty Trucks[c]	37.7	33.9	39.8	39.3	40.4	41.2	42.3
Buses	0.3	0.4	0.9	0.9	0.9	1.0	1.0
Motorcycles	1.7	1.6	3.8	3.7	3.8	3.7	3.8
Recreational Boats[d]	14.3	13.8	10.6	10.6	10.7	10.7	10.8
Distillate Fuel Oil (Diesel)[b]	**262.9**	**457.5**	**439.9**	**452.2**	**449.2**	**463.2**	**474.5**
Passenger Cars	7.9	4.2	4.1	4.2	4.2	4.3	4.3
Light-Duty Trucks	11.5	25.8	13.6	13.7	13.9	13.9	14.0
Medium- and Heavy-Duty Trucks[c]	190.5	360.2	354.7	362.4	365.2	377.5	386.2
Buses	8.0	10.6	16.6	16.9	16.5	17.7	19.0
Rail	35.5	45.5	41.2	39.3	35.9	37.1	38.9
Recreational Boats[d]	2.7	2.8	2.5	2.6	2.7	2.7	2.8
Ships and Non-Recreational Boats[e]	6.8	8.4	7.3	13.0	10.8	10.0	9.3
International Bunker Fuels[f]	*11.7*	9.4	6.1	8.4	8.7	9.0	9.9
Jet Fuel	**184.2**	**189.3**	**148.4**	**157.6**	**166.0**	**171.8**	**172.3**
Commercial Aircraft[g]	109.9	132.7	115.2	119.0	120.4	128.0	129.6
Military Aircraft	35.0	19.4	14.0	13.5	12.3	12.2	11.8
General Aviation Aircraft	39.4	37.3	19.2	25.1	33.4	31.5	30.9
International Bunker Fuels[f]	*38.0*	60.1	69.6	71.9	74.1	77.7	80.8
International Bunker Fuels from Commercial Aviation	*30.0*	55.6	66.3	68.6	70.8	74.5	77.7
Aviation Gasoline	**3.1**	**2.4**	**1.5**	**1.5**	**1.4**	**1.4**	**1.5**
General Aviation Aircraft	3.1	2.4	1.5	1.5	1.4	1.4	1.5
Residual Fuel Oil	**22.6**	**19.3**	**5.8**	**4.2**	**12.9**	**16.5**	**13.9**
Ships and Boats[e]	22.6	19.3	5.8	4.2	12.9	16.5	13.9
International Bunker Fuels[f]	*53.7*	43.6	27.7	30.6	33.8	33.4	31.4
Natural Gas[j]	**36.0**	**33.1**	**40.2**	**39.4**	**40.1**	**42.3**	**50.2**
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+
Medium- and Heavy-Duty Trucks	+	+	+	+	+	+	+
Buses	+	0.6	0.8	0.9	0.8	0.9	0.9
Pipeline[h]	36.0	32.4	39.4	38.5	39.2	41.3	49.2
LPG[j]	**1.4**	**1.7**	**0.4**	**0.4**	**0.4**	**0.4**	**0.5**
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	0.2	0.3	0.1	0.1	0.1	0.1	0.1
Medium- and Heavy-Duty Trucks[c]	1.1	1.3	0.3	0.3	0.3	0.3	0.3
Buses	0.1	0.1	0.1	+	0.1	0.1	0.1
Electricity[i]	**3.0**	**4.7**	**4.4**	**4.3**	**4.2**	**4.3**	**4.7**
Passenger Cars	0	0	0.4	0.5	0.6	0.8	1.2
Light-Duty Trucks	0	0	+	+	0.1	0.1	0.2
Buses	0	0	+	+	+	+	+
Rail	3.0	4.7	4.0	3.7	3.5	3.4	3.4
Total[k]	**1,472.1**	**1,860.8**	**1,718.2**	**1,729.5**	**1,769.5**	**1,791.6**	**1,825.4**

Total (Including Bunkers)[f]	**1,575.6**	**1,974.0**	**1,821.6**	**1,840.4**	**1,886.1**	**1,911.7**	**1,947.5**
Biofuels-Ethanol[i]	*4.1*	21.6	74.0	74.2	76.9	77.7	78.6
Biofuels-Biodiesel[i]	*+*	0.9	13.3	14.1	19.6	18.7	17.9

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.

+ 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 2018 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-27 and VM-1 (FHWA 1996 through 2018). 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 2017). TEDB data for 2018 has not been published yet, therefore 2017 data are 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 MOVES2014b for years 1999 through 2018.

[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 Aviation Environmental Design Tool (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 3.11 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 (2019b). Prior to the 1990 to 2015 Inventory, data from DOE TEDB were 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 1990 to 2016 Inventory and apply to the 1990 to 2018 time period.

[k] Includes emissions from rail electricity.

[l] Electricity consumption by passenger cars, light-duty trucks (SUVs), and buses is based on plug-in electric vehicle sales and engine efficiency data, as outlined in Browning (2018a). In prior Inventory years, CO_2 emissions from electric vehicle charging were allocated to the residential and commercial sectors. They are now allocated to the transportation sector. These changes apply to the 2010 through 2018 time period.

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;[29] 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.).[30] Annex 3.2 includes a summary of all emissions from

[29] 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.

[30] 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-

both transportation and mobile sources. Table 3-14 and Table 3-15 provide mobile fossil fuel CH_4 and N_2O emission estimates in MMT CO_2 Eq.[31]

Mobile combustion was responsible for a small portion of national CH_4 emissions (0.5 percent) and was the fourth largest source of national N_2O emissions (3.5 percent). From 1990 to 2018, mobile source CH_4 emissions declined by 76 percent, to 3.1 MMT CO_2 Eq. (125 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 64 percent, to 15.2 MMT CO_2 Eq. (51 kt N_2O). Earlier generation control technologies initially resulted in higher N_2O emissions, causing a 30 percent increase in N_2O emissions from mobile sources between 1990 and 1997. Improvements in later-generation emission control technologies have reduced N_2O emissions, resulting in a 72 percent decrease in mobile source N_2O emissions from 1997 to 2018 (Figure 3-15). Overall, CH_4 and N_2O emissions were predominantly from gasoline-fueled passenger cars and light-duty trucks and non-highway sources. See Annex 3.2 for data by vehicle mode and information on VMT and the share of new vehicles (in VMT).

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

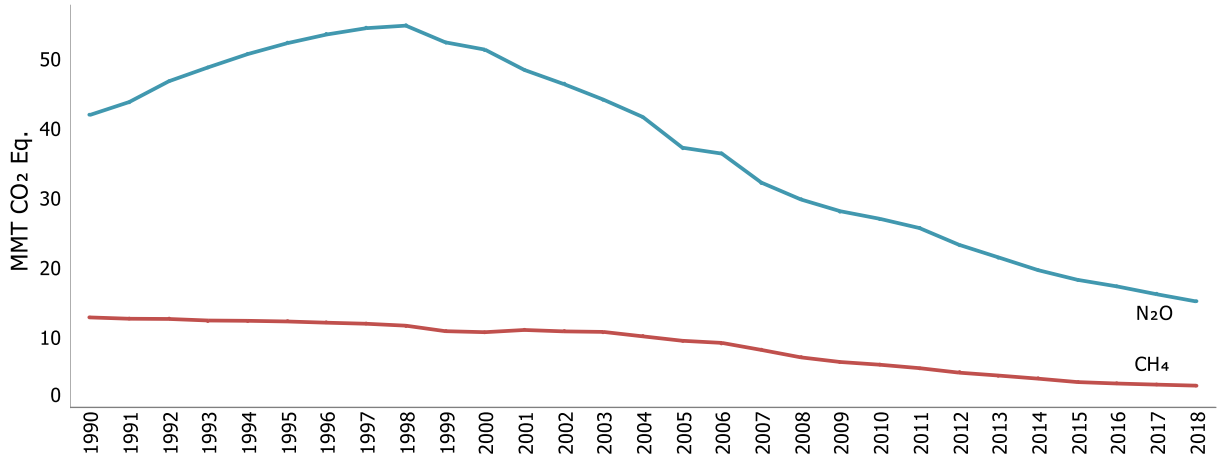


Table 3-14: CH_4 Emissions from Mobile Combustion (MMT CO_2 Eq.)

Fuel Type/Vehicle Type[a]	1990	2005	2014	2015	2016	2017	2018
Gasoline On-Road[b]	**5.2**	**2.2**	**1.1**	**1.0**	**0.9**	**0.8**	**0.7**
Passenger Cars	3.2	1.3	0.7	0.6	0.6	0.5	0.5
Light-Duty Trucks	1.7	0.8	0.3	0.2	0.2	0.2	0.2
Medium- and Heavy-Duty Trucks and Buses	0.3	0.1	0.1	0.1	0.0	0.0	0.0
Motorcycles	+	+	+	+	+	+	+
Diesel On-Road[b]	**+**	**+**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Passenger Cars	+	+	+	+	+	+	+

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.

[31] See Annex 3.2 for a complete time series of emission estimates for 1990 through 2018.

Light-Duty Trucks	+	+	+	+	+	+	+
Medium- and Heavy-Duty Trucks and Buses	+	+	+	+	0.1	0.1	0.1
Alternative Fuel On-Road	**+**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**
Non-Road[c]	**7.7**	**7.2**	**2.8**	**2.4**	**2.3**	**2.2**	**2.1**
Ships and Boats	0.6	0.5	0.3	0.3	0.3	0.3	0.3
Rail	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Aircraft	0.1	0.1	+	+	+	+	+
Agricultural Equipment[d]	0.6	0.6	0.2	0.1	0.1	0.1	0.1
Construction/Mining Equipment[e]	0.9	1.0	0.6	0.5	0.4	0.4	0.4
Other[f]	5.5	4.9	1.6	1.5	1.4	1.3	1.3
Total	**12.9**	**9.6**	**4.1**	**3.6**	**3.4**	**3.3**	**3.1**

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 2018 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.

+ 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 2018). 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 2017). TEDB data for 2018 has not been published yet, therefore 2017 data are used as a proxy.

[c] Rail emissions do not include emissions from electric powered locomotives. Class II and Class III diesel consumption data for 2014-2018 is estimated by applying the historical average fuel usage per carload factor to the annual number of carloads. Intercity rail diesel consumption data for 2017 and 2018 is not available yet, therefore 2016 data are used as a proxy. Commuter rail diesel consumption data for 2018 is not available yet, therefore 2017 data are used as a proxy.

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

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

[f] "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.

Table 3-15: N_2O Emissions from Mobile Combustion (MMT CO_2 Eq.)

Fuel Type/Vehicle Type[a]	1990	2005	2014	2015	2016	2017	2018
Gasoline On-Road[b]	**37.5**	**31.8**	**13.3**	**11.6**	**10.2**	**8.7**	**7.3**
Passenger Cars	24.1	17.3	9.0	8.0	7.0	6.0	5.1
Light-Duty Trucks	12.8	13.6	3.8	3.1	2.7	2.3	1.9
Medium- and Heavy-Duty Trucks and Buses	0.5	0.9	0.5	0.4	0.4	0.3	0.3
Motorcycles	+	+	+	+	+	+	+
Diesel On-Road[b]	**0.2**	**0.3**	**1.9**	**2.2**	**2.4**	**2.6**	**2.9**
Passenger Cars	+	+	+	+	0.1	0.1	0.1
Light-Duty Trucks	+	+	0.1	0.1	0.1	0.1	0.1
Medium- and Heavy-Duty Trucks and Buses	0.2	0.3	1.8	2.0	2.2	2.4	2.7
Alternative Fuel On-Road	**+**	**+**	**0.1**	**0.1**	**0.2**	**0.2**	**0.2**
Non-Road	**4.4**	**5.2**	**4.5**	**4.5**	**4.7**	**4.9**	**4.9**
Ships and Boats	0.6	0.6	0.3	0.4	0.5	0.5	0.5

Rail[c]	0.3	0.4	0.4	0.4	0.3	0.4	0.4
Aircraft	1.7	1.8	1.4	1.5	1.5	1.6	1.6
Agricultural Equipment[d]	0.5	0.6	0.6	0.6	0.6	0.5	0.5
Construction/Mining Equipment[e]	0.6	1.0	0.8	0.8	0.8	0.9	0.9
Other[f]	0.6	0.9	1.0	1.0	1.0	1.0	1.0
Total	**42.1**	**37.4**	**19.8**	**18.4**	**17.5**	**16.3**	**15.3**

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 2018 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.

+ 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 2018). 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 2017). TEDB data for 2018 has not been published yet, therefore 2016 data are used as a proxy.

[c] Rail emissions do not include emissions from electric powered locomotives. Class II and Class III diesel consumption data for 2014-2017 is estimated by applying the historical average fuel usage per carload factor to the annual number of carloads. Intercity rail diesel consumption data for 2017 and 2018 is not available yet, therefore 2016 data are used as a proxy. Commuter rail diesel consumption data for 2018 is not available yet, therefore 2017 data are used as a proxy.

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

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

[f] "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.

CO_2 from Fossil Fuel Combustion

Methodology

CO_2 emissions from fossil fuel combustion are estimated in line with a Tier 2 method described by the IPCC in the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC 2006) with some exceptions as discussed below.[32] 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), primary fuel type (e.g., coal, petroleum, gas), and secondary fuel category (e.g., motor gasoline, distillate fuel oil). 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 2019a). EIA data includes fuel consumption statistics from the 50 U.S. states and the District of Columbia, including tribal lands. 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 2017).[33]

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

[33] 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 41.4 MMT CO_2 Eq. in 2018.

For consistency of reporting, the IPCC has recommended that countries report energy data using the International Energy Agency (IEA) reporting convention and/or IEA data. Data in the IEA format are presented "top down"—that is, energy consumption for fuel types and categories are estimated from energy production data (accounting for imports, exports, stock changes, and losses). The resulting quantities are referred to as "apparent consumption." The data collected in the United States by EIA on an annual basis and used in this Inventory are predominantly from mid-stream or conversion energy consumers such as refiners and electric power generators. These annual surveys are supplemented with end-use energy consumption surveys, such as the Manufacturing Energy Consumption Survey, that are conducted on a 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.[34]

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).[35]

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 2018), Coffeyville (2012), U.S. Census Bureau (2001 through 2011), EIA (2020a, 2019a, 2019d), USAA (2008 through 2018), USGS (1991 through 2015a), (USGS 2018b), USGS (2014 through 2019b), USGS (2014 through 2017), USGS (1995 through 2013), USGS (1995, 1998, 2000, 2001, 2002, 2007), USGS (2019), USGS (1991 through 2015c), USGS (1991 through 2017), USGS (2014 through 2019a), USGS (1996 through 2013), USGS (1991 through 2015b), USGS (2020), USGS (1991 through 2015c).[36]

3. *Adjust for biofuels, conversion of fossil fuels, and exports of CO_2.* Fossil fuel consumption estimates are adjusted downward to exclude (1) fuels with biogenic origins, (2) fuels created from other fossil fuels, and (3) exports of CO_2. Carbon dioxide emissions from ethanol added to motor gasoline and biodiesel added to diesel fuel are not included specifically in summing energy sector totals. Net carbon fluxes from changes in biogenic carbon reservoirs are accounted for in the estimates for LULUCF, therefore, fuel consumption estimates are adjusted to remove ethanol and biodiesel.[37] Synthetic natural gas is created from industrial coal and is currently included in EIA statistics for coal. Therefore, synthetic natural gas is subtracted from coal consumption statistics.[38] 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 coal 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 were collected from EIA (2019a), data for synthetic natural gas were collected from EIA (2019d), and data for CO_2 exports were collected from the Eastman

[34] 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.

[35] 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.

[36] 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.

[37] Natural gas energy statistics from EIA (2019a) are already adjusted downward to account for biogas in natural gas.

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

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 were adjusted to match the value obtained from the bottom-up analysis. As the total distillate and motor gasoline consumption estimate from EIA are considered to be accurate at the national level, the distillate and motor gasoline consumption totals for the residential, commercial, and industrial sectors were adjusted proportionately. The data sources used in the bottom-up analysis of transportation fuel consumption include AAR (2008 through 2018), Benson (2002 through 2004), DOE (1993 through 2017), EIA (2007), EIA (1991 through 2019), EPA (2018), and FHWA (1996 through 2018).[39]

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 were provided by EIA (2019a).

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 Carbon content).[40] 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 2019) supplied data on military jet fuel and marine fuel use. Commercial jet fuel use was obtained from FAA (2019); residual and distillate fuel use for civilian marine bunkers was obtained from DOC (1991 through 2019) for 1990 through 2001 and 2007 through 2018, and DHS (2008) for 2003 through 2006.[41] 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 3.10 – International Bunker Fuels.

7. *Determine the total Carbon 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 Carbon 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 Carbon content coefficients developed for the GHGRP (EPA 2010). A discussion of the methodology used to develop the Carbon content coefficients are presented in Annexes 2.1 and 2.2.

[39] 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 2018).

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

[41] Data for 2002 were interpolated due to inconsistencies in reported fuel consumption data.

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 Carbon 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). Carbon emissions were multiplied by the molecular-to-atomic weight ratio of CO_2 to C (44/12) to obtain total CO_2 emitted from fossil fuel combustion in million metric tons (MMT).

9. *Allocate transportation emissions by vehicle type.* This report provides a more detailed accounting of emissions from transportation because it is such a large consumer of fossil fuels in the United States. For fuel types other than jet fuel, fuel consumption data by vehicle type and transportation mode were used to allocate emissions by fuel type calculated for the transportation end-use sector. Heat contents and densities were obtained from EIA (2019a) and USAF (1998).[42]

    - For on-road vehicles, annual estimates of combined motor gasoline and diesel fuel consumption by vehicle category were obtained from FHWA (1996 through 2018); for each vehicle category, the percent gasoline, diesel, and other (e.g., CNG, LPG) fuel consumption are estimated using data from DOE (1993 through 2017). [43,44]

    - For non-road vehicles, activity data were obtained from AAR (2008 through 2018), APTA (2007 through 2017), APTA (2006), BEA (2020), Benson (2002 through 2004), DLA Energy (2019), DOC (1991 through 2019), DOE (1993 through 2017), DOT (1991 through 2018), EIA (2009a), EIA (2019a), EIA (2019f), EIA (1991 through 2018), EPA (2018),[45] 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.

[42] 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.

[43] Data from FHWA's Table VM-1 is used to estimate the share of fuel 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 2017). 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 time period from 2007 through 2015. 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.

[44] Transportation sector natural gas and LPG consumption are based on data from EIA (2019a). In previous Inventory years, data from DOE (1993 through 2017) 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 previous Inventory and apply to the time period from 1990 to 2015.

[45] In 2014, EPA incorporated the NONROAD2008 model into MOVES2014. The current Inventory uses the NONROAD component of MOVES2014b for years 1999 through 2018.

Box 3-4: Carbon Intensity of U.S. Energy Consumption

The amount of C emitted from the combustion of fossil fuels is dependent upon the carbon content of the fuel and the fraction of that C that is oxidized. Fossil fuels vary in their average carbon 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 (see Tables A-42 and A-43 in Annex 2.1 for carbon contents of all fuels). In general, the carbon content per unit of energy of fossil fuels is the highest for coal products, followed by petroleum, and then natural gas. The overall carbon 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 3-16 provides a time series of the carbon intensity of direct emissions for each sector of the U.S. economy. The time series incorporates only the energy from the direct combustion of fossil fuels in each sector. For example, the carbon intensity for the residential sector does not include the energy from or emissions related to the use of electricity for lighting, as it is instead allocated to the electric power sector. For the purposes of maintaining the focus of this section, renewable energy and nuclear energy are not included in the energy totals used in Table 3-16 in order to focus attention on fossil fuel combustion as detailed in this chapter. Looking only at this direct consumption of fossil fuels, the residential sector exhibited the lowest carbon intensity, which is related to the large percentage of its energy derived from natural gas for heating. The carbon 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 Carbon intensity of the transportation sector was closely related to the Carbon content of petroleum products (e.g., motor gasoline and jet fuel, both around 70 MMT CO_2 Eq./QBtu), which were the primary sources of energy. Lastly, the electric power sector had the highest Carbon intensity due to its heavy reliance on coal for generating electricity.

Table 3-16: Carbon Intensity from Direct Fossil Fuel Combustion by Sector (MMT CO_2 Eq./QBtu)

Sector	1990	2005	2014	2015	2016	2017	2018
Residential[a]	57.4	56.6	55.4	55.5	55.1	55.0	55.2
Commercial[a]	59.6	57.7	55.7	57.2	56.8	56.6	56.0
Industrial[a]	64.5	64.5	61.5	61.2	60.8	60.5	60.2
Transportation[a]	71.1	71.4	71.5	71.5	71.5	71.5	71.4
Electric Power[b]	87.3	85.8	81.2	78.1	76.8	77.3	75.5
U.S. Territories[c]	73.0	73.5	72.3	72.2	72.2	72.2	72.2
All Sectors[c]	**73.0**	**73.5**	**70.8**	**69.7**	**69.2**	**69.2**	**68.3**

Note: Excludes non-energy fuel use emissions and consumption.

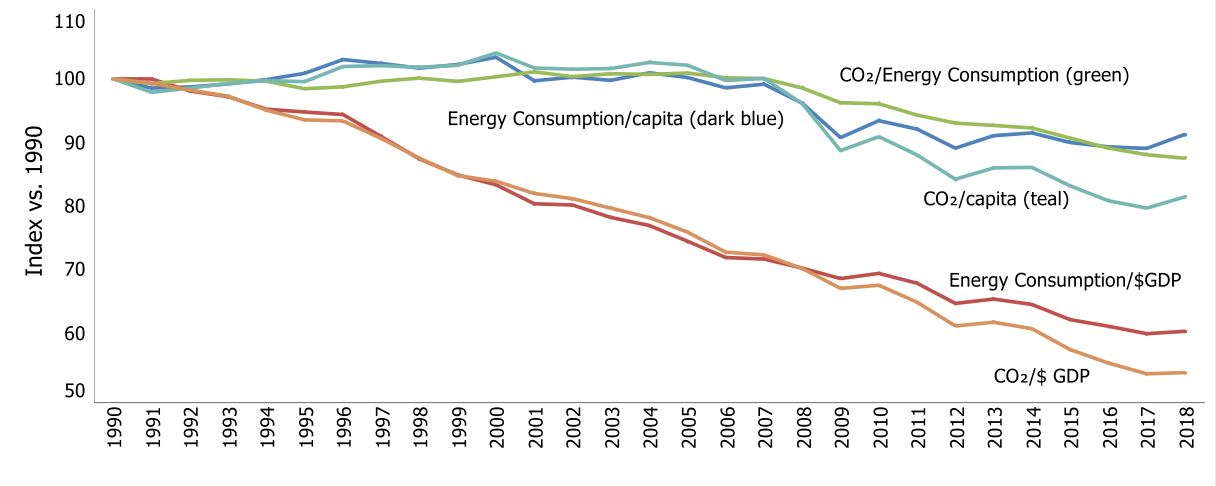
[a] Does not include electricity or renewable energy consumption.

[b] Does not include electricity produced using nuclear or renewable energy.

[c] Does not include nuclear or renewable energy consumption.

For the time period of 1990 through about 2008, the carbon 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 carbon intensity has decreased, reflecting the shift from coal to natural gas in the electric power sector during that time period. Per capita energy consumption fluctuated little from 1990 to 2007, but then started decreasing after 2007 and, in 2018, was approximately 8.7 percent below levels in 1990 (see Figure 3-16). To differentiate these estimates from those of Table 3-16, the carbon 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 2018).

Figure 3-16: U.S. Energy Consumption and Energy-Related CO_2 Emissions Per Capita and Per Dollar GDP



Carbon intensity estimates were developed using nuclear and renewable energy data from EIA (2019a), 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). See also Annex 2.2 for a discussion of uncertainties associated with fuel carbon contents. Even with recent updates to carbon factors for natural gas and coal, the uncertainty estimates are not impacted.

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 3.10 – 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 170 input variables were modeled for CO_2 from energy-related Fossil Fuel Combustion (including about 20 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.[46] Triangular distributions were assigned for the oxidization factors (or combustion efficiencies). The uncertainty ranges were assigned to the input variables based on the data reported in SAIC/EIA (2001) and on conversations with various agency personnel.[47]

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).[48] 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 3-17. Fossil fuel combustion CO_2 emissions in 2018 were estimated to be between 4,919.7 and 5,255.7 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 2 percent below to 4 percent above the 2018 emission estimate of 5,031.8 MMT CO_2 Eq.

[46] 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.

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

[48] 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.

Table 3-17: 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	2018 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]	**1,208.5**	**1,165.5**	**1,322.3**	**-4%**	**9%**
Residential	NO	NE	NE	NE	NE
Commercial	1.8	1.7	2.1	-5%	15%
Industrial	49.8	47.4	57.6	-5%	16%
Transportation	NE	NE	NE	NE	NE
Electric Power	1,152.9	1,107.9	1,263.2	-4%	10%
U.S. Territories	4.0	3.5	4.8	-12%	19%
Natural Gas[b]	**1,611.6**	**1,592.7**	**1,685.3**	**-1%**	**5%**
Residential	273.7	266.1	292.7	-3%	7%
Commercial	192.6	187.1	206.1	-3%	7%
Industrial	514.8	499.1	551.6	-3%	7%
Transportation	50.2	48.7	53.7	-3%	7%
Electric Power	577.4	560.7	606.8	-3%	5%
U.S. Territories	3.0	2.6	3.5	-12%	17%
Petroleum[b]	**2,211.3**	**2,075.5**	**2,338.3**	**-6%**	**6%**
Residential	63.5	60.0	66.9	-6%	5%
Commercial	52.1	49.4	54.6	-5%	5%
Industrial	268.6	210.0	321.1	-22%	20%
Transportation	1,770.5	1,654.4	1,884.6	-7%	6%
Electric Power	22.2	21.2	23.9	-5%	8%
U.S. Territories	34.3	31.7	38.1	-8%	11%
Total (excluding Geothermal)[b]	**5,031.4**	**4,919.2**	**5,255.2**	**-2%**	**4%**
Geothermal	0.4	NE	NE	NE	NE
Total (including Geothermal)[b,c]	**5,031.8**	**4,919.7**	**5,255.7**	**-2%**	**4%**

Note: Totals may not sum due to independent rounding.
NO (Not Occurring)
NE (Not Estimated)
[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.
[b] The low and high estimates for total emissions were calculated separately through simulations and, hence, the low and high emission estimates for the sub-source categories do not sum to total emissions.
[c] Geothermal emissions added for reporting purposes, but an uncertainty analysis was not performed for CO_2 emissions from geothermal production.

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990 through 2018. Details on the emission trends through time are described in more detail in the Methodology section, above. As discussed in Annex 5, data are unavailable to include estimates of CO_2 emissions from any liquid fuel used in pipeline transport or non-hazardous industrial waste incineration, but those emissions are assumed to be insignificant.

QA/QC and Verification

In order to ensure the quality of the CO_2 emission estimates from fossil fuel combustion, general (IPCC Tier 1) and category-specific (Tier 2) Quality Assurance/Quality Control (QA/QC) procedures were implemented consistent with the U.S. Inventory QA/QC plan outlined in Annex 8. 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.

The UNFCCC reporting guidelines require countries to complete a "top-down" reference approach for estimating CO_2 emissions from fossil fuel combustion in addition to their "bottom-up" sectoral methodology. The reference approach (detailed in Annex 4) uses alternative methodologies and different data sources than those contained in this section of the report. The reference approach estimates fossil fuel consumption by adjusting national aggregate fuel production data for imports, exports, and stock changes rather than relying on end-user consumption surveys. The reference approach assumes that once carbon-based fuels are brought into a national economy, they are either saved in some way (e.g., stored in products, kept in fuel stocks, or left unoxidized in ash) or combusted, and therefore the carbon in them is oxidized and released into the atmosphere. In the reference approach, accounting for actual consumption of fuels at the sectoral or sub-national level is not required. One difference between the two approaches is that emissions from carbon that was not stored during non-energy use of fuels are subtracted from the sectoral approach and reported separately (see Section 3.2). These emissions, however, are not subtracted in the reference approach. As a result, the reference approach emission estimates are comparable to those of the sectoral approach, with the exception that the NEU source category emissions are included in the reference approach (see Annex 4 for more details).

Recalculations Discussion

The Energy Information Administration (EIA 2019a) updated energy consumption statistics across the time series relative to the previous Inventory.[49] As a result of updated LPG and fuel ethanol heat contents, EIA updated LPG consumption in the residential, commercial, industrial, and transportation sectors across the time series. EIA also revised sector allocations for propane and total LPGs for 2010 through 2017, and for distillate fuel oil in 2017, which impacted petroleum consumption by sector. EIA revised assumptions for the percentage of fossil fuels consumed for non-combustion use which impacted the nonfuel sequestration statistics, particularly for petroleum coke and residual fuel across the time series relative to the previous Inventory.

EIA also revised 2017 natural gas consumption in all sectors, 2017 kerosene consumption in the residential and commercial sectors, 2009 and 2017 motor gasoline consumption in the commercial, industrial, and transportation sectors, 1995 and 1997 through 2000 asphalt and road oil consumption in the industrial sector, 2017 residual fuel oil and lubricants in the industrial and transportation sectors, 2017 petroleum coke consumption in the industrial sector, 2009 through 2017 distillate fuel oil consumption in the transportation sector, and pentanes plus consumption in the industrial sector across the time series.

To align with EIA's methodology for calculating industrial and commercial motor gasoline consumption, fuel ethanol adjustments to motor gasoline consumption for the period 1990 through 1992 were corrected. To align with EIA's methodology for calculating the amount of biofuel added to diesel fuel, both biodiesel and other renewable diesel fuel were considered; EIA (2019a) data were used for 2009 forward. To improve the time series consistency of distillate fuel oil consumption, data from EIA's Fuel Oil and Kerosene Sales Report (EIA 1991 through 2019) were used across the time series. Previously, distillate fuel oil consumption for the period 1990 through 2002 were obtained from EIA's State Energy Data System (SEDS) (EIA 1990-2002) and 2003 data were provided by EIA (2003).

Revisions to LPG, lubricants, kerosene, jet fuel, distillate fuel, asphalt and road oil, residual fuel oil, petroleum coke, pentanes plus, and motor gasoline consumption resulted in an average annual decrease of 6.6 MMT CO_2 Eq. (0.3 percent) in CO_2 emissions from petroleum. Revisions to natural gas consumption resulted in an increase of 1.0 MMT CO_2 Eq. (0.1 percent) in CO_2 emissions from natural gas in 2017. Overall, these changes resulted in an

[49] Final estimates presented in this Inventory utilize energy statistics from EIA's Monthly Energy Review released in November 2019 (EIA 2019a). At the time of publication of this Inventory report there were no changes to energy statistics reported in later iterations of the Monthly Energy Review.

average annual decrease of 6.6 MMT CO_2 Eq. (0.1 percent) in CO_2 emissions from fossil fuel combustion for the period 1990 through 2017, relative to the previous Inventory.

As discussed in the Recalculations section of Chapter 4.5 – Ammonia Production, the carbon factors used to determine the amount of natural gas used for ammonia feedstock were updated to be consistent with the factors used in the fossil fuel combustion estimates. This update resulted in an annual average change to the amount of natural gas subtracted from total natural gas consumption for energy use calculations of 0.08 percent over the 1990 to 2017 time period.

Planned Improvements

To reduce uncertainty of CO_2 from fossil fuel combustion estimates for U.S. Territories, efforts will be made to improve the quality of the U.S. Territories data, including through work with EIA and other agencies. This improvement 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.[50] In line with UNFCCC reporting guidelines, fuel combustion emissions are included in this chapter, while process emissions are included in the Industrial Processes and Product Use chapter of this report. In examining data from EPA's GHGRP that would be useful to improve the emission estimates for the CO_2 from fossil fuel combustion category, particular attention will also be made to ensure time-series consistency, as the facility-level reporting data from EPA's GHGRP are not available for all inventory years as reported in this Inventory.

Additional analyses will be conducted to align reported facility-level fuel types and IPCC fuel types per the national energy statistics. 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.[51]

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.

In 2016, FHWA changed its methods for estimating the share of gasoline used in on-road and non-road applications, creating a time-series inconsistency in the current Inventory between 2015 and previous years.[52] EPA

[50] See <https://unfccc.int/resource/docs/2013/cop19/eng/10a03.pdf#page=2>.

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

[52] 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>.

has implemented an approach to address this inconsistency. EPA also tested an alternative approach that uses MOVES on-road fuel consumption output to define the percentage of the FHWA consumption totals (from MF-21) that are attributable to on-highway transportation sources, and applying this percentage to the EIA total, thereby defining gasoline consumption from on-highway transportation sources (such that the remainder would be defined as consumption by the industrial and commercial sectors). Results from this testing revealed differences between fuel consumption calculated by MOVES and fuel consumption data from FHWA. Given this inconsistency, no changes have been made to the methodology for estimating motor gasoline consumption for non-road mobile sources.

EPA is also evaluating the methods used to adjust for conversion of fuels and exports of CO_2. EPA is exploring the approach used to account for CO_2 transport, injection, and geologic storage, as part of this there may be changes made to accounting for CO_2 exports. EPA is also exploring the data provided by EIA in terms of tracking supplemental natural gas which may impact the treatment of adjustments for synthetic fuels.

EPA is currently evaluating proposed revisions to gasoline carbon factors used in this report. The current Inventory continues to use NIPER (1990 through 2009) data to determine gasoline composition. NIPER has ceased to exist and the current carbon factors have not been updated since 2010 (for the 1990-2008 Inventory Report). New data and methods are available to estimate gasoline carbon factors over the time series. EPA has started reviewing data and approaches and plans to update the gasoline carbon factors in a future report.

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.

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

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 emission estimates, consumption data for each fuel were obtained from EIA's *Monthly Energy Review* (EIA 2019). 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 2017).[53] Fuel consumption for the industrial sector was adjusted to subtract out mobile source construction and agricultural use, which is reported under mobile sources. Construction and agricultural mobile source fuel use was obtained from EPA (2018) and FHWA (1996 through 2018). Estimates for wood biomass consumption for fuel combustion do not include municipal solid waste, tires, etc., that are reported as biomass by EIA. Non-CO_2 emissions from combustion of the biogenic portion of municipal solid waste and tires is included under waste incineration (Section 3.3). Estimates for natural gas combustion do not include biogas, and therefore non-CO_2 emissions from biogas are not included (see the Planned Improvements section, below). Tier 1 default emission factors for the industrial, commercial, and residential end-use sectors were provided by the *2006 IPCC*

[53] 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.

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 electric power sector by control-technology type was based on EPA's Acid Rain Program Dataset (EPA 2020). Total fuel consumption in the electric power sector from EIA (2019) was apportioned to each combustion technology type and fuel combination using a ratio of fuel consumption by technology type derived from EPA (2020) data. The combustion technology and fuel use data by facility obtained from EPA (2020) were only available from 1996 to 2018, so the consumption estimates from 1990 to 1995 were estimated by applying the 1996 consumption ratio by combustion technology type from EPA (2020) to the total EIA (2019) consumption for each year from 1990 to 1995.

Emissions were estimated by multiplying fossil fuel and wood consumption by technology-, fuel-, and country-specific Tier 2 emission factors. The Tier 2 emission factors used are based in part on emission factors published by EPA, and EPA's Compilation of Air Pollutant Emission Factors, AP-42 (EPA 1997) for coal wall-fired boilers, residual fuel oil, diesel oil and wood boilers, natural gas-fired turbines, and combined cycle natural gas units.[54]

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.[55] For these variables, the uncertainty ranges were assigned to the input variables based on the data reported in SAIC/EIA (2001).[56] However, the CH_4

[54] Several of the U.S. Tier 2 emission factors were used in IPCC (2006) as Tier 1 emission factors. See Table A-92 in Annex 3.1 for emission factors by technology type and fuel type for the electric power sector.

[55] 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.

[56] 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.

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 3-18. Stationary combustion CH_4 emissions in 2018 (including biomass) were estimated to be between 5.6 and 19.9 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 35 percent below to 130 percent above the 2018 emission estimate of 8.7 MMT CO_2 Eq.[57] Stationary combustion N_2O emissions in 2018 (including biomass) were estimated to be between 20.7 and 42.8 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 27 percent below to 51 percent above the 2018 emission estimate of 28.4 MMT CO_2 Eq.

Table 3-18: 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	2018 Emission Estimate (MMT CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (MMT CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Stationary Combustion	CH_4	8.6	5.6	19.9	-35%	+130%
Stationary Combustion	N_2O	28.4	20.7	42.8	-27%	+51%

[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 2018 as discussed below. Details on the emission trends through time are described in more detail in the Methodology section, above. As discussed in Annex 5, data are unavailable to include estimates of CH_4 and N_2O emissions from biomass use in Territories, but those emissions are assumed to be insignificant.

QA/QC and Verification

In order to ensure the quality of the non-CO_2 emission estimates from stationary combustion, general (IPCC Tier 1) and category-specific (Tier 2) Quality Assurance/Quality Control (QA/QC) procedures were implemented consistent with the U.S. Inventory QA/QC plan outlined in Annex 8. 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 greenhouse gas precursors 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 to revised data from EIA (2019) and EPA (2020) relative to the previous Inventory. Most notably, EIA (2019) updated fuel oil consumption statistics in the residential, commercial, and industrial sectors across the time series as a result of updated LPG and fuel ethanol heat contents; revised sectoral allocations for propane and total LPG from 2010 to 2017 and for distillate fuel oil in 2017; and revised 2017 natural gas consumption statistics in all

[57] 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.

sectors. EPA (2020) revised coal, fuel oil, natural gas, and wood consumption statistics for 2017 in the electric power sector. The historical data changes and methodology updates resulted in an average annual decrease of less than 0.01 MMT CO_2 Eq. (0.06 percent) in CH_4 emissions, and an average annual decrease of 0.01 MMT CO_2 Eq. (0.04 percent) in N_2O emissions for the 1990 through 2017 period.

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.

Other forms of biomass-based gas consumption include biogas. EPA will examine EIA and GHGRP data on biogas collected and burned for energy use and determine if CH_4 and N_2O emissions from biogas can be included in future inventories. EIA (2019) 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.

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.[58]

CH_4 and N_2O emissions factors for newer (starting with model year 2004) on-road gasoline vehicles were calculated by Browning (2019) from annual vehicle certification data compiled by EPA. CH_4 and N_2O emissions factors for older (model year 2003 and earlier) on-road gasoline vehicles 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

[58] 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.

emissions and are 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.[59] Diesel on-road vehicle emission factors were developed by ICF (2006a). CH_4 and N_2O emissions factors for newer (starting at model year 2007) on-road diesel vehicles (those using aftertreatment) were calculated from annual vehicle certification data compiled by EPA.

CH_4 and N_2O emission factors for AFVs were developed based on the 2018 GREET model. For light-duty trucks, EPA used a curve fit of 1999 through 2011 travel fractions for LDT1 and LDT2 (MOVES Source Type 31 for LDT1 and MOVES Source Type 32 for LDT2). For medium-duty vehicles, EPA used emission factors for light heavy-duty vocational trucks. For heavy-duty vehicles, EPA used emission factors for long-haul combination trucks. For buses, EPA used emission factors for transit buses. These values represent vehicle operations only (tank-to-wheels); well-to-tank emissions are calculated elsewhere in the Inventory. Biodiesel CH_4 emission factors were corrected from GREET values to be the same as CH_4 emission factors for diesel vehicles. GREET overestimated CH_4 emission factors based upon an incorrect CH_4-to-THC ratio for diesel vehicles with aftertreatment technology.

Annual VMT data for 1990 through 2018 were obtained from the Federal Highway Administration's (FHWA) Highway Performance Monitoring System database as reported in Highway Statistics (FHWA 1996 through 2018).[60] 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 2017) and information on total motor vehicle fuel consumption by fuel type from FHWA (1996 through 2018). VMT for AFVs were estimated based on Browning (2017 and 2018a). The age distributions of the U.S. vehicle fleet were obtained from EPA (2018a, 2000), and the average annual age-specific vehicle mileage accumulation of U.S. vehicles were obtained from EPA (2018a).

Control technology and standards data for on-road vehicles were obtained from EPA's Office of Transportation and Air Quality (EPA 2018a, 2019c, 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) sources.

Non-Road Mobile Sources

To estimate CH_4 and N_2O 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).[61] Activity data were obtained from AAR (2008 through 2018), APTA (2007 through 2018), RailInc (2014 through 2018), APTA (2006), BEA (1991 through 2015), Benson (2002 through 2004), , DLA Energy (2019), DOC (1991 through 2019), DOE (1993 through 2017), DOT (1991 through 2018), EIA (2002, 2007, 2019a), EIA (2019f),

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

[60] 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 2018 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 the current Inventory. These changes are reflected in a large drop in light-truck emissions between 2006 and 2007.

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

EIA (1991 through 2018), EPA (2018a), Esser (2003 through 2004), FAA (2019), FHWA (1996 through 2018),[62] Gaffney (2007), and Whorton (2006 through 2014). Emission factors for non-road modes were taken from IPCC (2006) and Browning (2018b).

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 2018 estimates of CH_4 and N_2O emissions, incorporating probability distribution functions associated with the major input variables. For the purposes of this analysis, the uncertainty was modeled for the following four major sets of input variables: (1) VMT data, by on-road vehicle and fuel type and (2) emission factor data, by on-road vehicle, fuel, and control technology type, (3) fuel consumption, data, by non-road vehicle and equipment type, and (4) emission factor data, by non-road vehicle and equipment type.

Uncertainty analyses were not conducted for NO_x, CO, or NMVOC emissions. Emission factors for these gases have been extensively researched since emissions of these gases from motor vehicles are regulated in the United States, and the uncertainty in these emission estimates is believed to be relatively low. For more information, see Section 3.9. 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 2018 were estimated to be between 2.9 and 4.0 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 8 percent below to 27 percent above the corresponding 2018 emission estimate of 3.1 MMT CO_2 Eq. Also at a 95 percent confidence level, mobile combustion N_2O emissions from mobile sources in 2018 were estimated to be between 14.0 and 17.4 MMT CO_2 Eq., indicating a range of 8 percent below to 14 percent above the corresponding 2018 emission estimate of 15.2 MMT CO_2 Eq.

Table 3-19: Approach 2 Quantitative Uncertainty Estimates for CH_4 and N_2O Emissions from Mobile Sources (MMT CO_2 Eq. and Percent)

Source	Gas	2018 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	3.1	2.9	4.0	-8%	+27%
Mobile Sources	N_2O	15.2	14.0	17.4	-8%	+14%

[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 Annex 7 – Uncertainty. As discussed in Annex 5, data are unavailable to include estimates of CH_4 and N_2O emissions from any liquid fuel used in pipeline

[62] This Inventory uses FHWA's Agriculture, Construction, and Commercial/Industrial MF-24 fuel volumes along with the MOVES 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 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 equipment gasoline volumes in the construction and commercial/industrial categories.

transport or some biomass used in transportation sources, but those emissions are assumed to insignificant.

QA/QC and Verification

In order to ensure the quality of the emission estimates from mobile combustion, general (IPCC Tier 1) and category-specific (Tier 2) Quality Assurance/Quality Control (QA/QC) procedures were implemented consistent with the U.S. Inventory QA/QC plan outlined in Annex 8. The specific plan used for mobile combustion was updated prior to collection and analysis of this current year of data. 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

Updates were made to CH_4 and N_2O emissions factors for on-road gasoline and diesel vehicles. Previously, these factors were based on a regression analysis done by EPA for N_2O and the ratio of NMOG emission standards for CH_4. In this year's Inventory, these emission factors for newer gasoline and diesel vehicles are based on annual certification data compiled by EPA.

In prior Inventories, Class II and Class III rail fuel consumption data was provided by the American Short Line and Regional Railroad Association (ASLRRA). Since ASLRRA no longer tracks and reports fuel consumption data of these rail lines, it is now estimated for years 2014 onwards using carload data reported by Railinc (2014 through 2018).

The collective result of these changes was a net increase in CH_4 emissions and a decrease in N_2O emissions from mobile combustion relative to the previous Inventory. Methane emissions increased by 0.5 percent. Nitrous oxide emissions decreased by 1.1 percent.

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990 through 2018 with one recent notable exception. An update by FHWA 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 2018. Details on the emission trends and methodological inconsistencies through time are described 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.

- Determine new methane and nitrous oxide emission factors for non-road equipment using annual certification data compiled by EPA.
- In previous Inventories, EPA identified the need to evaluate and potentially update EPA's method for estimating motor gasoline consumption for non-road mobile sources, in order 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.[63] These method changes

[63] 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>.

created a time-series inconsistency in the current Inventory between 2015 and previous years in CH_4 and N_2O estimates for agricultural, construction, commercial, and industrial non-road mobile sources. EPA has implemented an approach to address this inconsistency. EPA also tested an alternative approach that uses MOVES on-road fuel consumption output to define the percentage of the FHWA consumption totals (from MF-21) that are attributable to on-highway transportation sources, and applying this percentage to the EIA total, thereby defining gasoline consumption from on-highway transportation sources (such that the remainder would be defined as consumption by the industrial and commercial sectors). Results from this testing revealed differences between fuel consumption calculated by MOVES and fuel consumption data from FHWA. Given this inconsistency, no changes have been made to the methodology for estimating motor gasoline consumption for non-road mobile sources.

- Update emissions factors for ships and boats using residual fuel and distillate fuel, emission factors for locomotives using ultra low sulfur diesel, and emission factors for aircraft using jet fuel. The Inventory is currently using IPCC default values for these emissions factors.
- 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.

3.2 Carbon Emitted from Non-Energy Uses of Fossil Fuels (CRF Source Category 1A5)

In addition to being combusted for energy, fossil fuels are also consumed for non-energy uses 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 products such as lubricants, waxes, and asphalt (IPCC 2006). Emissions from a portion of non-energy uses of fossil fuels are reported in the Energy sector, as opposed to the Industrial Processes and Product Use (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 (see Box 3-5).

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 non-energy use 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 IPPU 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 3-20, fossil fuel emissions in 2018 from the non-energy uses of fossil fuels were 134.6 MMT CO_2 Eq., which constituted approximately 2 percent of overall fossil fuel emissions. In 2018, the consumption of fuels for non-energy uses (after the adjustments described above) was 5,264.7 TBtu (see Table 3-21). A portion of the C in the 5,264.7 TBtu of fuels was stored (221.7 MMT CO_2 Eq.), while the remaining portion was emitted (134.6 MMT CO_2 Eq.). Non-energy use emissions increased 9.3 percent from 2017 to 2018 mainly due to increases in coking coal and petrochemical feedstock use, both of which are driven by changes in economic activity and changes in the industrial sector, see Annex 2.3 for more details.

Table 3-20: CO_2 Emissions from Non-Energy Use Fossil Fuel Consumption (MMT CO_2 Eq. and Percent)

Year	1990	2005	2014	2015	2016	2017	2018
Potential Emissions	312.1	377.5	325.1	340.5	329.9	341.2	356.3
C Stored	192.5	237.8	205.1	213.5	216.2	218.0	221.7
Emissions as a % of Potential	38%	37%	37%	37%	34%	36%	38%
Emissions	**119.5**	**139.7**	**120.0**	**127.0**	**113.7**	**123.1**	**134.6**

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 (2019) (see Annex 2.1). Consumption values for industrial coking coal, petroleum coke, other oils, and natural gas in Table 3-21 and Table 3-22 have been adjusted to subtract non-energy uses that are included in the source categories of the Industrial Processes and Product Use chapter.[64,65] Consumption of natural gas, LPG, pentanes plus, naphthas, other oils, and special naphtha were adjusted to subtract out net exports of these products that are not reflected in the raw data from EIA. 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

[64] 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.

[65] 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 (IPPU) sector. This is not considered to be a significant issue since the non-energy use industrial release data includes different categories of sources than those included in the IPPU sector and the non-energy use estimates are roughly 20 percent of the emissions captured under IPPU. 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.

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 (2006) does not provide guidance on storage factors, and assumptions were made based on the potential fate of C in the respective non-energy use products. Carbon dioxide emissions from carbide production are implicitly accounted for in the storage factor calculation for the non-energy use of petroleum coke.

Table 3-21: Adjusted Consumption of Fossil Fuels for Non-Energy Uses (TBtu)

Year	1990	2005	2014	2015	2016	2017	2018
Industry	**4,215.8**	**5,110.7**	**4,602.9**	**4,764.6**	**4,634.2**	**4,799.5**	**5,049.6**
Industrial Coking Coal	NO	80.4	48.8	121.8	88.6	111.8	124.7
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	323.5	321.9	308.9	307.6	304.7
Asphalt & Road Oil	1,170.2	1,323.2	792.6	831.7	853.4	849.2	792.8
LPG	1,120.5	1,610.0	2,109.8	2,157.5	2,119.0	2,187.7	2,485.5
Lubricants	186.3	160.2	130.7	142.1	135.1	124.9	121.2
Pentanes Plus	117.6	95.5	43.5	78.4	53.1	81.5	104.8
Naphtha (<401 °F)	326.3	679.5	435.2	417.8	396.9	411.1	418.3
Other Oil (>401 °F)	662.1	499.5	236.2	216.8	204.0	241.8	217.7
Still Gas	36.7	67.7	164.5	162.2	166.1	163.8	166.9
Petroleum Coke	27.2	105.2	NO	NO	NO	NO	NO
Special Naphtha	100.9	60.9	104.5	97.0	88.7	94.9	86.5
Distillate Fuel Oil	7.0	11.7	5.8	5.8	5.8	5.8	5.8
Waxes	33.3	31.4	14.8	12.4	12.8	10.2	12.4
Miscellaneous Products	137.8	112.8	182.7	188.9	191.3	198.8	198.0
Transportation	**176.0**	**151.3**	**149.4**	**162.8**	**154.4**	**142.0**	**137.8**
Lubricants	176.0	151.3	149.4	162.8	154.4	142.0	137.8
U.S. Territories	**85.6**	**123.2**	**77.3**	**77.3**	**77.3**	**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	76.2	76.2	76.2	76.2	76.2
Total	**4,477.4**	**5,385.2**	**4,829.6**	**5,004.7**	**4,865.8**	**5,018.8**	**5,264.7**

NO (Not Occurring).

Table 3-22: 2018 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	**5,049.6**	**NA**	**92.8**	**NA**	**60.1**	**32.8**	**120.2**
Industrial Coking Coal	124.7	31.00	3.9	0.10	0.4	3.5	12.8
Industrial Other Coal	10.3	26.08	0.3	0.65	0.2	0.1	0.3
Natural Gas to Chemical Plants	304.7	14.47	4.4	0.65	2.9	1.5	5.6
Asphalt & Road Oil	792.8	20.55	16.3	1.00	16.2	0.1	0.3
LPG	2,485.5	17.06	42.4	0.65	27.7	14.7	53.9
Lubricants	121.2	20.20	2.4	0.09	0.2	2.2	8.2

Pentanes Plus	104.8	19.10	2.0	0.65	1.3	0.7	2.5
Naphtha (<401° F)	418.3	18.55	7.8	0.65	5.1	2.7	9.9
Other Oil (>401° F)	217.7	20.17	4.4	0.65	2.9	1.5	5.6
Still Gas	166.9	17.51	2.9	0.65	1.9	1.0	3.7
Petroleum Coke	+	27.85	+	0.30	+	+	+
Special Naphtha	86.5	19.74	1.7	0.65	1.1	0.6	2.2
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	198.0	20.31	4.0	0.00	+	4.0	14.7
Transportation	**137.8**	**NA**	**2.8**	**NA**	**0.3**	**2.5**	**9.3**
Lubricants	137.8	20.20	2.8	0.09	0.3	2.5	9.3
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	**5,264.7**		**97.2**		**60.5**	**36.7**	**134.6**

Note: Totals may not sum due to independent rounding.
+ 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.

Lastly, emissions were estimated by subtracting the C stored from the potential emissions (see Table 3-20). 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 2019a), *Toxics Release Inventory, 1998* (EPA 2000b), *Biennial Reporting System* (EPA 2000a, 2009), *Resource Conservation and Recovery Act Information System* (EPA 2013b, 2015, 2016b, 2018b), pesticide sales and use estimates (EPA 1998, 1999, 2002, 2004, 2011, 2017), and the Chemical Data Access Tool (EPA 2014b); the EIA Manufacturer's Energy Consumption Survey (MECS) (EIA 1994, 1997, 2001, 2005, 2010, 2013, 2017); the National Petrochemical & Refiners Association (NPRA 2002); the U.S. Census Bureau (1999, 2004, 2009, 2014); Bank of Canada (2012, 2013, 2014, 2016, 2017, 2018, 2019); Financial Planning Association (2006); INEGI (2006); the United States International Trade Commission (1990 through 2018); Gosselin, Smith, and Hodge (1984); EPA's *Municipal Solid Waste (MSW) Facts and Figures* (EPA 2013, 2014a, 2016a, 2018a, 2019b); the Rubber Manufacturers' Association (RMA 2009, 2011, 2014, 2016, 2018); 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 Independent Chemical Information Service (ICIS 2008, 2016); the EPA Chemical Data Access Tool (CDAT) (EPA 2014b); the American Chemistry Council (ACC 2003 through 2011, 2013, 2014, 2015, 2016, 2017, 2018, 2019b); and the *Guide to the Business of Chemistry* (ACC 2019a). 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 3-21 and Table 3-22), 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 3-23 (emissions) and Table 3-24 (storage factors). Carbon emitted from non-energy uses of fossil fuels in 2018 was estimated to be between 96.8 and 188.8 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 28 percent below to 40 percent above the 2018 emission estimate of 134.6 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 3-23: Approach 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Non-Energy Uses of Fossil Fuels (MMT CO_2 Eq. and Percent)

Source	Gas	2018 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	83.7	53.9	142.3	-36%	+70%
Asphalt	CO_2	0.3	0.1	0.6	-58%	+118%
Lubricants	CO_2	17.5	14.4	20.3	-18%	+16%
Waxes	CO_2	0.4	0.3	0.7	-24%	+80%
Other	CO_2	32.7	18.8	35.6	-43%	+9%
Total	**CO_2**	**134.6**	**96.8**	**188.8**	**-28%**	**40%**

Note: Totals may not sum due to independent rounding.
[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Table 3-24: Approach 2 Quantitative Uncertainty Estimates for Storage Factors of Non-Energy Uses of Fossil Fuels (Percent)

Source	Gas	2018 Storage Factor (%)	Uncertainty Range Relative to Emission Estimate[a] (%)		(%, Relative)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Feedstocks	CO_2	65.3%	51.9%	71.9%	-21%	+10%
Asphalt	CO_2	99.6%	99.1%	99.8%	-0.5%	+0.2%
Lubricants	CO_2	9.2%	3.9%	17.5%	-57%	+90%
Waxes	CO_2	57.8%	47.6%	67.6%	-18%	+17%
Other	CO_2	6.3%	6.0%	42.8%	-4%	+582%

[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).

As shown in Table 3-24, 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 2018 as discussed below. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

In order to ensure the quality of the emission estimates from non-energy uses of fossil fuels, general (IPCC Tier 1) and category-specific (Tier 2) Quality Assurance/Quality Control (QA/QC) procedures were implemented consistent with the U.S. Inventory QA/QC plan outlined in Annex 8. This effort included a general analysis, as well as portions of a category specific 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 with 2017 totals 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 exceeded outputs, then starting in 2001 through 2009, outputs exceeded inputs. Inputs exceeded outputs in 2010, 2011, and 2013 through 2018, but outputs exceeded inputs in 2012. A portion of this discrepancy has been reduced and two strategies have been developed to address the remaining portion (see the Planned Improvements section, below).

Recalculations Discussion

Previously proxied data for five chemicals and fibers (polyester fiber, polyolefin fiber, nylon fiber, acetic acid, and maleic anhydride) were updated using the *Guide to the Business of Chemistry, 2019* for 1990 through 2017 values. Overall, these changes resulted in an average annual decrease of less than 0.01 MMT CO_2 Eq. (less than 0.01 percent) in carbon emissions from non-energy uses of fossil fuels for the period 1990 through 2017, relative to the previous Inventory.

Planned Improvements

There are several future improvements planned:

- Analyzing the fuel and feedstock data from EPA's GHGRP Subpart X (Petrochemical Production) 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.

- 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 3-5: 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 IPPU sector.[66] 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 (CRF Source Category 1A5).[67]

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 3-22).

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.[68] 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 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.

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

[67] 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*.

[68] Data and calculations for lubricants and waxes and asphalt and road oil are in Annex 2.3 – Methodology for Estimating Carbon Emitted from Non-Energy Uses of Fossil Fuels.

3.3 Incineration of Waste (CRF Source Category 1A5)

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; EPA 2018a; 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 the *2006 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 MSW 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 MSW 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 MSW. 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 20.8 million metric tons of MSW were incinerated in 2011 (van Haaren et al. 2010). Updated data were not available for 2012 through 2018 from this source so the data were proxied to the 2011 estimate. Carbon dioxide emissions from incineration of waste increased 40 percent since 1990, to an estimated 11.1 MMT CO_2 (11,113 kt) in 2018, as the volume of scrap tires and other fossil C-containing materials in waste increased (see Table 3-25 and Table 3-26).

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 2018 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 2018 and have decreased by 32 percent since 1990.

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

Gas/Waste Product	1990	2005	2014	2015	2016	2017	2018
CO_2	**8.0**	**12.5**	**10.4**	**10.8**	**10.9**	**11.1**	**11.1**
Plastics	5.6	6.9	5.9	6.2	6.2	6.4	6.4
Synthetic Rubber in Tires	0.3	1.6	1.2	1.1	1.2	1.2	1.2
Carbon Black in Tires	0.4	2.0	1.4	1.4	1.4	1.4	1.4
Synthetic Rubber in MSW	0.9	0.8	0.7	0.7	0.7	0.7	0.7
Synthetic Fibers	0.8	1.2	1.3	1.3	1.4	1.4	1.4
CH_4	+	+	+	+	+	+	+
N_2O	**0.5**	**0.4**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**
Total	**8.4**	**12.9**	**10.7**	**11.1**	**11.2**	**11.4**	**11.4**

+ Does not exceed 0.05 MMT CO_2 Eq.

Table 3-26: CO_2, CH_4, and N_2O Emissions from the Incineration of Waste (kt)

Gas/Waste Product	1990	2005	2014	2015	2016	2017	2018
CO_2	**7,951**	**12,469**	**10,435**	**10,756**	**10,919**	**11,111**	**11,113**
Plastics	5,588	6,919	5,928	6,184	6,227	6,388	6,388
Synthetic Rubber in Tires	308	1,599	1,154	1,149	1,160	1,171	1,171
Carbon Black in Tires	385	1,958	1,406	1,401	1,415	1,430	1,430
Synthetic Rubber in MSW	854	766	692	703	717	731	731
Synthetic Fibers	816	1,227	1,255	1,319	1,399	1,392	1,394
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 MSW 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 MSW (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; EPA 2016; EPA 2018a; EPA 2019) and detailed unpublished backup data for some years not shown in the reports (Schneider 2007). For 2012 through 2018 data on total waste incinerated were assumed to equal to the 2011 value from Shin (2014) for 2012 through 2018. For synthetic rubber and carbon black in scrap tires, information was obtained biannually from U.S. Scrap Tire Management Summary for 2005 through 2018 data (RMA 2018). Average C contents for the "Other" plastics category and synthetic rubber in MSW 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 2018, so these values were assumed to equal the 2011 *BioCycle* dataset value.

Table 3-27 provides data on MSW discarded and percentage combusted for the total waste stream. The emission factors of N_2O and CH_4 emissions per quantity of MSW combusted are default emission factors for the default continuously-fed stoker unit MSW incineration technology type and were taken from IPCC (2006).

Table 3-27: 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%
2014	273,116,704[a]	20,756,870	7.6%
2015	273,116,704[a]	20,756,870	7.6%
2016	273,116,704[a]	20,756,870	7.6%
2017	273,116,704[a]	20,756,870	7.6%
2018	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 3-28. Waste incineration CO_2 emissions in 2018 were estimated to be between 8.2 and 14.4 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 26 percent below to 29 percent above the 2018 emission estimate of 11.1 MMT CO_2 Eq. Also at a 95 percent confidence level, waste incineration N_2O emissions in 2018 were estimated to be between 0.2

and 1.3 MMT CO_2 Eq. This indicates a range of 51 percent below to 328 percent above the 2018 emission estimate of 0.3 MMT CO_2 Eq. Differences observed in comparison to last year were due to a reevaluation and refinement of assumptions on scrap tire weights of light and heavy-duty tires.

Table 3-28: Approach 2 Quantitative Uncertainty Estimates for CO_2 and N_2O from the Incineration of Waste (MMT CO_2 Eq. and Percent)

Source	Gas	2018 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	11.1	8.2	14.4	-26%	29%
Incineration of Waste	N_2O	0.3	0.2	1.3	-51%	328%

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

QA/QC and Verification

In order to ensure the quality of the emission estimates from waste incineration, general (IPCC Tier 1) and category-specific (Tier 2) Quality Assurance/Quality Control (QA/QC) procedures were implemented consistent with the U.S. Inventory QA/QC plan outlined in Annex 8. 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. Corrective actions were taken to rectify minor errors in the use of activity data.

Recalculations Discussion

EPA revised the percent of tires disposed for light duty tires and commercial tires in 2009 and 2013 to reflect updated data. For 2009, EPA used data from the Rubber Manufacturers Association's (RMA) *U.S. Scrap Tire Management Summary 2005-2009 (RMA 2013),* and RMA's *2013 U.S. Scrap Tire Management Summary (RMA 2014)* for 2013. These updates impacted CO_2 emissions from synthetic rubber in tires and synthetic rubber in MSW.

EPA also updated the total generation and recovery data for plastics, synthetic rubber, and synthetic fibers in MSW for years 2016 and 2017. In the previous Inventory report, emissions were being proxied from 2015 values. EPA used data from EPA's *Advancing Sustainable Materials Management: Facts and Figures 2016 and 2017, Assessing Trends in Material Generation, Recycling and Disposal in the United States* (EPA 2019). The updates to MSW discarded impacted CO_2 emissions for those materials in 2016 and 2017.

Planned Improvements

The waste incineration estimates have recently relied on MSW mass flow (i.e., tonnage) data that has not been updated since 2011. These values previously came from *BioCycle* (Shin 2014) and *EPA Facts and Figures* (EPA 2015). EPA performed an examination of facility-level MSW tonnage data availability, primarily focusing on EPA's GHGRP data, Energy Information Administration (EIA) waste-to-energy data, and other sources. EPA concluded that the GHGRP data were more complete (i.e., included more facilities), but did not contain data for all inventory years (1990 through 2016). The EIA data can be used to supplement years not available in the GHGRP dataset. In addition, the GHGRP data do not include specific waste components outside of an assumed biogenic and fossil component, which is necessary for CO_2 emission calculations. Data from EPA's GHGRP on fossil CO_2 emissions can be used to benchmark results for other waste components in the Inventory.

Additional improvements will focus on investigating new methods and sources for CO_2 emission estimates and investigating new data sources for MSW incinerated values (i.e., tonnage) for estimating CO_2 and non-CO_2 (CH_4, N_2O) emissions.

Proposed improvements to the current CO_2 emissions estimation methodology include opportunities for either incorporating total CO_2 emissions from existing waste incineration datasets (i.e., EIA and GHGRP data that provide CO_2 emission estimates) or updating emission factors (i.e., MSW carbon content) and continuing to use the *Facts and Figures* disposal data for fossil-based products. Further research is required to compare the emission factors (i.e., MSW carbon content, heating values) used across waste incineration CO_2 emissions approaches, including the current Inventory, EIA, and EPA's GHGRP. In addition, the currently used *BioCycle* percent combusted assumption could be updated with *Facts and Figures* product tonnage combusted data.

Non-CO_2 improvements will focus on research of potential data sources for updating emission factors. EPA is also researching potential data sources for incinerated MSW tonnage that can be used for future inventory years instead of applying an incineration rate to generated MSW tonnage. EPA is analyzing the *Facts and Figures* non-tire MSW combusted tonnage and previously compiled EIA and GHGRP tonnage data to compare organic and non-organic components of these MSW tonnage data where available.

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 C content of fibers within scrap tires will 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 (CRF 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 3-30 and Table 3-31) due to the higher CH_4 content of coal in the deeper underground coal seams. In 2018, 236 underground coal mines and 430 surface mines were operating in the United States (EIA 2019). In recent years the total number of active coal mines in the United States has declined. In 2018, the United States was the third-largest coal producer in the world (686 MMT), after China (3,550 MMT) and India (771 MMT) (IEA 2019).

Table 3-29: 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
2014	345	321,783	613	583,974	958	905,757
2015	305	278,342	529	534,092	834	812,435
2016	251	228,707	439	431,285	690	659,991
2017	237	247,779	434	454,303	671	702,082
2018	236	249,802	430	435,521	666	685,324

Underground mines liberate CH_4 from ventilation systems and from degasification systems. Ventilation systems pump air through the mine workings to dilute noxious gases and ensure worker safety; these systems can exhaust significant amounts of CH_4 to the atmosphere in low concentrations. Degasification systems are wells drilled from

the surface or boreholes drilled inside the mine that remove large, often highly concentrated volumes of CH_4 before, during, or after mining. Some mines recover and use CH_4 generated from ventilation and degasification systems, thereby reducing emissions to the atmosphere.

Surface coal mines liberate CH_4 as the overburden is removed and the coal is exposed to the atmosphere. Methane emissions are normally a function of coal rank (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 2018 were estimated to be 2,109.3 kt (52.7 MMT CO_2 Eq.), a decline of approximately 45 percent since 1990 (see Table 3-30 and Table 3-31). In 2018, underground mines accounted for approximately 74 percent of total emissions, surface mines accounted for 13 percent, and post-mining activities accounted for 13 percent. In 2018, total CH_4 emissions from coal mining decreased by approximately 4 percent relative to the previous year. This decrease was due to a modest decrease in coal production and an increase in CH_4 recovered and used. The amount of CH_4 recovered and used in 2018 increased by approximately eleven percent compared to 2017 levels. This increase is primarily attributed to an increase in reported CH_4 recovery and use at three mines.

Table 3-30: CH_4 Emissions from Coal Mining (MMT CO_2 Eq.)

Activity	1990	2005	2014	2015	2016	2017	2018
Underground (UG) Mining	**74.2**	**42.0**	**46.1**	**44.9**	**40.7**	**40.7**	**38.9**
Liberated	80.8	59.7	63.0	61.2	57.0	57.6	57.7
Recovered & Used	(6.6)	(17.7)	(17.0)	(16.4)	(16.4)	(17.0)	(18.8)
Surface Mining	**10.8**	**11.9**	**9.6**	**8.7**	**6.8**	**7.2**	**7.0**
Post-Mining (UG)	**9.2**	**7.6**	**6.7**	**5.8**	**4.8**	**5.3**	**5.3**
Post-Mining (Surface)	**2.3**	**2.6**	**2.1**	**1.9**	**1.5**	**1.6**	**1.5**
Total	**96.5**	**64.1**	**64.6**	**61.2**	**53.8**	**54.8**	**52.7**

Table 3-31: CH_4 Emissions from Coal Mining (kt)

Activity	1990	2005	2014	2015	2016	2017	2018
Underground (UG) Mining	**2,968**	**1,682**	**1,844**	**1,796**	**1,629**	**1,626**	**1,556**
Liberated	3,234	2,390	2,523	2,450	2,283	2,306	2,308
Recovered & Used	(266)	(708)	(679)	(654)	(654)	(679)	(752)
Surface Mining	**430**	**475**	**386**	**347**	**273**	**290**	**280**
Post-Mining (UG)	**368**	**306**	**270**	**231**	**193**	**213**	**212**
Post-Mining (Surface)	**93**	**103**	**84**	**75**	**59**	**63**	**61**
Total	**3,860**	**2,565**	**2,583**	**2,449**	**2,154**	**2,191**	**2,109**

Methodology

EPA uses an IPCC Tier 3 method for estimating CH_4 emissions from underground coal mining and an IPCC Tier 2 method for estimating CH_4 emissions from surface mining and post-mining activities (for both coal production from underground mines and surface mines). 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 degasification systems. Some mines recover and use the liberated 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)[69] (Subpart FF, "Underground Coal Mines"), data provided by the U.S. Mine Safety and Health Administration (MSHA) (MSHA 2019), 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 17,525 MT CO_2 Eq.)—have been required to report to EPA's GHGRP (EPA 2019).[70] Mines that report to EPA's GHGRP must report quarterly measurements of CH_4 emissions from ventilation systems; they have the option of recording and reporting 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.[71]

Since 2013, ventilation CH_4 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 CH_4 emission rate for the reporting year quarter. Because not all mines report under EPA's 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. Eighteen mines used degasification systems in 2018, and the CH_4 removed through these systems was reported to EPA's GHGRP under Subpart FF (EPA 2019). Based on the weekly measurements reported to EPA's GHGRP, degasification data summaries for each mine were added to estimate the CH_4 liberated from degasification systems. Eleven of the 18 mines with degasification systems had operational CH_4 recovery and use projects (see step 1.3 below), and EPA's GHGRP reports show the remaining seven mines vented CH_4 from degasification systems to the atmosphere.[72]

Degasification data reported to EPA's GHGRP by underground coal mines is the primary source of data used to develop estimates of CH_4 liberated from degasification systems. Data reported to EPA's GHGRP were used

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

[70] Underground coal mines report to EPA under Subpart FF of the GHGRP (40 CFR Part 98). In 2018, 76 underground coal mines reported to the program.

[71] 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.

[72] Several of the mines venting CH_4 from degasification systems use a small portion of 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.

exclusively to estimate CH_4 liberated from degasification systems at 14 of the 18 mines that used degasification systems in 2018.

For pre-mining wells, cumulative degasification volumes that occur prior to the well being mined through are attributed to the mine in the inventory year in which the well is mined through.[73] EPA's GHGRP does not require gas production from virgin coal seams (coalbed methane) to be reported by coal mines under Subpart FF.[74] Most pre-mining wells drilled from the surface are considered coalbed methane wells prior to mine-through and associated CH_4 emissions are reported under another subpart of the GHGRP (Subpart W, "Petroleum and Natural Gas Systems"). As a result, GHGRP data must be supplemented to estimate cumulative degasification volumes that occurred prior to well mine-through. There were four mines with degasification systems that include pre-mining wells that were mined through in 2018. For these mines, GHGRP data were supplemented with historical data from state gas well production databases (GSA 2019; DMME 2019; WVGES 2019), as well as with mine-specific information regarding the locations and dates on which the pre-mining wells were mined through (JWR 2010; El Paso 2009; ERG 2019).

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

Thirteen mines had CH_4 recovery and use projects in place in 2018. Eleven of these projects involved degasification systems, one did not use any degasification system, and one involved a ventilation air methane abatement project (VAM). Eleven of these mines sold the recovered CH_4 to a pipeline, including one that also used CH_4 to fuel a thermal coal dryer. One mine used recovered CH_4 to heat mine ventilation air (data was unavailable for estimating CH_4 recovery at this mine). One mine destroyed the recovered CH_4 (VAM) using Regenerative Thermal Oxidation (RTO) without energy recovery.

The CH_4 recovered and used (or destroyed) at the twelve mines described above for which data were available were estimated using the following methods:

- EPA's GHGRP data was exclusively used to estimate the CH_4 recovered and used from seven of the 11 mines that deployed degasification systems in 2018. 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.
- State sales data were used to estimate CH_4 recovered and used from the remaining four mines that deployed degasification systems in 2018 (DMME 2019, GSA 2019). These four mines intersected pre-mining wells in 2018. Supplemental information was used for these 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 prior to the well being mined through. The supplemental data came from state gas production databases as well as mine-specific information on the timing of mined-through pre-mining wells.
- For the single mine that employed VAM for CH_4 recovery and use, the estimates of CH_4 recovered and used were obtained from the mine's offset verification statement (OVS) submitted to the California Air Resources Board (CARB) (McElroy OVS 2019).

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

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

[74] This applies for pre-drainage in years prior to the well being mined through. Beginning with the year the well is mined through, the annual volume of CH_4 liberated from a pre-drainage well is reported under Subpart FF of EPA's GHGRP.

Annual Coal Report (EIA 2019) 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 emission 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). Equipment measurement uncertainty is applied to both GHGRP and MSHA data.

Estimates of CH_4 liberated and recovered by degasification systems are relatively certain for utilized CH_4 because of the availability of EPA's GHGRP data and gas sales information. Many of the liberation and 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 liberated CH_4 and 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 CH_4 utilized 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 sub-source. 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.

Beginning in 2015, a small level of uncertainty was introduced by using estimated rather than measured values of recovered CH_4 from two of the mines with degasification systems. An increased level of uncertainty was applied to these two sub-sources, 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 3-32. Coal mining CH_4 emissions in 2018 were estimated to be between 43.9 and 59.2 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 16.7 percent below to 12.3 percent above the 2018 emission estimate of 52.7 MMT CO_2 Eq.

Table 3-32: Approach 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Coal Mining (MMT CO_2 Eq. and Percent)

Source	Gas	2018 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	52.7	43.9	59.2	-16.7%	+12.3%

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

QA/QC and Verification

In order to ensure the quality of the emission estimates for coal mining, general (IPCC Tier 1) and category-specific (Tier 2) Quality Assurance/Quality Control (QA/QC) procedures were implemented consistent with the U.S. Inventory QA/QC plan outlined in Annex 8. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and reported emissions data used for estimating emissions from coal mining. Trends across the time series were analyzed to determine whether any corrective actions were needed.

Emission estimates for coal mining rely in large part on data reported by coal mines to EPA's GHGRP. EPA verifies annual facility-level reports through a multi-step process to identify potential errors and ensure that data submitted to EPA are accurate, complete, and consistent. All reports submitted to EPA are evaluated by electronic validation and verification checks. If potential errors are identified, EPA will notify the reporter, who can resolve the issue either by providing an acceptable response describing why the flagged issue is not an error or by correcting the flagged issue and resubmitting their annual greenhouse gas report. Additional QA/QC and verification procedures occur for each GHGRP subpart.

Recalculations Discussion

No recalculations were performed for the 1990 through 2017 portion of the time series.

Planned Improvements

EPA intends to add methods for estimating fugitive CO_2 emissions from underground and surface mining, based on methods included in the *2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories*.

3.5 Abandoned Underground Coal Mines (CRF 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 2018, 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[75] 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. In 2018 there was one gassy mine closure. Gross abandoned mine emissions decreased slightly from 9.2 MMT CO_2 Eq. in 2017 to 8.9 MMT CO_2 Eq. in 2018 (see Table 3-33 and Table 3-34). Gross emissions are reduced by CH_4 recovered and used at 45 mines, resulting in net emissions in 2018 of 6.2 MMT CO_2 Eq.

Table 3-33: CH_4 Emissions from Abandoned Coal Mines (MMT CO_2 Eq.)

Activity	1990	2005	2014	2015	2016	2017	2018
Abandoned Underground Mines	7.2	8.4	8.7	9.0	9.5	9.2	8.9
Recovered & Used	+	(1.8)	(2.4)	(2.6)	(2.8)	(2.7)	(2.7)
Total	**7.2**	**6.6**	**6.3**	**6.4**	**6.7**	**6.4**	**6.2**

Note: Parentheses indicate negative values.
+ Does not exceed 0.05 MMT CO_2 Eq.

Table 3-34: CH_4 Emissions from Abandoned Coal Mines (kt)

Activity	1990	2005	2014	2015	2016	2017	2018
Abandoned Underground Mines	288	334	350	359	380	367	355
Recovered & Used	+	(70)	(97)	(102)	(112)	(109)	(107)
Total	**288**	**264**	**253**	**256**	**268**	**257**	**247**

+ Does not exceed 0.5 kt.

Methodology

Estimating CH_4 emissions from an abandoned coal mine requires predicting the emissions of a mine from the time of abandonment through the inventory year of interest. The flow of CH_4 from the coal to the mine void is primarily dependent on the mine's emissions when active and the extent to which the mine is flooded or sealed. The CH_4 emission rate before abandonment reflects the gas content of the coal, 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

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

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. For this analysis of flooded abandoned mines, there was not enough data to establish basin-specific equations, as was done with the vented, non-flooding mines (EPA 2004). This decline through time can be empirically expressed as:

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

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) of CH_4 account for about 98 percent of all CH_4 emissions. This same relationship is assumed for abandoned mines. It was determined that the 533 abandoned mines closed after 1972 produced CH_4 emissions greater than 100 mcfd when active. Further, the status of 305 of the 533 mines (or 57 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 43 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 3-35: Number of Gassy Abandoned Mines Present in U.S. Basins in 2018, Grouped by Class According to Post-Abandonment State

Basin	Sealed	Vented	Flooded	Total Known	Unknown	Total Mines
Central Appl.	41	26	52	119	148	267
Illinois	34	3	14	51	31	82
Northern Appl.	47	22	16	85	39	124
Warrior Basin	0	0	16	16	0	16
Western Basins	28	4	2	34	10	44
Total	**150**	**55**	**100**	**305**	**228**	**533**

Inputs to the decline equation require the average CH_4 emission rate prior to abandonment and the date of abandonment. Generally, these data are 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. 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 2019). Coal mine degasification data are not available for years prior to 1990, thus the initial emission rates used reflect only ventilation emissions 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 2018. Since the sample of gassy mines described above 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 2018, emission totals were downwardly adjusted to reflect CH_4 emissions avoided from those abandoned mines with CH_4 recovery and use or destruction systems. The Inventory totals were not adjusted for abandoned mine CH_4 emission reductions from 1990 through 1992, because no data was reported for abandoned coal mine CH_4 recovery and use or destruction 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 3-36. Annual abandoned coal mine CH_4 emissions in 2018 were estimated to be between 5.0 and 7.1 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 20 percent below to 15 percent above the 2018 emission estimate of 6.2 MMT CO_2 Eq. One of the reasons for the relatively narrow range is that mine-specific data is available for use in the methodology for mines closed after 1972. Emissions from mines closed prior to 1972 have the largest degree of uncertainty because no mine-specific CH_4 liberation rates exist.

Table 3-36: Approach 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Abandoned Underground Coal Mines (MMT CO_2 Eq. and Percent)

Source	Gas	2018 Emission Estimate (MMT CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (MMT CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Abandoned Underground Coal Mines	CH_4	6.2	5.0	7.1	-20%	+15%

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

QA/QC and Verification

In order to ensure the quality of the emission estimates for abandoned coal mines, general (IPCC Tier 1) and category-specific (Tier 2) Quality Assurance/Quality Control (QA/QC) procedures were implemented consistent with the U.S. Inventory QA/QC plan outlined in Annex 8. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and reported emissions data used for estimating emissions from abandoned coal mines. Trends across the time series were analyzed to determine whether any corrective actions were needed.

Recalculations Discussion

No recalculations were performed for the 1990 through 2017 portion of the time series.

3.6 Petroleum Systems (CRF Source Category 1B2a)

This IPCC category (1B2a) is for fugitive emissions, which per IPCC include emissions from leaks, venting, and flaring. 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 emissions from leaks, venting (including emissions from operational upsets), and flaring. Carbon dioxide emissions from petroleum systems are primarily associated with crude oil production and refining operations. Note, CO_2 emissions exclude all combustion emissions (e.g., engine combustion) except for flaring CO_2 emissions. All

combustion CO_2 emissions (except for flaring) are accounted for in the fossil fuel combustion chapter (see Section 3.1). Emissions of N_2O from petroleum systems are primarily associated with flaring. Total greenhouse gas emissions (CH_4, CO_2, and N_2O) from petroleum systems in 2018 were 73.1 MMT CO_2 Eq., an increase of 31 percent from 1990, primarily due to increases in CO_2 emissions. Since 2008, total emissions increased by 30 percent; and since 2017, total emissions increased by 16 percent. Total CO_2 emissions from petroleum systems in 2018 were 36.8 MMT CO_2 (36,814 kt CO_2), an increase of a factor of 2.8 from 1990. Since 2008, total CO_2 emissions increased by a factor of 1.7, and since 2017 CO_2 emissions increased by 50 percent. Total CH_4 emissions from petroleum systems in 2018 were 36.2 MMT CO_2 Eq. (1,449 kt CH_4), a decrease of 21 percent from 1990. Since 2008, total CH_4 emissions decreased by 15 percent; and since 2017, CH_4 emissions decreased by 6 percent. Total N_2O emissions from petroleum systems in 2018 were 0.07 MMT CO_2 Eq. (0.24 kt N_2O), an increase of a factor of 3.2 from 1990. Since 2008, total N_2O emissions increased by a factor of 2.7; and since 2017, N_2O emissions increased by a factor of 1.6. Since 1990, U.S. oil production has increased by 49 percent; from 2008 to 2018, production increased by a factor of 1.2; and from 2017 to 2018, production increased by 18 percent.

Each year, some estimates in the Inventory are recalculated with improved methods and/or data. These improvements are implemented consistently across the previous Inventory's time series (i.e., 1990 to 2017) to ensure that the trend is accurate. Recalculations in petroleum systems in this year's Inventory include:

- Revised offshore oil production methodology
- Revised emissions for delayed cokers in refineries, due to a methodological change in GHGRP reporting for Subpart Y
- Recalculations due to GHGRP submission revisions

The Recalculations Discussion section below provides more details on the updated methods.

Exploration. Exploration includes well drilling, testing, and completions. Exploration accounts for approximately 1 percent of total CH_4 emissions (including leaks, vents, and flaring) from petroleum systems in 2018. The predominant sources of emissions from exploration are hydraulically fractured oil well completions and well drilling. Other sources include well testing and well completions without hydraulic fracturing. Since 1990, exploration CH_4 emissions have decreased 88 percent, and while the number of hydraulically fractured wells completed increased by a factor of 2.6, there were decreases in the fraction of such completions without reduced emissions completions (RECs) or flaring (from 90 percent in 1990 to 1 percent in 2018). Emissions of CH_4 from exploration were highest in 2012, over 20 times higher than in 2018; and lowest in 2017. Emissions of CH_4 from exploration increased 11 percent from 2017 to 2018, due to an increase in hydraulically fractured oil well completions with flaring. Exploration accounts for 8 percent of total CO_2 emissions (including leaks, vents, and flaring) from petroleum systems in 2018. Emissions of CO_2 from exploration in 2018 increased by a factor of 7.4 from 1990 levels, and 76 percent from 2017, due to the abovementioned increase in hydraulically fractured oil well completions with flaring. Emissions of CO_2 from exploration were highest in 2014, around 11 percent higher than in 2018. Exploration accounts for 2 percent of total N_2O emissions from petroleum systems in 2018. Emissions of N_2O from exploration in 2018 increased by a factor of 8.4 from 1990, and by a factor of 1.4 from 2017, due to the abovementioned increase in hydraulically fractured oil well completions with flaring.

Production. Production accounts for approximately 96 percent of total CH_4 emissions (including leaks, vents, and flaring) from petroleum systems in 2018. The predominant sources of emissions from production field operations are pneumatic controllers, offshore oil platforms, gas engines, chemical injection pumps, leaks from oil wellheads, and oil tanks. These six sources together account for 91 percent of the CH_4 emissions from production. Since 1990, CH_4 emissions from production have decreased by 17 percent due to decreases in emissions from offshore platforms, tanks, and pneumatic controllers. Overall, production segment methane emissions decreased by 7 percent from 2017 levels due primarily to a decrease in the number of intermittent bleed controllers as use of low bleed controllers grew in 2018. Production emissions account for 82 percent of the total CO_2 emissions (including leaks, vents, and flaring) from petroleum systems in 2018. The principal sources of CO_2 emissions are associated gas flaring, oil tanks with flares, and miscellaneous production flaring. These three sources together account for 98 percent of the CO_2 emissions from production. Since 1990, CO_2 emissions from production have increased by a factor of 4.0, due to increases in flaring emissions from associated gas flaring, tanks, and miscellaneous production

flaring. Overall, production segment CO_2 emissions increased by 58 percent from 2017 levels primarily due to an increase in associated gas flaring in the Permian and Williston basins. Production emissions account for 83 percent of the total N_2O emissions from petroleum systems in 2018. The principal sources of N_2O emissions are oil tanks with flares, miscellaneous production flaring, and associated gas flaring. Since 1990, N_2O emissions from production have increased by a factor of 6.9; and since 2017, N_2O emissions from production have increased by a factor of 2.8, due primarily to increases in N_2O from oil tanks with flares and miscellaneous production flaring.

Crude Oil Transportation. Emissions from crude oil transportation account for a very small percentage of the total emissions (including leaks, vents, and flaring) from petroleum systems and have little impact on the overall emissions. Crude oil transportation activities account for less than 1 percent of total CH_4 emissions from petroleum systems. Emissions from tanks, marine loading, and truck loading operations account for 75 percent of CH_4 emissions from crude oil transportation. Since 1990, CH_4 emissions from transportation have increased by 29 percent. In 2018, CH_4 emissions from transportation increased by 10 percent from 2017 levels. Crude oil transportation activities account for less than 0.01 percent of total CO_2 emissions from petroleum systems. Emissions from tanks, marine loading, and truck loading operations account for 75 percent of CO_2 emissions from crude oil transportation.

Crude Oil Refining. Crude oil refining processes and systems account for 2 percent of total fugitive (including leaks, vents, and flaring) CH_4 emissions from petroleum systems. This low share is because most of the CH_4 in crude oil is removed or escapes before the crude oil is delivered to the refineries. There is an insignificant amount of CH_4 in all refined products. Within refineries, flaring accounts for 38 percent of the CH_4 emissions, while delayed cokers, uncontrolled blowdowns, and process vents account for 18, 17, and 9 percent, respectively. Fugitive CH_4 emissions from refining of crude oil have increased by 14 percent since 1990, and decreased 7 percent from 2017; however, like the transportation subcategory, this increase has had little effect on the overall emissions of CH_4 from petroleum systems. Crude oil refining processes and systems account for 10 percent of total fugitive (including leaks, vents, and flaring) CO_2 emissions from petroleum systems. Of the total fugitive CO_2 emissions, almost all (about 98 percent) of it comes from flaring.[76] Refinery fugitive CO_2 emissions increased by 14 percent from 1990 to 2018 and increased by less than 1 percent from the 2017 levels. Flaring occurring at crude oil refining processes and systems accounts for 15 percent of total fugitive N_2O emissions from petroleum systems. Refinery fugitive N_2O emissions increased by 16 percent from 1990 to 2018 and decreased by 2 percent from 2017 levels.

Table 3-37: CH_4 Emissions from Petroleum Systems (MMT CO_2 Eq.)

Activity	1990	2005	2014	2015	2016	2017	2018
Exploration[a]	**3.0**	**4.5**	**5.1**	**2.1**	**0.5**	**0.3**	**0.4**
Production (Total)	**42.4**	**33.4**	**37.5**	**37.4**	**37.5**	**37.3**	**34.9**
Pneumatic Controllers	19.3	17.6	19.6	19.7	20.6	21.3	18.4
Offshore Production	9.3	6.5	5.7	5.5	5.1	5.1	5.1
Equipment Leaks[b]	2.2	2.2	2.7	2.7	2.6	2.6	2.5
Gas Engines	2.1	1.7	2.3	2.3	2.2	2.2	2.3
Chemical Injection Pumps	1.2	1.7	2.2	2.2	2.1	2.1	2.0
Tanks	5.4	1.5	1.6	1.7	2.5	1.5	1.4
Other Sources	2.6	2.1	3.3	3.3	2.3	2.6	3.2
Crude Oil Transportation	**0.2**	**0.1**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**
Refining	**0.7**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**
Total	**46.1**	**38.8**	**43.5**	**40.5**	**39.0**	**38.7**	**36.2**

Note: Totals may not sum due to independent rounding.

[a] Exploration includes well drilling, testing, and completions.

[b] Includes leak emissions from wellheads, separators, heaters/treaters, and headers.

[76] Petroleum Systems includes fugitive emissions f(leaks, venting, and flaring). In many industries, including petroleum refineries, the largest source of onsite CO_2 emissions is often fossil fuel combustion, which is covered in section 3.1 of this chapter.

Table 3-38: CH_4 Emissions from Petroleum Systems (kt CH_4)

Activity	1990	2005	2014	2015	2016	2017	2018
Exploration[a]	**121**	**181**	**202**	**84**	**19**	**13**	**15**
Production (Total)	**1,689**	**1,336**	**1,498**	**1,496**	**1,499**	**1,494**	**1,395**
Pneumatic Controllers	772	704	783	789	823	851	735
Offshore Production	372	261	230	220	205	205	202
Equipment Leaks	88	87	109	108	104	102	101
Gas Engines	86	70	93	93	90	89	91
Chemical Injection Pumps	49	68	88	87	84	82	81
Tanks	217	60	63	68	101	61	57
Other Sources	105	86	131	131	92	103	127
Crude Oil Transportation	**7**	**5**	**8**	**8**	**8**	**8**	**8**
Refining	**27**	**31**	**31**	**33**	**33**	**33**	**31**
Total	**1,844**	**1,553**	**1,739**	**1,622**	**1,559**	**1,548**	**1,449**

Note: Totals may not sum due to independent rounding.
[a] Exploration includes well drilling, testing, and completions.

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

Activity	1990	2005	2014	2015	2016	2017	2018
Exploration	0.3	0.3	3.1	2.2	1.2	1.6	2.8
Production	6.0	8.1	24.1	26.4	17.8	19.2	30.3
Transportation	+	+	+	+	+	+	+
Crude Refining	3.3	3.7	3.4	4.1	4.0	3.7	3.7
Total	**9.6**	**12.2**	**30.5**	**32.6**	**23.0**	**24.5**	**36.8**

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

Table 3-40: CO_2 Emissions from Petroleum Systems (kt CO_2)

Activity	1990	2005	2014	2015	2016	2017	2018
Exploration	330	348	3,060	2,221	1,233	1,566	2,761
Production	6,014	8,087	24,056	26,355	17,755	19,190	30,317
Transportation	0.9	0.7	1.2	1.2	1.1	1.1	1.2
Crude Refining	3,284	3,728	3,419	4,067	3,991	3,714	3,734
Total	**9,630**	**12,163**	**30,536**	**32,644**	**22,980**	**24,472**	**36,814**

Note: Totals may not sum due to independent rounding.

Table 3-41: N_2O Emissions from Petroleum Systems (metric tons CO_2 Eq.)

Activity	1990	2005	2014	2015	2016	2017	2018
Exploration	172	178	1,563	1,139	628	690	1,623
Production	7,483	8,173	18,464	20,329	15,341	15,466	58,809
Transportation	NE	NE	NE	NE	NE	NE	NE
Crude Refining	9,138	10,372	9,659	11,656	11,575	10,796	10,557
Total	**16,793**	**18,723**	**29,686**	**33,124**	**27,544**	**26,951**	**70,988**

Note: Totals may not sum due to independent rounding.
NE (Not Estimated)

Table 3-42: N_2O Emissions from Petroleum Systems (metric tons N_2O)

Activity	1990	2005	2014	2015	2016	2017	2018
Exploration	0.6	0.6	5.2	3.8	2.1	2.3	5.4
Production	25.1	27.4	62.0	68.2	51.5	51.9	197.3

Transportation	NE	NE	NE	NE	NE	NE	NE
Crude Refining	30.7	34.8	32.4	39.1	38.8	36.2	35.4
Total	**56.4**	**62.8**	**99.6**	**111.2**	**92.4**	**90.4**	**238.2**

Note: Totals may not sum due to independent rounding.
NE (Not Estimated)

Methodology

See Annex 3.5 for the full time series of emissions data, activity data, and emission factors, and additional information on methods and data sources.

Petroleum systems includes emission estimates for activities occurring in petroleum systems from the oil wellhead through crude oil refining, including activities for crude oil exploration, production field operations, crude oil transportation activities, and refining operations. Generally, 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).

EPA received stakeholder feedback on updates in the Inventory through EPA's stakeholder process on oil and gas in the Inventory. Stakeholder feedback is noted below in Recalculations Discussion and Planned Improvements. More information on the stakeholder process can be found here: https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems.

Emission Factors. References for emission factors include *Methane Emissions from the Natural Gas Industry by the Gas Research Institute and EPA* (GRI/EPA 1996), *Estimates of Methane Emissions from the U.S. Oil Industry* (EPA 1999), *Compilation of Air Pollutant Emission Factors, AP-42* (EPA 1997), *Global Emissions of Methane from Petroleum Sources* (API 1992), consensus of industry peer review panels, Bureau of Ocean Energy Management (BOEM) reports, and analysis of GHGRP data (EPA 2019).

Emission factors for hydraulically fractured (HF) oil well completions and workovers (in four control categories) were developed using GHGRP data; year-specific data were used to calculate emission factors from 2016-forward and the year 2016 emission factors were applied to all prior years in the time series. The emission factors for all years for pneumatic controllers and chemical injection pumps were developed using GHGRP data for reporting year 2014. The emission factors for tanks, well testing, and associated gas venting and flaring were developed using year-specific GHGRP data for years 2015 forward; earlier years in the time series use 2015 emission factors. For miscellaneous production flaring, year-specific emission factors were developed for years 2015 forward from GHGRP data, an emission factor of 0 (assumption of no flaring) was assumed for 1990 through 1992, and linear interpolation was applied to develop emission factors for 1993 through 2014. For more information please see memoranda available online.[77] For offshore oil production, emission factors were calculated using BOEM data for offshore facilities in federal waters of the Gulf of Mexico (and these data were also applied to facilities located in state waters of the Gulf of Mexico) and GHGRP data for offshore facilities off the coasts of California and Alaska. For many other sources, emission factors were held constant for the period 1990 through 2018, and trends in emissions reflect changes in activity levels. Emission factors from EPA 1999 are used for all other production and transportation activities.

For associated gas venting and flaring and miscellaneous production flaring, emission factors were developed on a production basis (i.e., emissions per unit oil produced). Additionally, for these two sources, basin-specific activity and emission factors were developed for each basin that in any year from 2011 forward contributed at least 10 percent of total source emissions (on a CO_2 Eq. basis) in the GHGRP. For associated gas venting and flaring, basin-specific factors were developed for four basins: Williston, Permian, Gulf Coast, and Anadarko; for miscellaneous production flaring, basin-specific factors were developed for three basins: Williston, Permian, and Gulf Coast. Data

[77] See <https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems>.

from all other basins were combined, and activity and emission factors developed for the other basins as a single group for each emission source.

For the exploration and production segments, in general, CO_2 emissions for each source were estimated with GHGRP data or by multiplying CO_2 content factors by the corresponding CH_4 data, as the CO_2 content of gas relates to the CH_4 content of gas. Sources with CO_2 emission estimates calculated using GHGRP data were HF completions and workovers, associated gas venting and flaring, tanks, well testing, pneumatic controllers, chemical injection pumps, miscellaneous production flaring, and certain offshore production facilities (those located off the coasts of California and Alaska). For these sources, CO_2 was calculated using the same methods as used for CH_4. Carbon dioxide emission factors for offshore oil production in the Gulf of Mexico were derived using data from BOEM, following the same methods as used for CH_4 estimates. For other sources, 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.

For the exploration and production segments, N_2O emissions were estimated for flaring sources using GHGRP data. Sources with N_2O emissions in the exploration segment were well testing and HF completions with flaring. Sources with N_2O emissions in the production segment were associated gas flaring, tank flaring, miscellaneous production flaring, and HF workovers with flaring.

For crude oil transportation, emission factors for CH_4 were largely developed using data from EPA (1997), API (1992), and EPA (1999). Emission factors for CO_2 were 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 whole crude post-separator.

For petroleum refining activities, year-specific emissions from 2010 forward were directly obtained from EPA's GHGRP. All U.S. refineries have been required to report CH_4, CO_2, and N_2O emissions for all major activities starting with emissions that occurred in 2010. The reported total of CH_4, CO_2, and N_2O emissions for each activity was used for the emissions in each year from 2010 forward. To estimate emissions for 1990 to 2009, the 2010 to 2013 emissions data from GHGRP along with the refinery feed data for 2010 to 2013 were used to derive CH_4 and CO_2 emission factors (i.e., sum of activity emissions/sum of refinery feed) and 2010 to 2017 data were used to derive N_2O emission factors, which were then applied to the annual refinery feed in years 1990 to 2009. GHGRP delayed coker CH_4 emissions for 2010 through 2017 were increased using the ratio of certain reported emissions for 2018 to 2017, to account for a more accurate GHGRP calculation methodology that was implemented starting in reporting year 2018.

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

Activity Data. References for activity data include DrillingInfo data (Enverus DrillingInfo 2019), Energy Information Administration (EIA) reports, *Methane Emissions from the Natural Gas Industry by the Gas Research Institute and EPA* (EPA/GRI 1996), *Estimates of Methane Emissions from the U.S. Oil Industry* (EPA 1999), consensus of industry peer review panels, BOEM reports, the Oil & Gas Journal, the Interstate Oil and Gas Compact Commission, the United States Army Corps of Engineers, and analysis of GHGRP data (EPA 2019).

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/GRI 1996 and/or GHGRP data. In some cases, activity data are developed by interpolating between recent data points (such as from GHGRP) and earlier data points, such as from EPA/GRI 1996. Lastly, in limited instances the previous year's data were used if current year were not yet available.

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

Uncertainty and Time-Series Consistency

EPA conducted a quantitative uncertainty analysis using the IPCC Approach 2 methodology (Monte Carlo Simulation technique) to characterize uncertainty for petroleum systems. For more information on the approach,

please see the memorandum Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2016: Natural Gas and Petroleum Systems Uncertainty Estimates (2018 Uncertainty Memo).[78]

EPA used Microsoft Excel's @RISK add-in tool to estimate the 95 percent confidence bound around methane emissions from petroleum systems for the current Inventory, then applied the calculated bounds to both CH_4 and CO_2 emissions estimates. Uncertainty estimates for N_2O were not developed given the minor contribution of N_2O to emission totals. For the analysis, EPA focused on the six highest methane-emitting sources for the year 2018, which together emitted 75 percent of methane from petroleum systems in 2018, and extrapolated the estimated uncertainty for the remaining sources. The @RISK add-in provides for the specification of probability density functions (PDFs) for key variables within a computational structure that mirrors the calculation of the inventory estimate. The IPCC guidance notes that in using this method, "some uncertainties that are not addressed by statistical means may exist, including those arising from omissions or double counting, or other conceptual errors, or from incomplete understanding of the processes that may lead to inaccuracies in estimates developed from models." As a result, the understanding of the uncertainty of emission estimates for this category evolves and improves as the underlying methodologies and datasets improve. The uncertainty bounds reported below only reflect those uncertainties that EPA has been able to quantify and do not incorporate considerations such as modeling uncertainty, data representativeness, measurement errors, misreporting or misclassification.

The results presented below provide the 95 percent confidence bound within which actual emissions from this source category are likely to fall for the year 2018, using the recommended IPCC methodology. The results of the Approach 2 uncertainty analysis are summarized in Table 3-43. Petroleum systems CH_4 emissions in 2018 were estimated to be between 25.0 and 48.4 MMT CO_2 Eq., while CO_2 emissions were estimated to be between 25.4 and 49.3 MMT CO_2 Eq. at a 95 percent confidence level. Uncertainty bounds for other years of the time series have not been calculated, but uncertainty is expected to vary over the time series. For example, years where many emission sources are calculated with interpolated data would likely have higher uncertainty than years with predominantly year-specific data.

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

Source	Gas	2018 Emission Estimate (MMT CO_2 Eq.)[b]	Uncertainty Range Relative to Emission Estimate[a] (MMT CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Petroleum Systems	CH_4	36.2	25.0	48.4	-31%	+34%
Petroleum Systems[c]	CO_2	36.8	25.4	49.2	-31%	+34%

[a] Range of emission estimates estimated by applying the 95 percent confidence intervals obtained from the Monte Carlo Simulation analysis conducted for the year 2018 CH_4 emissions.

[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.

[c] An uncertainty analysis for the petroleum systems 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 petroleum systems CO_2 emissions.

GHGRP 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 datasets were collected in the 1990s. To develop a consistent time series 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 through 2009 or 2014 by interpolating activity data or emission factors or both between 1992 (when GRI/EPA data are available) and 2010 or 2015 data points. Information on time-series consistency for sources updated in this year's Inventory can be found in the Recalculations Discussion below, with additional detail provided in supporting memos (relevant

[78] See <https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems>.

memos are cited in the Recalculations Discussion). For information on other sources, please see the Methodology Discussion above and Annex 3.5.

QA/QC and Verification Discussion

The petroleum systems 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. 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, EPA follows up with facilities to resolve mistakes that may have occurred.[79]

As in previous years, EPA conducted early engagement and communication with stakeholders on updates prior to public review. EPA held a stakeholder webinar on greenhouse gas data for oil and gas in September of 2019, and a workshop in November of 2019. EPA released memos detailing updates under consideration and requesting stakeholder feedback. 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 the Emissions Database for Global Atmospheric Research, or "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 detailed scale-dependent error characterization.[80] The gridded methane inventory is designed to be consistent with the U.S. EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2014* estimates for the year 2012, which presents national totals.[81]

As discussed above, refinery emissions are quantified by using the total emissions reported to GHGRP for the refinery emission categories included in Petroleum Systems. Subpart Y has provisions that refineries are not required to report under Subpart Y if their emissions fall below certain thresholds. Each year, a review is conducted to determine whether an adjustment is needed to the Inventory emissions to include emissions from refineries that stopped reporting to the GHGRP. The 2018 GHGRP data indicates that 2 refineries stopped reporting in 2018 (i.e., 2017 is the last reported year). One of them permanently shutdown towards the end of 2017 and the other one did not report in 2018 due to a merger. Based on this assessment, cessation of reporting does not impact the

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

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

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

completeness of data for 2018 refinery emissions and therefore no adjustment has been made to these estimates for the Inventory.

Recalculations Discussion

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 September 2019, EPA released a draft memorandum that discussed changes under consideration and requested stakeholder feedback on those changes. EPA then created an updated version of the memorandum to document the methodology implemented into the current Inventory.[82] The EPA memorandum *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2018: Update for Offshore Production Emissions* (*Offshore Production* memo) is cited in the Recalculations Discussion below.

EPA thoroughly evaluated relevant information available and made updates to production and refinery segment methodologies for the Inventory, specifically: using updated BOEM, GHGRP, and other data to calculate emissions and activity factors for offshore oil production, and revisiting emissions data for delayed coking in refineries to be consistent with changes to Subpart Y. In addition, certain sources did not undergo methodological updates, but CH_4 and/or CO_2 emissions changed by greater than 0.05 MMT CO_2 Eq., comparing the previous estimate for 2017 to the current (recalculated) estimate for 2017 (the emissions changes were mostly due to GHGRP data submission revisions); these sources are discussed below and include hydraulically fractured oil well completions and workovers, associated gas flaring, miscellaneous production flaring, and pneumatic controllers.

The combined impact of revisions to 2017 petroleum systems CH_4 emission estimates, compared to the previous Inventory, is an increase from 37.7 to 38.7 MMT CO_2 Eq. (1.0 MMT CO_2 Eq., or 3 percent). The recalculations resulted in an average increase in CH_4 emission estimates across the 1990 through 2017 time series, compared to the previous Inventory, of 3.5 MMT CO_2 Eq., or 9 percent, with the largest increase being in the estimate for 1996 (5.2 MMT CO_2 Eq. or 14 percent) due to the recalculations for offshore oil production.

The combined impact of revisions to 2017 petroleum systems CO_2 emission estimates, compared to the previous Inventory, is an increase from 23.3 to 24.5 MMT CO_2 (1.1 MMT CO_2, or 5 percent). The recalculations resulted in an average increase in emission estimates across the 1990 through 2017 time series, compared to the previous Inventory, of 0.8 MMT CO_2 Eq., or 6 percent with the largest changes being for 2017 (1.1 MMT CO_2 or 5 percent) due to the recalculations for offshore oil production.

The combined impact of revisions to 2017 petroleum systems N_2O emission estimates, compared to the previous Inventory, is an increase of 0.003 MMT CO_2, Eq. or 11 percent. The recalculations resulted in an average increase in emission estimates across the 1990 through 2017 time series, compared to the previous Inventory, of 0.003 MMT CO_2 Eq., or 19 percent.

In Table 3-44 and Table 3-45 below are categories in Petroleum Systems with updated methodologies or with recalculations resulting in a change of greater than 0.05 MMT CO_2 Eq., comparing the previous estimate for 2017 to the current (recalculated) estimate for 2017. For more information, please see the Recalculations Discussion below.

Table 3-44: Recalculations of CO_2 in Petroleum Systems (MMT CO_2)

	Previous Estimate Year 2017, 2019 Inventory	**Current Estimate Year 2017, 2020 Inventory**	**Current Estimate Year 2018, 2020 Inventory**
Exploration	***1.7***	**1.6**	**2.8**
HF Oil Well Completions	*1.6*	1.5	2.7
Production	***18.0***	**19.2**	**30.3**

[82] Stakeholder materials including draft and final memoranda for the current (i.e., 1990 to 2018) Inventory are available at <https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems>.

Offshore Oil Production	*+*	0.5	0.5
Associated Gas Venting & Flaring	*10.5*	10.9	19.0
Miscellaneous Flaring	*2.6*	3.1	4.2
HF Oil Well Workovers	*0.3*	0.2	0.1
Transportation	***+***	**+**	**+**
Refining	***3.7***	**3.7**	**3.7**
Petroleum Systems Total	***23.3***	**24.5**	**36.8**

+ Does not exceed 0.05 MMT CO_2.

Table 3-45: Recalculations of CH_4 in Petroleum Systems (MMT CO_2 Eq.)

	Previous Estimate Year 2017, 2019 Inventory	Current Estimate Year 2017, 2020 Inventory	Current Estimate Year 2018, 2020 Inventory
Exploration	***0.4***	**0.3**	**0.4**
Production	***36.4***	**37.4**	**34.9**
Pneumatic Controllers	*20.9*	21.3	18.4
Offshore Oil Production	*4.7*	5.1	5.1
Transportation	***0.2***	**0.2**	**0.2**
Refining	***0.7***	**0.8**	**0.8**
Delayed Cokers	*+*	0.1	0.1
Petroleum Systems Total	***37.7***	**38.7**	**36.2**

+ Does not exceed 0.05 MMT CO_2 Eq.

Exploration

HF Oil Well Completions (Recalculation with Updated Data)

HF oil well completion CO_2 emissions increased by an average of 9 percent across the time series and decreased by 6 percent in 2017, compared the to the previous Inventory. The CO_2 emissions changes are due to GHGRP data submission revisions. The recalculation of the EF for non-REC with flaring HF oil well completions had the largest impact on times series emissions. Compared to the previous Inventory, the EF for non-REC with flaring increased by 13 percent for all years of the time series except 2017; in 2017 it decreased by 6 percent.

Table 3-46: HF Oil Well Completions National CO_2 Emissions (kt CO_2)

Source	1990	2005	2014	2015	2016	2017	2018
HF Completions: Non-REC with Venting	2.5	4.0	4.0	1.4	0.2	0.2	+
HF Completions: Non-REC with Flaring	89	139	690	446	252	360	552
HF Completions: REC with Venting	0.0	0.0	0.2	0.2	0.1	0.1	0.1
HF Completions: REC with Flaring	0.0	0.0	2,107	1,518	940	1,168	2,178
Total Emissions	**92**	**143**	**2,801**	**1,966**	**1,192**	**1,529**	**2,730**
Previous Estimate	*81*	*127*	*2,719*	*1,913*	*1,162*	*1,619*	*NA*

+ Does not exceed 0.05 kt CO_2.
NA (Not Applicable)

Production

Offshore Oil Production (Methodological Update)

EPA updated the offshore production methodology to estimate emissions for all offshore producing regions and to use activity data sources that provide a full time series of data. The previous Inventory only estimated emissions for offshore facilities in federal waters of the Gulf of Mexico (GOM); these facilities are under Bureau of Ocean Energy Management (BOEM) jurisdiction and BOEM estimates their greenhouse gas emissions triennially via the Gulfwide Emissions Inventory (GEI). The previous Inventory also relied on activity data sources that were no longer updated, and surrogate activity data from 2008 and 2010 had been used to estimate emissions in more recent years. The updated Inventory methodology now includes emissions estimates for offshore facilities in federal and state waters of the GOM and offshore facilities in the Pacific and off the coast of Alaska.

The updated Inventory methodology for each region is presented here. EPA calculated vent and leak EFs for offshore facilities in GOM federal waters for major complexes and minor complexes using BOEM GEI emissions data from the 2005, 2008, 2011, 2014, and 2017 GEIs. Vent and leak EFs were calculated for 10 emission sources (cold vents, equipment leaks, pneumatic pumps, losses from flashing, pneumatic controllers, combustion, glycol hydrators, storage tanks, mud degassing, minor surrogates, and amine gas sweetening units) and paired with active offshore complex counts over the time series. EPA calculated GOM federal waters flaring emissions using flaring volumes reported in Oil and Gas Operations Reports (OGOR), Part B (OGOR-B). OGOR-B flaring volumes are available over the time series but assumptions were necessary to assign the volumes to offshore gas production versus offshore oil production for 1990 to 2010. The previous Inventory allocated all GOM federal waters flaring emissions to offshore gas production facilities. EPA calculated production based EFs for offshore facilities in GOM state waters using the resulting GOM federal waters emissions and oil production in each year. EPA also calculated production based EFs for offshore facilities in the Pacific and Alaska regions, though the EFs for these regions were derived from GHGRP data. EPA multiplied the production based EFs by the region-specific offshore production (i.e., GOM state waters production, Pacific production, and Alaska production) in a given year. The *Offshore Production* memo provides details for the methodology update that was implemented into the Inventory.

Due to this recalculation, annual offshore oil production CH_4 emission estimates increased in the current Inventory for 1990 to 2017 by an average of 67 percent, compared to the previous Inventory. The impacts varied across the time series with estimates in 1990 through 2009 increasing by an average of84 percent and estimates in 2010 through 2017 increasing by an average of 25 percent. The increase in offshore oil production CH_4 emission estimates over the time series are due in part to the inclusion of emissions from facilities located in GOM state waters and the Pacific and Alaska regions. The increase in offshore oil production CH_4 emission estimates for 1990 to 2009 also resulted from an increase in calculated emissions for GOM federal waters due to differences in EFs and activity data between the current and previous Inventory. The current Inventory applied EFs calculated from 2008 GEI data for this time period, whereas the previous Inventory applied EFs calculated from 2011 GEI data for this time period and the 2008 GEI CH_4 emissions are higher. There are more offshore oil facilities in the current Inventory compared to the previous Inventory. The current and previous Inventories have a different activity basis (i.e., offshore complexes versus offshore structures), but a much higher percentage of offshore facilities in the current Inventory are classified as oil rather than gas (an average of 66 percent oil facilities for 1990 through 2009) compared to the previous Inventory (an average of 41 percent oil facilities over the same time period).

For comparison, total offshore production (for oil and gas combined) CH_4 emissions for facilities in GOM federal waters are provided here for years 2011, 2014, and 2017 from the GEI, previous Inventory, and current Inventory. For offshore facilities in GOM federal waters in year 2011, GEI CH_4 emissions equaled 246 kt, previous Inventory CH_4 emissions equaled 338 kt, and current Inventory CH_4 emissions equal 278 kt. For offshore facilities in GOM federal waters in year 2014, GEI CH_4 emissions equaled 205 kt, previous Inventory CH_4 emissions equaled 338 kt, and current Inventory CH_4 emissions equal 225 kt. For offshore facilities in GOM federal waters in year 2017, GEI CH_4 emissions equaled 170 kt, previous Inventory CH_4 emissions equaled 338 kt, and current Inventory CH_4 emissions equal 206 kt.

Annual offshore oil production CO_2 emission estimates increased in the current Inventory for 1990 to 2017 by a factor of 72 on average, compared to the previous Inventory. This change is largely because all GOM federal waters flaring emissions in the previous Inventory were allocated to offshore gas production, whereas the current Inventory estimates GOM federal waters flaring emissions for both offshore gas and oil production, and a significant portion of the CO_2 is from offshore oil production. In addition, the Alaska region (which was not

previously included) is a significant contributor to CO_2 emissions, due to flaring, and accounts for the highest fraction of CO_2 emissions from 1990 through 2007 in the current Inventory.

EPA received feedback on this update through its September 2019 memo and through the public review draft of the Inventory. Two stakeholders supported the update to activity data. A stakeholder suggested clarifications on the calculation of emission factors, and noted upcoming data that may be used to assess offshore emission factors. A stakeholder suggested clarification on the development of activity counts and supported considering a different approach which would use source-specific emission factors. As noted above, the emissions estimates were calculated using complex-level factors for offshore operations in GOM federal waters, and using production-based emission factors for offshore operations in state waters. An estimate of emissions source-level emissions was developed using the fraction of emissions in each category in the GOM federal waters data set, applied to GOM federal and state water total emission estimates, and using the fraction of emissions in each category in GHGRP for Pacific and Alaska offshore production, and applied to the total estimates for Pacific and Alaska offshore production. The emission source-level estimates are available in the annex. The stakeholder noted that the use of emission factors calculated from data from the from the GHGRP reporting population (those emitting over the GHGRP threshold), applied to all Pacific and Alaska offshore production could skew regional emission estimates. The stakeholder also supported the use of GEI data as opposed to OGOR-B data to calculate emissions from flaring. The emissions estimates were calculated using OGOR-B. GEI data is currently available for the years 2005, 2008, 2011, 2014, and 2017. The OGOR-B dataset can be used to calculate flaring emissions for the full 1990 to 2018 time series.

The recalculation also results in a change in the trend, in methane in particular where the 1990 to 2017 trend in this Inventory is a decrease of 45 percent, versus a decrease of 11 percent in the previous Inventory. A stakeholder provided several factors supporting this decreasing trend: more stringent limitations imposed by BSEE (Bureau of Safety and Environmental Enforcement) related to venting and flaring, increased utilization of VRU equipment, and replacement of older platforms with newer ones that include state of the art technology.

Table 3-47: Offshore Oil Production National CH_4 Emissions (metric tons CH_4)

Source	1990	2005	2014	2015	2016	2017	2018
GOM Federal Waters	303,520	219,422	203,201	197,233	189,145	186,806	186,138
GOM State Waters	24,302	2,860	2,381	1,979	1,655	1,222	1,130
Pacific Waters	22,610	17,660	13,790	10,308	5,008	5,052	5,163
Alaska State Waters	21,936	21,192	10,516	10,703	9,680	12,164	9,834
Total Emissions	**372,368**	**261,133**	**229,888**	**220,223**	**205,488**	**205,243**	**202,265**
Previous Estimate	*210,938*	*185,023*	*187,604*	*187,604*	*187,604*	*187,604*	*NA*

NA (Not Applicable)

Table 3-48: Offshore Oil Production National CO_2 Emissions (metric tons CO_2)

Source	1990	2005	2014	2015	2016	2017	2018
GOM Federal Waters	188,356	147,743	313,103	368,773	373,468	379,413	414,023
GOM State Waters	15,081	1,926	3,669	3,700	3,269	2,482	2,514
Pacific Waters	70,319	54,925	42,889	32,060	11,052	13,440	8,688
Alaska State Waters	357,965	345,809	171,607	174,652	122,554	119,963	122,362
Total Emissions	**631,721**	**550,402**	**531,267**	**579,185**	**510,342**	**515,299**	**547,587**
Previous Estimate[a]	*9,604*	*8,283*	*8,340*	*8,340*	*8,340*	*8,340*	*NA*

NA (Not Applicable)

[a] Includes only CO_2 from leaks and vents.

HF Oil Well Workovers (Recalculation with Updated Data)

HF oil well workover CO_2 emissions increased by an average of 8 percent across the time series, and decreased by 30 percent in 2017, compared the to the previous Inventory. The CO_2 emissions changes are due to GHGRP data submission revisions, which resulted in a recalculation of emission factors and activity data. HF oil well workover CO_2 time series emissions were most impacted by the recalculation of the EF for non-REC HF oil well workovers

with flaring, which increased by 13 percent for 1990 to 2016 (compared to the previous Inventory). The recalculation of activity data for REC HF oil well workovers with flaring had the largest impact on year 2017 emissions, with a smaller fraction of the population using REC with flaring.

Table 3-49: HF Oil Well Workovers National CO_2 Emissions (kt CO_2)

Source	1990	2005	2014	2015	2016	2017	2018
HF Workovers: Non-REC with Venting	0.7	0.8	0.4	0.2	0.1	0.0	+
HF Workovers: REC with Venting	0.0	0.0	+	+	0.1	+	+
HF Workovers: Non-REC with Flaring	25.1	28.3	36.6	35.2	32.2	18.2	3.6
HF Workovers: REC with Flaring	0.0	0.0	133.1	157.8	175.6	160.8	89.3
Total Emissions	**25.8**	**29.1**	**170.1**	**193.3**	**207.8**	**179.0**	**92.9**
Previous Estimate	*22.9*	*25.8*	*168.3*	*192.1*	*207.4*	*257.5*	*NA*

+ Does not exceed 0.05 kt CO_2.
NA (Not Applicable)

Pneumatic Controllers (Recalculation with Updated Data)

Pneumatic controller CH_4 emission estimates increased by an average of less than 1 percent across the 1990 to 2017 time series, compared to the previous Inventory, due to GHGRP submission revisions and a small increase in well counts throughout the time series due to updated Drilling Info data.

Table 3-50: Pneumatic Controller National CH_4 Emissions (Metric Tons CH_4)

Source	1990	2005	2014	2015	2016	2017	2018
Pneumatic Controllers: High Bleed	722,968	420,444	88,574	78,213	82,555	52,608	39,088
Pneumatic Controllers: Low Bleed	49,343	44,058	28,772	25,461	17,517	19,651	30,628
Pneumatic Controllers: Int Bleed	0.0	239,899	665,830	685,810	722,917	778,365	665,108
Total Emissions	**772,311**	**704,401**	**783,176**	**789,484**	**822,989**	**850,624**	**734,824**
Previous Estimate	*773,655*	*700,990*	*776,512*	*785,704*	*818,169*	*836,804*	*NA*

NA (Not Applicable)

Associated Gas Flaring (Recalculation with Updated Data)

Associated gas flaring CO_2 emission estimates increased by an average of 2 percent across the time series in the current Inventory, compared to the previous Inventory. This change was due to GHGRP submission revisions. The changes in CO_2 emissions for 2017 (the year with the largest change) were mainly driven by the Williston and Permian Basin data.

Table 3-51: Associated Gas Flaring National CO_2 Emissions (kt CO_2)

Source	1990	2005	2014	2015	2016	2017	2018
220 - Gulf Coast Basin (LA, TX)	234	127	631	673	404	740	686
360 - Anadarko Basin	108	65	230	238	2	57	37
395 - Williston Basin	966	1,239	7,799	8,412	5,838	6,530	10,132
430 - Permian Basin	2,983	2,046	3,869	4,443	2,246	3,148	7,249
"Other" Basins	925	499	520	544	326	414	876
Total Emissions	**5,217**	**3,977**	**13,050**	**14,311**	**8,815**	**10,889**	**18,980**
220 - Gulf Coast Basin (LA, TX)	*233*	*126*	*631*	*673*	*350*	*688*	*NA*
360 - Anadarko Basin	*106*	*65*	*222*	*239*	*2*	*55*	*NA*
395 - Williston Basin	*925*	*1,186*	*7,466*	*8,052*	*5,662*	*6,451*	*NA*
430 - Permian Basin	*2,982*	*2,048*	*3,869*	*4,447*	*2,247*	*2,897*	*NA*
"Other" Basins	*927*	*499*	*523*	*544*	*325*	*416*	*NA*

Previous Estimate	*5,172*	*3,925*	*12,711*	*13,955*	*8,587*	*10,506*	*NA*

NA (Not Applicable)

Miscellaneous Production Flaring (Recalculation with Updated Data)

Miscellaneous production flaring CO_2 emission estimates increased by 17 percent in 2017 and increased by less than 1 percent for other years of the time series, compared to the previous Inventory. The 2017 increase was primarily due to recalculations of CO_2 from flaring in the Permian and Williston basins, where GHGRP resubmission revisions showed higher CO_2 emissions from flaring, by 65 and 20 percent, respectively.

Table 3-52: Miscellaneous Production Flaring National CO_2 Emissions (kt CO_2)

Source	1990	2005	2014	2015	2016	2017	2018
220 - Gulf Coast Basin (LA, TX)	0	106	893	997	497	526	687
395 - Williston Basin	0	73	782	882	315	531	1,653
430 - Permian Basin	0	215	687	825	794	1,424	1,183
Other Basins	0	407	796	870	592	585	703
Total Emissions	**0**	**801**	**3,159**	**3,573**	**2,198**	**3,066**	**4,226**
220 - Gulf Coast Basin (LA, TX)	*0*	*107*	*901*	*1,005*	*496*	*523*	*NA*
395 - Williston Basin	*0*	*73*	*776*	*875*	*309*	*321*	*NA*
430 - Permian Basin	*0*	*215*	*686*	*824*	*794*	*1,185*	*NA*
Other Basins	*0*	*406*	*794*	*867*	*601*	*601*	*NA*
Previous Total Estimate	*0*	*800*	*3,157*	*3,571*	*2,201*	*2,631*	*NA*

NA (Not Applicable)

Well Counts (Recalculation with Updated Data)

For total national well counts, EPA has used a more recent version of the DrillingInfo dataset (Enverus DrillingInfo 2019) to update well counts data in the Inventory. While this is not a significant recalculation (the update results in an average increase of less than 1 percent), the well count dataset is a key input to the Inventory, and results are highlighted here.

Table 3-53: Producing Oil Well Count Data

Oil Well Count	1990	2005	2014	2015	2016	2017	2018
Number of Oil Wells	562,356	482,887	610,121	600,519	580,917	570,331	564,186
Previous Estimate	564,090	480,482	605,259	597,635	577,515	566,726	NA

NA (Not Applicable)

In December 2019, EIA released an updated time series of national oil and gas well counts (covering 2000 through 2018). EIA estimates 982,371 total producing wells for year 2018. EPA's total well count for this year is 969,212. EPA's well counts in recent time series years are generally 1 percent lower than EIA's. EIA's well counts include side tracks, completions, and recompletions, and therefore are expected to be higher than EPA's which include only producing wells. EPA and EIA use a different threshold for distinguishing between oil versus gas (EIA uses 6 mcf/bbl, while EPA uses 100 mcf/bbl), which results in EIA having a lower fraction of oil wells and a higher fraction of gas wells than EPA.

Refining

Refinery CH_4 emissions increased by an average of 12 percent across the time series, compared to the previous Inventory, due to a recalculation of delayed coker emissions. The Subpart Y calculation methodology for delayed cokers was updated for reporting year 2018 to use more accurate methods to quantify emissions for delayed cokers. The update to the calculation methodology resulted in higher reported emissions from delayed cokers in

2018 compared to previous years of reporting. The update did not impact all facilities in Subpart Y as some facilities had already been reporting using the more accurate methods. For time-series consistency across 1990 to 2018 in the Inventory, emission estimates were updated for 1990 through 2017 using a ratio of reported emissions for 2018 to 2017, comparing facilities that used different methods for those years. A stakeholder supported this approach to updating estimates for delayed coker emissions.

Table 3-54: Refineries National CH_4 Emissions (metric tons CH_4)

Source	1990	2005	2014	2015	2016	2017	2018
Delayed Cokers	3,873	4,395	5,506	5,447	5,787	5,142	5,435
Other Refining Sources	23,299	26,445	25,089	27,294	27,245	27,992	25,503
Total Refinery Emissions	**27,172**	**30,841**	**30,595**	**32,742**	**33,032**	**33,134**	**30,938**
Previous Delayed Cokers	*1,146*	*1,301*	*1,057*	*931*	*960*	*1,029*	*NA*
Previous Other Refining Sources	*23,294*	*26,440*	*24,979*	*27,271*	*27,171*	*27,305*	*NA*
Previous Total Refinery Estimate	*24,440*	*27,740*	*26,036*	*28,202*	*28,131*	*28,333*	*NA*

NA (Not Applicable)

Planned Improvements

Offshore Production

EPA updated the offshore production methodology for the Inventory, incorporating data from BOEM and GHGRP. Detailed information and considerations for various approaches considered for the methodology update were provided in a memorandum and discussed at a stakeholder workshop and webinar. Through the stakeholder process and the public review period, stakeholders provided feedback on additional approaches or data sets that could be used. In future inventories, EPA will consider alternate approaches or data sources, such as additional use of BOEM data or data from upcoming studies. Stakeholders identified upcoming studies of offshore oil and gas platform emissions that will include evaluation of different inventory estimates and methods.

Upcoming Data, and Additional Data that Could Inform the Inventory

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 (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, in recent years, stakeholder comments have highlighted areas where additional data that could inform the Inventory are currently limited or unavailable:

- Tank malfunction and control efficiency data.
- Activity data and emissions data for production facilities that do not report to GHGRP.
- Associated gas venting and flaring data on practices from 1990 through 2010.
- Refineries emissions data.
- Anomalous leak events.

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

Box 3-6: 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.

For EOR CO_2, as noted in the *2006 IPCC Guidelines*, "At the Tier 1 or 2 methodology levels [EOR CO_2 is] indistinguishable from fugitive greenhouse gas emissions by the associated oil and gas activities." In the U.S. estimates for oil and gas fugitive emissions, the Tier 2 emission factors for CO_2 include CO_2 that was originally injected and is emitted along with other gas from leak, venting, and flaring pathways, as measurement data used to develop those factors would not be able to distinguish between CO_2 from EOR and CO_2 occurring in the produced natural gas. Therefore, EOR CO_2 emitted through those pathways is included in CO_2 estimates in 1B2.

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.

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 2018. However, for 2015 through 2018, data from EPA's GHGRP (Subpart PP) were held constant from 2014 levels, for data confidentiality reasons. EPA will continue to evaluate the availability of additional GHGRP data and other opportunities for improving the estimates. Several facilities are reporting under Subpart RR (Geologic Sequestration of Carbon Dioxide). In 2016, one facility reported 3.1 MMT of CO_2 sequestered in subsurface geological formations and 9,818 metric tons of CO_2 emitted from equipment leaks. In 2017, three facilities reported 9.1 MMT of CO_2 sequestered in subsurface geological formations, and 9,577 metric tons of CO_2 emitted from equipment leaks. In 2018, five facilities reported 16.7 MMT of CO_2 sequestered in subsurface geological formations and 11,023 metric tons of CO_2 emitted from equipment leaks.

The amount of CO_2 captured and extracted from natural and industrial sites for EOR applications in 2018 is 59.3 MMT CO_2 Eq. (59,318 kt) (see Table 3-55 and Table 3-56). 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 3-55: Quantity of CO_2 Captured and Extracted for EOR Operations (MMT CO_2)

Stage	1990	2005	2014	2015	2016	2017	2018
Capture Facilities	4.8	6.5	13.1	13.1	13.1	13.1	13.1
Extraction Facilities	20.8	28.3	46.2	46.2	46.2	46.2	46.2
Total	**25.6**	**34.7**	**59.3**	**59.3**	**59.3**	**59.3**	**59.3**

Note: Totals may not sum due to independent rounding.

Table 3-56: Quantity of CO_2 Captured and Extracted for EOR Operations (kt)

Stage	1990	2005	2014	2015	2016	2017	2018
Capture Facilities	4,832	6,475	13,093	13,093	13,093	13,093	13,093
Extraction Facilities	20,811	28,267	46,225	46,225	46,225	46,225	46,225
Total	**25,643**	**34,742**	**59,318**	**59,318**	**59,318**	**59,318**	**59,318**

Note: Totals may not sum due to independent rounding.

3.7 Natural Gas Systems (CRF 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. This IPCC category (1B2b) is for fugitive emissions, which per IPCC include emissions from leaks, venting, and flaring. Total greenhouse gas emissions (CH_4, CO_2, and N_2O) from natural gas systems in 2018 were 174.9 MMT CO_2 Eq., a decrease of 19 percent from 1990, primarily due to decreases in CH_4 emissions, and an increase of 3 percent from 2017, primarily due to increases in CO_2 emissions. From 2008, emissions decreased by 6 percent, primarily due to decreases in CH_4 emissions. National total dry gas production in the United States increased by 71 percent from 1990 to 2018, and by 12 percent from 2017 to 2018, and by 52 percent from 2008 to 2018. Of the overall greenhouse gas emissions (174.9 MMT CO_2 Eq.), 80 percent are CH_4 emissions (140.0 MMT CO_2 Eq.), 20 percent are CO_2 emissions (35.0 MMT), and less than 0.01 percent are N_2O emissions (0.01 MMT CO_2 Eq.).

Overall, natural gas systems emitted 140.0 MMT CO_2 Eq. (5,598 kt CH_4) of CH_4 in 2018, a 24 percent decrease compared to 1990 emissions, and less than 1 percent increase compared to 2017 emissions (see Table 3-57 and Table 3-58). There was a total of 35.0 MMT CO_2 Eq. (34,972 kt) of non-combustion CO_2 in 2018, an 9 percent increase compared to 1990 emissions, and a 15 percent increase compared to 2017 levels. The 2018 N_2O emissions were estimated to be 0.01 MMT CO_2 Eq. (0.03 kt N_2O), a 116 percent increase compared to 1990 emissions.

The 1990 to 2018 trend is not consistent across segments or gases. Overall, the 1990 to 2018 decrease in CH_4 emissions is due primarily to the decrease in emissions from the following segments: distribution (73 percent decrease), transmission and storage (41 percent decrease), processing (43 percent decrease), and exploration (72 percent decrease). Over the same time period, the production segment saw increased CH_4 emissions of 41 percent (with onshore production emissions increasing 30 percent, offshore production emissions decreasing 80 percent, and gathering and boosting [G&B] emissions increasing 91 percent). The 1990 to 2018 increase in CO_2 emissions is primarily due to increase in CO_2 emissions in the production segment, where emissions from flaring have increased over time.

Methane and 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, flaring, and leak 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. Emissions of N_2O from flaring activities are included in the Inventory, with most of the emissions occurring in the processing and production segments. Note, CO_2 emissions exclude all combustion emissions (e.g., engine combustion) except for flaring CO_2 emissions. All combustion CO_2 emissions (except for flaring) are accounted for in Section 3.1 – CO_2 from Fossil Fuel Combustion .

Each year, some estimates in the Inventory are recalculated with improved methods and/or data. These improvements are implemented consistently across the previous Inventory's time series (i.e., 1990 to 2017) to ensure that the trend is accurate. Recalculations in natural gas systems in this year's Inventory include:

- Updated methodology for G&B stations to use data from GHGRP, Zimmerle et al. 2019, and other sources.
- Updated methodology for offshore gas production to use data from BOEM, GHGRP, and other sources.
- Recalculations due to GHGRP submission revisions.

The Recalculations Discussion section below provides more details on the updated methods.

Below is a characterization of the five major segments of the natural gas system: exploration, production (including gathering and boosting), processing, transmission and storage, and distribution. Each of the segments is described and the different factors affecting CH_4, CO_2, and N_2O emissions are discussed.

Exploration. Exploration includes well drilling, testing, and completions. Emissions from exploration account for 1 percent of CH_4 emissions and 1 percent of CO_2 emissions from natural gas systems in 2018. Well completions account for approximately 97 percent of CH_4 emissions from the exploration segment in 2018, with the rest resulting from well testing and drilling. Flaring emissions account for most of the CO_2 emissions. Methane emissions from exploration decreased by 72 percent from 1990 to 2018, with the largest decreases coming from hydraulically fractured gas well completions without reduced emissions completions (RECs). Methane emissions decreased 10 percent from 2017 to 2018 due to decreases in emissions from hydraulically fractured well completions. Methane emissions were highest from 2006 to 2008. Carbon dioxide emissions from exploration increased by 1 percent from 1990 to 2018, and decreased 10 percent from 2017 to 2018 due to decreases in flaring. Carbon dioxide emissions were highest from 2006 to 2008. Nitrous oxide emissions increased 80 percent from 1990 to 2018, and increased 53 percent from 2017 to 2018.

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 from well-site equipment and activities such as pneumatic controllers, tanks and separators, and liquids unloading. Gathering and boosting emission sources 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). Boosting processes include compression, dehydration, and transport of gas to a processing facility or pipeline. Emissions from production (including gathering and boosting) account for 58 percent of CH_4 emissions and 27 percent of CO_2 emissions from natural gas systems in 2018. Emissions from gathering and boosting and pneumatic controllers in onshore production, account for most of the production segment CH_4 emissions in 2018. Within gathering and boosting, the largest sources are compressor exhaust slip, compressor venting and leaks, and pneumatic controllers. Flaring emissions account for most of the CO_2 emissions from production, with the highest emissions coming from flare stacks at gathering stations, miscellaneous onshore production flaring, and tank flaring. Methane emissions from production increased by 41 percent from 1990 to 2018, due primarily to increases in emissions from pneumatic controllers (due to an increase in the number of controllers, particularly in the number of intermittent bleed controllers) and increases in emissions from compressor exhaust slip in gathering and boosting. Methane emissions decreased 2 percent from 2017 to 2018 due to decreases in the number of high bleed and intermittent bleed controllers. Methane emissions were highest in 2008-2013. Carbon dioxide emissions from production increased approximately by a factor of 3 from 1990 to 2018 due to increases in emissions at flare stacks in gathering and boosting and miscellaneous onshore production flaring, and increased 47 percent from 2017 to 2018 due primarily to increases in emissions from flare stacks in gathering and boosting and flaring at tanks. Carbon dioxide emissions were highest in 2018. Nitrous oxide emissions increased 35 percent from 1990 to 2018 and increased 36 percent from 2017 to 2018. The increase in N_2O emissions from 1990 to 2018 and from 2017 to 2018 is primarily due to increase in emissions from flare stacks at gathering and boosting.

Processing. In the processing segment, 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. Methane emissions from compressors, including compressor seals, are the primary emission source from this stage. Most of the CO_2 emissions come from acid gas removal (AGR) units, which are designed to remove CO_2 from natural gas. Processing plants account for 9 percent of CH_4 emissions and 70 percent of CO_2 emissions from natural gas systems. Methane emissions from processing decreased by 43 percent from 1990 to 2018 as emissions from compressors (leaks and

venting) and equipment leaks decreased; and increased 6 percent from 2017 to 2018 due to increased emissions from gas engines and blowdowns/venting. Carbon dioxide emissions from processing decreased by 14 percent from 1990 to 2018, due to a decrease in AGR emissions, and increased 7 percent from 2017 to 2018 due to increased emissions from flaring. Nitrous oxide emissions increased 29 percent from 2017 to 2018.

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. Leak CH_4 emissions from these compressor stations and venting from pneumatic controllers account for most of the emissions from this stage. Uncombusted compressor 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). Leak and venting emissions from compressors are the primary contributors to CH_4 emissions from storage. Emissions from liquified natural gas (LNG) stations and terminals are also calculated under the transmission and storage segment. Methane emissions from the transmission and storage segment account for approximately 24 percent of emissions from natural gas systems, while CO_2 emissions from transmission and storage account for 1 percent of the CO_2 emissions from natural gas systems. CH_4 emissions from this source decreased by 41 percent from 1990 to 2018 due to reduced compressor station emissions (including emissions from compressors and leaks), and increased 5 percent from 2017 to 2018 due to increased emissions from transmission compressor exhaust and increased emissions from reciprocating transmission compressors. CO_2 emissions from transmission and storage have increased by a factor of 2.7 from 1990 to 2018, due to increased emissions from LNG export terminals, and decreased by less than 1 percent from 2017 to 2018. The quantity of LNG exported from the U.S. increased by a factor of 21 from 1990 to 2018, and by 53 percent from 2017 to 2018. LNG emissions are about 1 percent of CH_4 and 61 percent of CO_2 emissions from transmission and storage in year 2018. Nitrous oxide emissions from transmission and storage decreased by 24 percent from 1990 to 2018 and decreased 58 percent from 2017 to 2018.

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 1,305,781 miles of distribution mains in 2018, an increase of nearly 361,624 miles since 1990 (PHMSA 2019). Distribution system emissions, which account for 8 percent of CH_4 emissions from natural gas systems and less than 1 percent of CO_2 emissions, resulting mainly from leak 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 2018 were 73 percent lower than 1990 levels and less than 1 percent lower than 2017 emissions. Distribution system CO_2 emissions in 2018 were 73 percent lower than 1990 levels and less than 1 percent lower than 2017 emissions. Annual 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 five major stages of natural gas systems are shown in MMT CO_2 Eq. (Table 3-57) and kt (Table 3-58). Most emission estimates are calculated using a net emission approach. However, a few sources are still calculated with a potential emission approach. Reductions data are applied to those sources that use a potential emissions approach; in recent years 6.8 MMT CO_2 Eq. CH_4 are subtracted from production segment emissions and 6.7 MMT CO_2 Eq. CH_4 are subtracted from the transmission and storage segment to calculate net emissions. More disaggregated information on potential emissions, net emissions, and reductions data are available in Annex 3.6. See Methodology for Estimating CH_4 and CO_2 Emissions from Natural Gas Systems.

Table 3-57: CH_4 Emissions from Natural Gas Systems (MMT CO_2 Eq.)[a]

Stage	1990	2005	2014	2015	2016	2017	2018
Exploration[b]	**4.0**	**10.3**	**1.0**	**1.0**	**0.7**	**1.2**	**1.1**
Production	**57.2**	**76.9**	**84.6**	**83.7**	**81.8**	**82.3**	**80.9**
Onshore Production	34.9	51.4	49.2	46.9	45.1	45.5	45.3
Gathering and Boosting[c]	18.2	23.7	34.6	36.1	35.9	36.1	34.8

Offshore Production	4.1	1.8	0.8	0.6	0.8	0.7	0.8
Processing	**21.3**	**11.6**	**11.0**	**11.0**	**11.2**	**11.5**	**12.2**
Transmission and Storage	**57.2**	**36.1**	**32.3**	**34.1**	**30.1**	**32.3**	**33.9**
Distribution	**43.5**	**23.3**	**12.2**	**12.0**	**12.0**	**11.9**	**11.8**
Total	**183.3**	**158.1**	**141.1**	**141.9**	**135.8**	**139.3**	**140.0**

Note: Totals may not sum due to independent rounding.

[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.

[b] Exploration includes well drilling, testing, and completions.

[c] Gathering and boosting includes gathering and boosting station routine vented and leak sources, gathering pipeline leaks and blowdowns, and gathering and boosting station episodic events.

Table 3-58: CH_4 Emissions from Natural Gas Systems (kt)[a]

Stage	1990	2005	2014	2015	2016	2017	2018
Exploration[b]	**162**	**411**	**39**	**41**	**27**	**49**	**44**
Production	**2,289**	**3,076**	**3,385**	**3,347**	**3,273**	**3,291**	**3,238**
Onshore Production	1,396	2,057	1,968	1,877	1,805	1,820	1,814
Gathering and Boosting[c]	729	946	1,386	1,445	1,435	1,443	1,391
Offshore Production	165	73	31	24	33	28	33
Processing	**853**	**463**	**440**	**440**	**448**	**461**	**488**
Transmission and Storage	**2,228**	**1,442**	**1,292**	**1,365**	**1,205**	**1,294**	**1,355**
Distribution	**1,741**	**932**	**487**	**481**	**480**	**476**	**473**
Total	**7,332**	**6,324**	**5,643**	**5,674**	**5,433**	**5,570**	**5,598**

Note: Totals may not sum due to independent rounding.

[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.

[b] Exploration includes well drilling, testing, and completions.

[c] Gathering and boosting includes gathering and boosting station routine vented and leak sources, gathering pipeline leaks and blowdowns, and gathering and boosting station episodic events.

Table 3-59: Non-combustion CO_2 Emissions from Natural Gas Systems (MMT)

Stage	1990	2005	2014	2015	2016	2017	2018
Exploration	0.4	1.6	0.8	0.3	0.2	0.5	0.4
Production	3.2	4.5	7.5	7.7	7.4	6.5	9.6
Processing	28.3	18.9	21.1	21.1	21.9	22.9	24.5
Transmission and Storage	0.2	0.2	0.2	0.2	0.3	0.5	0.5
Distribution	0.1	+	+	+	+	+	+
Total	**32.2**	**25.3**	**29.6**	**29.3**	**29.9**	**30.4**	**35.0**

Note: Totals may not sum due to independent rounding.

+ Does not exceed 0.1 MMT CO_2 Eq.

Table 3-60: Non-combustion CO_2 Emissions from Natural Gas Systems (kt)

Stage	1990	2005	2014	2015	2016	2017	2018
Exploration	408	1,648	843	282	190	456	410
Production	3,197	4,548	7,464	7,740	7,450	6,505	9,591
Processing	28,338	18,893	21,075	21,075	21,908	22,896	24,465
Transmission and Storage	180	174	223	223	300	493	491
Distribution	51	27	14	14	14	14	14
Total	**32,174**	**25,291**	**29,620**	**29,334**	**29,862**	**30,365**	**34,972**

Note: Totals may not sum due to independent rounding.

Table 3-61: N_2O Emissions from Natural Gas Systems (metric tons CO_2 Eq.)

Stage	1990	2005	2014	2015	2016	2017	2018
Exploration	241	442	514	3,204	111	285	436
Production	4,295	5,696	8,987	9,809	8,871	4,282	5,808
Processing	NO	3,347	5,764	5,764	3,794	3,042	3,922
Transmission and Storage	256	307	341	343	361	459	195
Distribution	NO	NO	NO	NO	NO	NO	NO
Total	**4,792**	**9,791**	**15,606**	**19,120**	**13,136**	**8,068**	**10,361**

Note: Totals may not sum due to independent rounding.
NO (Not Occurring)

Table 3-62: N_2O Emissions from Natural Gas Systems (metric tons N_2O)

Stage	1990	2005	2014	2015	2016	2017	2018
Exploration	0.8	1.5	1.7	10.8	0.4	1.0	1.5
Production	14.4	19.1	30.2	32.9	29.8	14.4	19.5
Processing	NO	11.2	19.3	19.3	12.7	10.2	13.2
Transmission and Storage	0.9	1.0	1.1	1.2	1.2	1.5	0.7
Distribution	NO	NO	NO	NO	NO	NO	NO
Total	**16.1**	**32.9**	**52.4**	**64.2**	**44.1**	**27.1**	**34.8**

Note: Totals may not sum due to independent rounding.
NO (Not Occurring)

Methodology

See Annex 3.6 for the full time series of emissions data, activity data, and emission factors, and additional information on methods and data sources—for example, the specific years of reporting data from EPA's Greenhouse Gas Reporting Program (GHGRP) that are used to develop certain factors.

This section provides a general overview of the methodology for natural gas system emission estimates in the Inventory, which involves the calculation of CH_4, CO_2, and N_2O emissions for over 100 emissions sources (i.e., equipment types or processes), 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 most 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 emission reduction data to calculate net emissions.

Emission Factors. Key references for emission factors for CH_4 and CO_2 emissions from the U.S. natural gas industry include a 1996 study published by the Gas Research Institute (GRI) and EPA (GRI/EPA 1996), the EPA's GHGRP (EPA 2019), and others.

The GRI/EPA 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 GRI/EPA study was based on a combination of process engineering studies, collection of activity data, and measurements at representative natural gas facilities conducted in the early 1990s. Year-specific natural gas CH_4 compositions are calculated using U.S. Department of Energy's Energy Information Administration (EIA) annual gross production data for National Energy Modeling System (NEMS) oil and gas supply module regions in conjunction with data from the Gas Technology Institute (GTI, formerly GRI) Unconventional Natural Gas and Gas Composition Databases (GTI 2001). These year-specific CH_4 compositions are applied to emission factors, which therefore may vary from year to year due to slight changes in the CH_4 composition of natural gas for each NEMS region.

GHGRP Subpart W data were used to develop CH_4, CO_2, and N_2O emission factors for many sources in the Inventory. In the exploration and production segments, GHGRP data were used to develop emission factors used for all years of the time series for well testing, gas well completions and workovers with and without hydraulic

fracturing, pneumatic controllers and chemical injection pumps, condensate tanks, liquids unloading, miscellaneous flaring, gathering and boosting pipelines, and certain sources at gathering and boosting stations. In the processing segment, for recent years of the times series, GHGRP data were used to develop emission factors for leaks, compressors, flares, dehydrators, and blowdowns/venting. In the transmission and storage segment, GHGRP data were used to develop factors for all years of the time series for LNG stations and terminals and transmission pipeline blowdowns, and for pneumatic controllers for recent years of the times series.

Other data sources used for CH_4 emission factors include Zimmerle et al. (2015) for transmission and storage station leaks and compressors, Lamb et al. (2015) for recent years for distribution pipelines and meter/regulator stations, Zimmerle et al. (2019) for gathering and boosting stations, and Bureau of Ocean Energy Management (BOEM) reports.

For CO_2 emissions from sources in the exploration, production and processing segments that use emission factors not directly calculated from GHGRP data, data from the 1996 GRI/EPA study and a 2001 GTI publication were used to adapt the CH_4 emission factors into related CO_2 emission factors. For sources in the transmission and storage segment that use emission factors not directly calculated from GHGRP data, and for sources in the distribution segment, data from the 1996 GRI/EPA study and a 1993 GTI publication were used to adapt the CH_4 emission factors into non-combustion related CO_2 emission factors.

Flaring N_2O emissions were estimated for flaring sources using GHGRP data.

See Annex 3.6 for more detailed information on the methodology and data used to calculate CH_4, CO_2, and N_2O 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 EPA's GHGRP; Enverus DrillingInfo, Inc. (Enverus DrillingInfo 2019); BOEM; Federal Energy Regulatory Commission (FERC); EIA; the Natural Gas STAR Program annual data; Oil and Gas Journal; PHMSA; 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 2017 data were used as a proxy for 2018 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, net emissions are calculated directly by applying emission factors to activity data. Emission factors used in net emission approaches reflect technology-specific information, and take into account regulatory and voluntary reductions. However, for production and transmission and storage, 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 but are not reflected in "potential" emission factors, data are collected on both regulatory and voluntary reductions. Regulatory actions addressed using this method include EPA 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 for certain sources.

Through EPA's stakeholder process on oil and gas in the Inventory, EPA received initial stakeholder feedback on updates under consideration for the Inventory. Stakeholder feedback is noted below in Uncertainty and Time-Series Consistency, Recalculations Discussion, and Planned Improvements.

Uncertainty and Time-Series Consistency

EPA has conducted a quantitative uncertainty analysis using the IPCC Approach 2 methodology (Monte Carlo Simulation technique) to characterize the uncertainty for natural gas systems. For more information on the

approach, please see the memorandum *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2016: Natural Gas and Petroleum Systems Uncertainty Estimates (2018 Uncertainty Memo).*[83] EPA used Microsoft Excel's @RISK add-in tool to estimate the 95 percent confidence bound around CH_4 emissions from natural gas systems for the current Inventory, then applied the calculated bounds to both CH_4 and CO_2 emissions estimates. For the analysis, EPA focused on the 13 highest-emitting sources for the year 2018, which together emitted 83 percent of methane from natural gas systems in 2018, and extrapolated the estimated uncertainty for the remaining sources. The @RISK add-in provides for the specification of probability density functions (PDFs) 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." The uncertainty bounds reported below only reflect those uncertainties that EPA has been able to quantify and do not incorporate considerations such as modeling uncertainty, data representativeness, measurement errors, misreporting or misclassification. The understanding of the uncertainty of emission estimates for this category evolves and improves as the underlying methodologies and datasets improve.

The results presented below provide the 95 percent confidence bound within which actual emissions from this source category are likely to fall for the year 2018, using the IPCC methodology. The results of the Approach 2 uncertainty analysis are summarized in Table 3-63. Natural gas systems CH_4 emissions in 2018 were estimated to be between 118.2 and 159.6 MMT CO_2 Eq. at a 95 percent confidence level. Natural gas systems CO_2 emissions in 2018 were estimated to be between 29.5 and 39.9 MMT CO_2 Eq. at a 95 percent confidence level. Uncertainty bounds for other years of the time series have not been calculated, but uncertainty is expected to vary over the time series. For example, years where many emission sources are calculated with interpolated data would likely have higher uncertainty than years with predominantly year-specific data.

Table 3-63: Approach 2 Quantitative Uncertainty Estimates for CH_4 and Non-combustion CO_2 Emissions from Natural Gas Systems (MMT CO_2 Eq. and Percent)

Source	Gas	2018 Emission Estimate (MMT CO_2 Eq.)[b]	Uncertainty Range Relative to Emission Estimate[a] (MMT CO_2 Eq.)		Uncertainty Range Relative to Emission Estimate[a] (%)	
			Lower Bound[b]	Upper Bound[b]	Lower Bound[b]	Upper Bound[b]
Natural Gas Systems	CH_4	140.0	118.2	159.6	-15%	+14%
Natural Gas Systems[c]	CO_2	35.0	29.5	39.9	-15%	+14%

[a] Range of emission estimates estimated by applying the 95 percent confidence intervals obtained from the Monte Carlo Simulation analysis conducted for the year 2018 CH_4 emissions.

[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 3-57 and Table 3-58.

[c] An uncertainty analysis for the 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 CO_2 emissions.

GHGRP data available (starting in 2011) and other recent data sources have improved estimates of emissions from natural gas systems. To develop a consistent time series, 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 through 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 Recalculations Discussion below, with additional detail provided in supporting memos (relevant memos are cited in the Recalculations Discussion). For detailed documentation of methodologies, please see Annex 3.5.

[83] See < https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems>.

QA/QC and Verification Discussion

The natural gas systems 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.[84]

As in previous years, EPA conducted early engagement and communication with stakeholders on updates prior to public review. EPA held a stakeholder webinar in September of 2019 and a stakeholder workshop on greenhouse gas data for oil and gas in November of 2019. EPA released memos detailing updates under consideration and requesting stakeholder feedback.

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 of 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 the Emissions Database for Global Atmospheric Research, or "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° x 0.1° spatial resolution, monthly temporal resolution, and detailed scale-dependent error characterization.[85] 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.[86]

Recalculations Discussion

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 September and November 2019, EPA released draft memoranda that discussed changes under consideration, and requested stakeholder feedback on those changes. EPA then created an updated version of the memoranda to document the methodology implemented in the current Inventory.[87] Memoranda cited in the Recalculations Discussion below are: *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2018: Updates for Natural Gas*

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

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

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

[87] Stakeholder materials including draft and final memoranda for the current (i.e., 1990-2018) Inventory are available at <https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems>.

Gathering & Boosting Station Emissions (*G&B Station* memo) and *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2018: Updates for Offshore Production Emissions* (*Offshore Production* memo).

EPA thoroughly evaluated relevant information available and made several updates to the Inventory, including: using GHGRP, BOEM, and other data to calculate emissions from offshore production; and using GHGRP and Zimmerle et al. 2019 study data to calculate gathering and boosting station emissions. In addition, certain sources did not undergo methodological updates, but CH_4 and/or CO_2 emissions changed by greater than 0.05 MMT CO_2 Eq., comparing the previous estimate for 2017 to the current (recalculated) estimate for 2017 (the emissions changes were mostly due to GHGRP data submission revisions). These sources are discussed below and include: hydraulically fractured (HF) gas well completions; production segment pneumatic controllers; liquids unloading; production segment storage tanks; HF and non-HF gas well workovers; and acid gas removal (AGR) vents, flares, reciprocating compressors, and blowdowns at gas processing plants.

The combined impact of revisions to 2017 natural gas sector CH_4 emissions, compared to the previous Inventory, is a decrease from 165.6 to 139.3 MMT CO_2 Eq. (26.3 MMT CO_2 Eq., or 16 percent). The recalculations resulted in an average decrease in CH_4 emission estimates across the 1990 through 2017 time series, compared to the previous Inventory, of 14.2 MMT CO_2 Eq., or 8 percent.

The combined impact of revisions to 2017 natural gas sector CO_2 emissions, compared to the previous Inventory, is an increase from 26.3 MMT to 30.4 MMT, or 15 percent. The recalculations resulted in an average increase in emission estimates across the 1990 through 2017 time series, compared to the previous Inventory, of 2.9 MMT CO_2 Eq., or 12 percent.

The combined impact of revisions to 2017 natural gas sector N_2O emissions, compared to the previous Inventory, is an increase from 4.7 kt CO_2 Eq. to 8.1 kt CO_2 Eq., or 70 percent. The recalculations resulted in an average increase in emission estimates across the 1990 through 2017 time series, compared to the previous Inventory, of a factor of 2.5.

In Table 3-64 and Table 3-65 below are categories in Natural Gas Systems with recalculations resulting in a change of greater than 0.05 MMT CO_2 Eq., comparing the previous estimate for 2017 to the current (recalculated) estimate for 2017. For more information, please see the Recalculations Discussion below.

Table 3-64: Recalculations of CO_2 in Natural Gas Systems (MMT CO_2)

Stage and Emission Source	*Previous Estimate Year 2017, 2019 Inventory*	Current Estimate Year 2017, 2020 Inventory	Current Estimate Year 2018, 2020 Inventory
Exploration	***0.5***	**0.5**	**0.4**
Production	***2.8***	**6.5**	**9.6**
Gathering Stations	*0.2*	4.3	7.0
Offshore Gas Production	*0.4*	+	+
Tanks	*0.6*	0.5	0.8
Processing	***22.5***	**22.9**	**24.5**
AGR Vents	*16.7*	17.2	17.5
Transmission and Storage	***0.5***	**0.5**	**0.5**
Distribution	***+***	+	+
Total	***26.3***	**30.4**	**35.0**

+ Does not exceed 0.05 MMT CO_2.

Table 3-65: Recalculations of CH_4 in Natural Gas Systems (MMT CO_2 Eq.)

Stage and Emission Source	*Previous Estimate Year 2017, 2019 Inventory*	Current Estimate Year 2017, 2020 Inventory	Current Estimate Year 2018, 2020 Inventory
Exploration	***1.2***	**1.2**	**1.1**
Production	***108.4***	**82.3**	**80.9**

G&B Stations	55.5	32.0	31.4
Offshore Gas Production	*3.8*	0.7	0.8
Non-HF Workovers	*+*	0.1	+
Pneumatic Controllers	*26.4*	26.6	25.4
Liquids Unloading	*2.9*	3.2	4.4
HF Workovers	*0.8*	0.8	0.6
Processing	***11.7***	**11.5**	**12.2**
Reciprocating Compressors	*1.7*	1.6	1.6
Flares	*0.5*	0.6	0.7
Blowdowns/Venting	*0.9*	0.7	1.1
Transmission and Storage	***32.4***	**32.3**	**33.9**
Distribution	***11.9***	**11.9**	**11.8**
Total	***165.6***	**139.3**	**140.0**

+ Does not exceed 0.05 MMT CO_2 Eq.

Exploration

There were no methodological updates to the exploration segment, but there were recalculations due to updated data (e.g., GHGRP data for REC HF Completions with venting) that resulted in an average decrease in calculated emissions over the time series from this segment of 0.3 MMT CO_2 Eq. CH_4 (or 4 percent) and less than 0.05 MMT CO_2 (or 5 percent).

Production

Gathering and Boosting (G&B) Stations (Methodological Update)

EPA updated the G&B station methodology to use data from a Zimmerle et al. 2019 study. Zimmerle et al. conducted CH_4 measurements at G&B stations, calculated CH_4 EFs for certain equipment (compressors, tanks, dehydrators, acid gas removal units, separators, and yard piping), and developed an approach to estimate national activity data for G&B stations. EPA applied data from Zimmerle et al. and incorporated Subpart W data (for both CH_4 and CO_2) across the time series for the final methodology implemented in the Inventory. EPA did not retain data from the previous methodology. EPA also applied the national average ratio of compressors per station and the national-level scaling factor, both based on year 2017 data, from the Zimmerle et al. study. The G&B emissions accounted for in the Inventory largely align with the G&B activities reported under Subpart W, because Subpart W activity data were used to determine the national-level scaling factor. The *G&B Station* Memo provides details on the methodology implemented into the final Inventory.

G&B station CH_4 emission estimates decreased by an average of 36 percent in the current Inventory for the 1990 to 2017 time series, compared to the previous Inventory. The decrease in the CH_4 emission estimate is due to differences in the data between the current Inventory and previous Inventory. Calculated G&B station CH_4 emission estimates decreased by an average of 36 percent in the current Inventory for each year in the 1990 to 2017 time series, compared to the previous Inventory. The decrease in the CH_4 emission estimate is due to differences in the input data between the current Inventory and the prior Inventory. The prior Inventory used data from a Marchese et al. 2015 study to calculate CH_4 emissions.[88]

Data were previously unavailable to quantify the largest sources of CO_2 from G&B stations. By incorporating recent Subpart W data on CO_2 from flaring and acid gas removal units (previously not included in the Inventory), the estimate of G&B station CO_2 emission increased by a factor of 22 (from an average of 0.2 MMT CO_2 to an average of 3.5 MMT CO_2) in the current Inventory for the 1990 to 2017 time series, compared to the previous Inventory.

[88] Marchese, A. J. et al., Methane Emissions from United States Natural Gas Gathering and Processing. Environmental Science & Technology, 49, 10718-10727. 2015.

Feedback from three stakeholder comment letters supported the update to gathering and boosting. Of these stakeholder comments, one also specifically supported the use of the Zimmerle et al. approach to developing the national-level scaling factor to account for GHGRP non-reporters, and another suggested that the scaling factor and national average ratio of compressors per station be updated annually in future Inventories if data are available to do so.

One stakeholder comment letter did not support the update. The comment letter noted discrepancies found between site-level and component-level emissions data in recent studies (citing work primarily focusing on the onshore production segment. For comparison with an alternative national-level gathering and boosting estimate, the letter references an estimate in Alvarez et al., which relied primarily on the Marchese et al. study (previous Inventory data source), and the application of an adjustment factor of 10 percent. The comment letter recommended retaining the previous (Marchese et al.) data source. In their paper, Zimmerle et al. discussed differences between the Zimmerle et al. study (current data source) and the Marchese et al. Study (previous data source). The differences noted in Zimmerle et al. are: (1) the Zimmerle et al. study uses an updated and likely more representative mix of stations in terms of throughput and complexity, (2) the Zimmerle et al. study accessed component level activity and emissions data from the GHGRP, which were not available at the time of the Marchese et al. study, and which represented data from a large set of operators for the entire U.S., (3) the two studies utilized different measurement methods, and (4) there may have been operational improvements to G&B stations and/or construction of new lower-emitting stations during the intervening years between studies due to increased attention to CH_4 emissions across the natural gas value chain.

The stakeholder comment letter that did not support the update to gathering and boosting also expressed concern about the potential omission of "super-emitters." The Zimmerle et al. study detected a number of large emitters. For example, the study noted that "For most leaker factors, 50% or more of emissions are due to the largest 5% of emitters." The set of emission factors developed in the Zimmerle et al. study which were used to calculate emissions in the GHG Inventory include estimates for all emissions detected in the field campaign, including estimates for large emitters, and the study notes that these "Large emitter emissions have substantial impact on major equipment emission factors, adding 70% - 83% to the impacted major equipment factors."

The stakeholder comment letter that did not support the update to gathering and boosting also sought additional information justifying the use of the Zimmerle et al. (measurements conducted in 2017) and GHGRP (data available starting in 2016) data across the time series as opposed to using data from Marchese et al. (measurements from 2013 and 2014) for previous years. EPA considered this approach but did not implement it in the Inventory due to incongruencies between the studies noted in the previous paragraph. If the Marchese et al. study in emissions and activity data were used for early years of the time series (e.g., 1990-2014) and the Zimmerle et al. and GHGRP data were used in more recent years (e.g. 2016-2017), there would be a large decrease in emissions over a short period of time due to this transition. Some fraction of the decrease would likely be attributable to improvements in technologies and industry practices. However, as noted above there are other differences between the studies such as study representativeness and the difference between the two is likely not entirely due to changes in technologies (or any other single factor). For this reason, EPA did not implement an approach that uses data from both of the studies in different parts of the time series.

Table 3-66: Gathering Stations National CH_4 Emissions (metric tons CH_4)

Source	1990	2005	2014	2015	2016	2017	2018
Compressors	126,757	161,098	243,532	255,491	253,209	271,238	278,874
Tanks	135,802	172,593	260,910	273,723	271,278	205,261	180,945
Station Blowdowns	20,560	26,130	39,501	41,441	41,071	63,823	62,020
Dehydrator Vents - Large units	29,975	38,096	57,590	60,419	59,879	51,668	48,401
Dehydrator Vents - Small units	306	389	588	617	612	708	575
High-bleed Pneumatic Devices	16,698	21,222	32,081	33,656	33,356	32,654	23,666
Intermittent Bleed Pneumatic Devices	79,110	100,543	151,991	159,455	158,031	173,628	156,662

Low-Bleed Pneumatic Devices	2,835	3,603	5,446	5,714	5,663	6,344	5,722
Flare Stacks	5,300	6,736	10,183	10,683	10,588	9,394	13,935
AGRU	47	60	90	94	94	91	88
Pneumatic Pumps	15,844	20,137	30,441	31,936	31,651	23,391	24,878
Gas Engines	169,766	215,760	326,164	342,182	339,126	363,534	373,753
Dehydrator Leaks	851	1,081	1,634	1,715	1,699	1,852	1,882
Yard Piping	37,206	47,286	71,482	74,992	74,323	76,709	85,115
Separators	559	710	1,073	1,126	1,116	1,152	1,278
Desiccant Dehydrators	8	11	16	17	17	38	4
Total Emissions	**641,624**	**815,454**	**1,232,724**	**1,293,262**	**1,281,711**	**1,281,484**	**1,257,799**
Previous Estimate	*1,051,775*	*1,217,024*	*2,063,775*	*2,163,417*	*2,143,324*	*2,218,773*	*NA*

NA (Not Applicable)

Table 3-67: Gathering Stations National CO_2 Emissions (metric tons CO_2)

Source	1990	2005	2014	2015	2016	2017	2018
Compressors	15,277	19,416	29,351	30,793	30,517	32,690	33,611
Tanks	420,699	534,676	808,271	847,965	840,391	633,931	1,294,821
Station Blowdowns	1,587	2,017	3,049	3,199	3,170	4,923	9,572
Dehydrator Vents - Large units	369,890	470,102	710,654	745,554	738,894	763,329	796,516
Dehydrator Vents - Small units	332	422	638	669	663	1,266	4,860
High-bleed Pneumatic Devices	1,143	1,452	2,195	2,303	2,282	2,120	1,714
Intermittent Bleed Pneumatic Devices	5,240	6,659	10,067	10,561	10,467	13,172	13,066
Low-Bleed Pneumatic Devices	213	271	409	429	425	399	410
Flare Stacks	1,354,751	1,721,783	2,602,824	2,730,646	2,706,255	2,300,171	4,205,760
AGRU	246,880	313,765	474,319	497,612	493,167	527,835	643,969
Pneumatic Pumps	963	1,224	1,850	1,941	1,924	1,683	1,679
Dehydrator Leaks	103	130	197	207	205	223	227
Yard Piping	4,484	5,699	8,615	9,038	8,958	9,245	10,258
Separators	67	86	129	136	135	139	154
Desiccant Dehydrators	+	+	+	+	+	+	+
Total Emissions	**2,421,629**	**3,077,701**	**4,652,569**	**4,881,053**	**4,837,454**	**4,291,126**	**7,016,615**
Previous Estimate	*93,791*	*143,218*	*221,279*	*233,320*	*232,491*	*239,459*	*NA*

NA (Not Applicable)
+ Less than 0.5 metric tons

Offshore Gas Production (Methodological Update)

EPA updated the offshore production methodology to estimate emissions for all offshore producing regions and to use activity data sources that provide a full time series of data. The previous Inventory only estimated emissions for offshore facilities in federal waters of the Gulf of Mexico (GOM); these facilities are under Bureau of Ocean Energy Management (BOEM) jurisdiction and BOEM estimates their greenhouse gas emissions triennially via the Gulfwide Emissions Inventory (GEI). The previous Inventory also relied on activity data sources that were no longer updated, and surrogate activity data from 2008 and 2010 had been used to estimate emissions in more recent years. The updated Inventory methodology now includes emissions estimates for offshore facilities in federal and state waters of the GOM and offshore facilities off the coast of Alaska.

The updated Inventory methodology for each region is presented here. EPA calculated vent and leak EFs for offshore facilities in GOM federal waters for major complexes and minor complexes using BOEM GEI emissions data from the 2005, 2008, 2011, 2014, and 2017 GEIs. Vent and leak EFs were calculated for 11 emission sources (cold vents, fugitives, pneumatic pumps, losses from flashing, pneumatic controllers, combustion, glycol

dehydrators, storage tanks, mud degassing, minor surrogates, and amine gas sweetening units). These EFs were paired with active offshore complex counts over the time series. EPA calculated GOM federal waters flaring emissions using flaring volumes reported in Oil and Gas Operations Reports (OGOR), Part B (OGOR-B). OGOR-B flaring volumes are available over the time series but assumptions were necessary to assign the volumes to offshore gas production versus offshore oil production for 1990 to 2010. The previous Inventory allocated all GOM federal waters flaring emissions to offshore gas production facilities. EPA calculated production based EFs for offshore facilities in GOM state waters using the resulting GOM federal waters emissions and gas production in each year. EPA also calculated production based EFs for offshore facilities in the Alaska region, and the EFs for these regions were derived from GHGRP data. EPA multiplied the production based EFs by the region-specific offshore production (i.e., GOM state waters production, and Alaska production) in a given year. The *Offshore Production* memo provides details for the methodology update under consideration and that was implemented in the Inventory.

Due to this recalculation, annual offshore gas production CH_4 emission estimates decreased in the current Inventory for 1990 to 2017 by an average of 14 percent, compared to the previous Inventory. The impacts varied across the time series with estimates in earlier years of the time series increasing (e.g., by an average of 19 percent from 1990 to 2002) and estimates in more recent years of the time series decreasing (e.g., by an average of 73 percent from 2010 to 2017). The increase in offshore gas production CH_4 emission estimates from 1990 to 2002 is due to the inclusion of emissions from facilities located in GOM state waters and the Alaska region. Examining the same 1990 through 2002 period, there is not a significant difference between offshore gas production CH_4 emission estimates in GOM federal waters between the current Inventory and previous Inventory, with an average increase of only 4 percent.

The noticeable decrease in offshore gas production CH_4 emission estimates over the 2010 to 2017 time period is due to a decrease in GOM federal waters emission estimates. The main factor that leads to a decrease in the estimate of offshore gas production CH_4 emissions for GOM federal waters facilities is the use of updated activity data. Activity data in the previous Inventory were last available for 2010, and the 2010 counts are applied as surrogate to all following years. The updated methodology for the current Inventory uses a continuously updated BOEM data source, and it shows a noticeable decrease in offshore facilities starting in 2008 that is not captured in the previous Inventory's data.

For comparison, total offshore production (for oil and gas combined) CH_4 emissions for facilities in GOM federal waters are provided here for years 2011, 2014, and 2017 from the GEI, previous Inventory, and current Inventory. For offshore facilities in GOM federal waters in year 2011, GEI CH_4 emissions equaled 246 kt, previous Inventory CH_4 emissions equaled 338 kt, and current Inventory CH_4 emissions equal 278 kt. For offshore facilities in GOM federal waters in year 2014, GEI CH_4 emissions equaled 205 kt, previous Inventory CH_4 emissions equaled 338 kt, and current Inventory CH_4 emissions equal 225 kt. For offshore facilities in GOM federal waters in year 2017, GEI CH_4 emissions equaled 170 kt, previous Inventory CH_4 emissions equaled 338 kt, and current Inventory CH_4 emissions equal 206 kt.

Annual offshore gas production CO_2 emission estimates decreased in the current Inventory for 1990 to 2017 by an average of 71 percent, compared to the previous Inventory. This change is largely because all GOM federal waters flaring emissions in the previous Inventory were allocated to offshore gas production, whereas the current Inventory estimates GOM federal waters flaring emissions for both offshore gas and oil production, and a significant portion of the CO_2 is from offshore oil production.

EPA received feedback on this update through its September 2019 memo and through the public review draft of the Inventory. Two stakeholders supported the update to activity data. A stakeholder suggested clarifications on the calculation of emission factors, and noted upcoming data that may be used to assess offshore emission factors. A stakeholder suggested clarification on the development of activity counts and supported considering a different approach which would use source-specific emission factors. As noted above, the emissions estimates were calculated using complex-level factors for offshore operations in GOM federal waters, and using production-based emission factors for offshore operations in state waters. An estimate of emissions source-level emissions was developed using the fraction of emissions in each category in the GOM federal waters data set, applied to GOM federal and state water total emission estimates, and using the fraction of emissions in each category in GHGRP for

Alaska offshore production, and applied to the total estimates for Alaska offshore production. The emission source-level estimates are available in the annex. The stakeholder noted that the use of emission factors calculated from data from the from the GHGRP reporting population (those emitting over the GHGRP threshold), applied to all Alaska offshore production could skew regional emission estimates. The stakeholder also supported the use of GEI data as opposed to OGOR-B data to calculate emissions from flaring. The emissions estimates were calculated using OGOR-B. GEI data is currently available for the years 2005, 2008, 2011, 2014, and 2017. The OGOR-B dataset can be used to calculate flaring emissions for the full 1990 to 2018 time series.

The recalculation results in a change in the trend, in methane in particular where the 1990 to 2017 trend in this Inventory is a decrease of 83 percent, versus an increase of 7 percent in the previous Inventory. The stakeholder provided several factors supporting this decreasing trend: more stringent limitations imposed by BSEE (Bureau of Safety and Environmental Enforcement) related to venting and flaring, increased utilization of VRU equipment, and replacement of older platforms with newer ones that include state of the art technology.

Table 3-68: Offshore Gas Production National Emissions (metric tons CH_4)

Source	1990	2005	2014	2015	2016	2017	2018
GOM Federal Waters	153,457	60,823	21,847	17,890	23,752	19,563	20,151
GOM State Waters	9,296	10,790	9,110	5,836	8,241	7,995	12,373
Alaska State Waters	1,892	1,498	453	329	591	501	618
Total Emissions	**164,645**	**73,111**	**31,410**	**24,055**	**32,585**	**28,060**	**33,141**
Previous Estimate	*140,949*	*173,459*	*150,565*	*150,565*	*150,565*	*150,565*	*NA*

NA (Not Applicable)

Table 3-69: Offshore Gas Production National Emissions (metric tons CO_2)

Source	1990	2005	2014	2015	2016	2017	2018
GOM Federal Waters	47,315	36,319	50,740	36,180	30,086	24,564	24,233
GOM State Waters	2,866	6,443	21,159	11,802	10,439	10,039	14,880
Alaska State Waters	19,825	15,695	4,745	3,448	2,563	3,483	1,877
Total Emissions	**70,006**	**58,457**	**76,644**	**51,430**	**43,088**	**38,085**	**40,989**
Previous Estimate	*232,959*	*183,731*	*367,861*	*370,479*	*371,788*	*372,116*	*NA*

NA (Not Applicable)

Pneumatic Controllers (Recalculation with Updated Data)

Pneumatic controller CH_4 emission estimates increased in the current Inventory by an average of 0.3 percent across the time series, compared to the previous Inventory due to GHGRP submission revisions and Enverus DrillingInfo data revisions.

Table 3-70: Production Segment Pneumatic Controller National Emissions (metric tons CH_4)

Source	1990	2005	2014	2015	2016	2017	2018
Low Bleed	NO	23,168	32,486	31,784	31,790	34,639	33,867
High Bleed	296,948	463,604	130,339	101,509	104,353	108,294	87,372
Intermittent Bleed	193,647	536,998	931,781	939,438	900,993	919,154	895,118
Total Emissions	**490,594**	**1,023,770**	**1,094,606**	**1,072,732**	**1,037,136**	**1,062,086**	**1,016,357**
Previous Estimate	*492,254*	*1,016,763*	*1,089,339*	*1,075,601*	*1,064,069*	*1,057,303*	*NA*

NO (Not Occurring)
NA (Not Applicable)

Liquids Unloading (Recalculation with Updated Data)

Liquids unloading CH_4 emission estimates increased for 2017 by 11 percent in the current Inventory, compared to the previous Inventory. Compared to the previous Inventory, on average across the time series, liquids unloading CH_4 emission estimates increased by less than 0.1 percent. These changes were due to GHGRP submission revisions.

Table 3-71: Liquids Unloading National Emissions (metric tons CH_4)

Source	1990	2005	2014	2015	2016	2017	2018
Unloading with Plunger Lifts	NO	125,582	80,402	62,836	59,787	58,617	78,069
Unloading without Plunger Lifts	371,391	247,032	129,520	97,225	67,876	71,173	99,229
Total Emissions	**371,391**	**372,614**	**209,921**	**160,061**	**127,663**	**129,790**	**177,298**
Previous Estimated Emissions	*372,325*	*373,442*	*210,784*	*160,706*	*130,778*	*117,379*	*NA*

NO (Not Occurring)
NA (Not Applicable)

Tanks (Recalculation with Updated Data)

Production tank CO_2 emission estimates decreased for 2017 by 10 percent in the current Inventory, compared to the previous Inventory. Compared to the previous Inventory, on average across the time series, tank CO_2 emission estimates decreased by 1 percent. These changes were due to GHGRP submission revisions.

Table 3-72: Production Segment Storage Tanks National Emissions (metric tons CO_2)

Source	1990	2005	2014	2015	2016	2017	2018
Large Tanks w/Flares	287,644	363,030	1,028,597	1,039,129	1,080,439	500,450	783,932
Large Tanks w/VRU	NO	760	2,782	2,811	2,434	44	58
Large Tanks w/o Control	164,501	88,897	153,447	155,018	902	219	7,235
Small Tanks w/Flares	NO	7,839	28,710	29,004	28,894	20,816	44,530
Small Tanks w/o Flares	5,638	4,300	9,850	9,950	12,388	4,090	8,943
Malfunctioning Separator Dump Valves	6	6	15	15	11	468	224
Total Emissions	**457,788**	**464,831**	**1,223,400**	**1,235,927**	**1,125,067**	**526,086**	**844,923**
Previous Estimate	*459,592*	*466,429*	*1,227,366*	*1,239,933*	*1,128,990*	*585,339*	*NA*

NO (Not Occurring)
NA (Not Applicable)

HF Gas Well Workovers (Recalculation with Updated Data)

Recalculations of HF gas well workover CH_4 emissions resulted in an average decrease of 4 percent across the 1990 to 2017 time series when comparing the current Inventory to the previous Inventory. These changes were due to GHGRP submission revisions.

Table 3-73: HF Gas Well Workovers National Emissions (metric tons CH_4)

Source	1990	2005	2014	2015	2016	2017	2018
HF Workovers - Non-REC with Venting	25,774	60,903	24,642	1,752	7,530	10,263	2,393
HF Workovers - Non-REC with Flaring	365	953	460	80	72	509	799
HF Workovers - REC with Venting	NO	576	569	8,685	6,312	17,005	21,181
HF Workovers - REC with Flaring	NO	4	25	1,658	1,240	3,708	50
Total Emissions	**26,139**	**62,437**	**25,695**	**12,175**	**15,155**	**31,485**	**24,422**
Previous Estimate	*26,188*	*67,717*	*26,608*	*13,161*	*15,551*	*33,711*	*NA*

NO (Not Occurring)
NA (Not Applicable)

Non-HF Gas Well Workovers (Recalculation with Updated Data)

Recalculations of non-HF gas well workover emissions resulted in a 484 percent increase in 2017 CH_4 estimates and an average increase of 4 percent across the 1990 to 2016 time series when comparing the current Inventory to the previous Inventory. The large increase for HF gas well workover emissions in 2017 results from GHGRP submission revisions.

Table 3-74: Non-HF Gas Well Workovers National Emissions (metric tons CH_4)

Source	1990	2005	2014	2015	2016	2017	2018
Non-HF Workovers - vented	484	667	443	532	539	3,484	342
Non-HF Workovers - flared	0	21	2	25	1	0	0
Total Emissions	**484**	**688**	**444**	**557**	**540**	**3,484**	**343**
Previous Estimate	*486*	*634*	*427*	*537*	*523*	*597*	*NA*

NA (Not Applicable)

Well Counts (Recalculation with Updated Data)

For total national well counts, EPA has used a more recent version of the Enverus DrillingInfo data set (Enverus DrillingInfo 2019) to update well counts data in the Inventory. While this is not a significant recalculation (increases are less than 1 percent across the time series), is the well count dataset is a key input to the Inventory, and results are highlighted here.

Table 3-75: Producing Gas Well Count Data

Activity	1990	2005	2014	2015	2016	2017	2018
Number of Gas Wells	193,232	346,484	422,701	419,692	419,346	412,601	405,026
Previous Estimate	*193,718*	*346,862*	*424,308*	*420,418*	*419,005*	*411,450*	*NA*

NA (Not Applicable)

In December 2019, EIA released an updated time series of national oil and gas well counts (covering 2000 through 2018). EIA estimates 982,371 total producing wells for year 2018. EPA's total well count for this year is 969,212. EPA's well counts in recent time series years are generally 1 percent lower than EIA's. EIA's well counts include side tracks, completions, and recompletions, and therefore are expected to be higher than EPA's which include only producing wells. EPA and EIA use a different threshold for distinguishing between oil versus gas (EIA uses 6 mcf/bbl, while EPA uses 100 mcf/bbl), which results in EIA having a lower fraction of oil wells and a higher fraction of gas wells than EPA.

Processing

Acid Gas Removal (Recalculation with Updated Data)

Acid gas removal unit (AGR) CO_2 emission estimates for 2016 and 2017 increased on average by 2 percent, comparing the current Inventory to the previous Inventory, due to GHGRP submission revisions, where a higher emission factor was calculated from the GHGRP data. The emission estimates were essentially unchanged across the 1990 to 2015 time series, comparing the current Inventory to the previous Inventory, with an average increase of 0.1 percent.

Table 3-76: AGR National CO_2 Emissions (kt CO_2)

Source	1990	2005	2014	2015	2016	2017	2018
Acid Gas Removal	28,282	15,339	14,979	14,979	16,679	17,182	17,451
Previous Estimate	*28,282*	*15,320*	14,946	14,946	16,481	16,728	*NA*

NA (Not Applicable)

Flares (Recalculation with Updated Data)

Processing segment flare CH_4 emission estimates decreased by 4 percent across the 2011 to 2017 time series in the current Inventory. Prior to 2011, flare-specific CH_4 emissions were not estimated. Instead, plant-wide emissions were calculated for years prior to 2011. Processing segment flare CH_4 emission estimates increased by approximately 15 percent for 2017 in the current Inventory, compared to the previous Inventory. This increase in

CH_4 emission estimates for 2017 is due to GHGRP submission revisions, where a higher emission factor was calculated from the GHGRP data.

Table 3-77: Processing Segment Flares National Emissions (metric tons CH_4)

Source	1990	2005	2014	2015	2016	2017	2018
Flares	NO	NE	19,509	19,509	19,988	24,277	26,146
Previous Estimate	*NO*	*NE*	*21,171*	*21,171*	*21,049*	*21,049*	*NA*

NO (Not Occurring)
NA (Not Applicable)
NE (Not estimated)

Reciprocating Compressors (Recalculation with Updated Data)

Reciprocating compressor CH_4 emission estimates decreased by 1 percent on average for 2011 to 2017 in the current Inventory and decreased by 5 percent for 2017 in the current Inventory, compared to the previous Inventory. This decrease in the CH_4 emission estimate for 2017 is due to GHGRP submission revisions, where a lower EF (mt CH_4/reciprocating compressor) was calculated from the GHGRP data.

Table 3-78: Processing Segment Reciprocating Compressors National Emissions (metric tons CH_4)

Source	1990	2005	2014	2015	2016	2017	2018
Reciprocating Compressors	324,939	NA	67,982	67,982	63,682	64,955	62,574
Previous Estimate	*324,939*	*NA*	*68,408*	*68,408*	*63,351*	*68,178*	*NA*

NA (Not Applicable)

Blowdowns/Venting (Recalculation with Updated Data)

Blowdowns and venting CH_4 emission estimates decreased by 2 percent across the 1990 to 2017 time series in the current Inventory and decreased by 20 percent for 2016 and 2017 in the current Inventory, compared to the previous Inventory. This decrease in CH_4 emissions for 2016 and 2017 is due to GHGRP submission revisions, where a lower emission factor (CH_4 from blowdowns/venting per plant) was calculated from the GHGRP data.

Table 3-79: Processing Segment Blowdowns/Venting National Emissions (metric tons CH_4)

Source	1990	2005	2014	2015	2016	2017	2018
Blowdowns/Venting	59,507	34,234	34,890	34,890	28,447	29,061	45,499
Previous Estimate	*59,507*	*34,264*	*34,943*	*34,943*	*36,428*	*36,266*	*NA*

NA (Not Applicable)

Transmission and Storage

There were no methodological updates to the transmission and storage segment, but there were recalculations due to updated data that resulted in an average increase in calculated emissions over the time series from this segment of 0.04 MMT CO_2 Eq. CH_4 (or 0.7 percent) and less than 0.04 MMT CO_2 (or 18 percent).

Distribution

There were no methodological updates to the distribution segment, and recalculations due to updated data resulted in average increases in calculated CH_4 and CO_2 emissions over the time series of 0.01 percent.

Planned Improvements

EPA seeks stakeholder feedback on the improvements noted below for future Inventories.

Gathering and Boosting Stations

EPA updated the G&B station methodology for the Inventory, incorporating the Zimmerle et al. 2019 study and Subpart W data. Comments on the public review draft of the Inventory suggested continuing to confirm and update the scaling factor applied to calculate national emissions. EPA plans to periodically reassess this factor. See the *G&B Station* memo for details on the updates under consideration and specific requests for stakeholder feedback.

Offshore Production

EPA updated the offshore production methodology for the Inventory, incorporating data from BOEM and GHGRP. Detailed information and considerations for various approaches considered for the methodology update were provided in a memorandum and discussed at a stakeholder workshop and webinar. Through the stakeholder process and the public review period, stakeholders provided feedback on additional approaches or data sets that could be used. In future inventories, EPA will consider alternate approaches or data sources, such as additional use of BOEM data or data from upcoming studies. Stakeholders identified upcoming studies of offshore oil and gas platform emissions that will include evaluation of different inventory estimates and methods.

Upcoming Data, and Additional Data that Could Inform the Inventory

EPA will assess new data received by the EPA Methane Challenge Program on an ongoing basis, which may be used to validate 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 emission estimates, which could lead to improved understanding of unassigned high emitters (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.
- Activity data and emissions data for production facilities that do not report to GHGRP.
- Natural gas leaks at point of use estimates.
- Anomalous leak events, such as a 2018 well blowout in Ohio.

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

3.8 Abandoned Oil and Gas Wells (CRF Source Categories 1B2a and 1B2b)

The term "abandoned wells" encompasses various types of wells:

- Wells with no recent production, and not plugged. Common terms (such as those used in state databases) might include: inactive, temporarily abandoned, shut-in, dormant, and idle.
- Wells with no recent production and no responsible operator. Common terms might include: orphaned, deserted, long-term idle, and abandoned.
- Wells that have been plugged to prevent migration of gas or fluids.

The U.S. population of abandoned wells is around 3.2 million (with around 2.6 million abandoned oil wells and 0.6 million abandoned gas wells). Abandoned wells emit both CH_4 and CO_2. Wells that are plugged have much lower

average emissions than wells that are unplugged (less than 1 kg CH_4 per well per year, versus over 100 kg CH_4 per well per year). Around a third of the abandoned well population in the United States is plugged. This fraction has increased over the time series (from around 19 percent in 1990) as more wells fall under regulations and programs requiring or promoting plugging of abandoned wells.

Abandoned oil wells. Abandoned oil wells emitted 227 kt CH_4 and 5 kt CO_2 in 2018. Emissions of both gases decreased by 1 percent from 1990, while the total population of abandoned oil wells increased 27 percent. Emissions of both gases decreased by less than 1 percent between 2017 and 2018 as a result of well plugging activities.

Abandoned gas wells. Abandoned gas wells emitted 54 kt CH_4 and 2 kt CO_2 in 2018. Emissions of both gases increased by 50 percent from 1990, as the total population of abandoned gas wells increased 79 percent. Emissions of both gases decreased by less than 1 percent between 2017 and 2018 as a result of well plugging activities.

Table 3-80: CH_4 Emissions from Abandoned Oil and Gas Wells (MMT CO_2 Eq.)

Activity	1990	2005	2014	2015	2016	2017	2018
Abandoned Oil Wells	5.7	5.9	5.8	5.8	5.8	5.7	5.7
Abandoned Gas Wells	0.9	1.1	1.3	1.3	1.4	1.4	1.4
Total	**6.6**	**6.9**	**7.1**	**7.1**	**7.2**	**7.1**	**7.0**

Note: Totals may not sum due to independent rounding.

Table 3-81: CH_4 Emissions from Abandoned Oil and Gas Wells (kt)

Activity	1990	2005	2014	2015	2016	2017	2018
Abandoned Oil Wells	227	236	232	233	234	227	227
Abandoned Gas Wells	36	43	52	53	55	55	54
Total	**263**	**278**	**284**	**286**	**289**	**282**	**281**

Note: Totals may not sum due to independent rounding.

Table 3-82: CO_2 Emissions from Abandoned Oil and Gas Wells (MMT CO_2)

Activity	1990	2005	2014	2015	2016	2017	2018
Abandoned Oil Wells	+	+	+	+	+	+	+
Abandoned Gas Wells	+	+	+	+	+	+	+
Total	**+**	**+**	**+**	**+**	**+**	**+**	**+**

+ Does not exceed 0.05 MMT CO_2.

Table 3-83: CO_2 Emissions from Abandoned Oil and Gas Wells (kt)

Activity	1990	2005	2014	2015	2016	2017	2018
Abandoned Oil Wells	5	5	5	5	5	5	5
Abandoned Gas Wells	2	2	2	2	2	2	2
Total	**6**	**7**	**7**	**7**	**7**	**7**	**7**

Note: Totals may not sum due to independent rounding.

Methodology

EPA developed abandoned well CH_4 emission factors using data from Kang et al. (2016) and Townsend-Small et al. (2016). Plugged and unplugged abandoned well CH_4 emission factors were developed at the national-level (emission data from Townsend-Small et al.) and for the Appalachia region (using emission data from measurements in Pennsylvania and Ohio conducted by Kang et al. and Townsend-Small et al., respectively). The

Appalachia region emissions factors were applied to abandoned wells in states in the Appalachian basin region, and the national-level emission factors were applied to all other abandoned wells.

EPA developed abandoned well CO_2 emission factors using the CH_4 emission factors and an assumed ratio of CO_2-to-CH_4 gas content, similar to the approach used to calculate CO_2 emissions for many sources in Petroleum Systems and Natural Gas Systems. For abandoned oil wells, EPA used the Petroleum Systems default production segment associated gas ratio of 0.020 MT CO_2/MT CH_4, which was derived through API TankCalc modeling runs. For abandoned gas wells, EPA used the Natural Gas Systems default production segment CH_4 and CO_2 gas content values (GRI/EPA 1996, GTI 2001) to develop a ratio of 0.044 MT CO_2/MT CH_4.

The total population of abandoned wells over the time series was estimated using historical data and DrillingInfo data. For the most recent year of the Inventory time series (year 2018), the prior year total counts are used as surrogate data, as the DrillingInfo query approach for the most recent year would likely overestimate abandoned well counts, because many wells might be spud and not reporting production—not because they are dry/abandoned, but due to the time required for completion. The abandoned well population was then split into plugged and unplugged wells by assuming that all abandoned wells were unplugged in 1950, using year-specific Drilling info data to calculate the fraction of abandoned wells plugged in 2016 (31 percent) and 2017 and 2018 (34 percent in both years), and applying linear interpolation between the 1950 value and 2016 value to calculate the plugged fraction for intermediate years. See the memorandum *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2016: Abandoned Wells in Natural Gas and Petroleum Systems (2018 Abandoned Wells Memo)* for details.[89]

Abandoned Oil Wells

Table 3-84: Abandoned Oil Wells Activity Data, CH_4 and CO_2 Emissions (metric tons)

Source	1990	2005	2014	2015	2016	2017	2018
Plugged abandoned oil wells	387,506	617,887	759,781	780,434	801,199	882,850	889,068
Unplugged abandoned oil wells	1,688,445	1,789,493	1,784,161	1,792,458	1,800,130	1,750,802	1,744,585
Total Abandoned Oil Wells	2,075,950	2,407,380	2,543,943	2,572,893	2,601,329	2,633,652	2,633,652
Abandoned oil wells in Appalachia	26%	24%	23%	23%	23%	23%	23%
Abandoned oil wells outside of Appalachia	74%	76%	77%	77%	77%	77%	77%
CH_4 from plugged abandoned oil wells (MT)	318	477	564	577	592	652	657
CH_4 from unplugged abandoned oil wells (MT)	226,740	235,212	231,461	232,197	233,191	226,801	225,995
Total CH_4 from Abandoned oil wells (MT)	**227,058**	**235,688**	**232,025**	**232,773**	**233,782**	**227,453**	**226,652**
Total CO_2 from Abandoned oil wells (MT)	**4,607**	**4,782**	**4,708**	**4,723**	**4,744**	**4,615**	**4,599**

[89] See <https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems>.

Abandoned Gas Wells

Table 3-85: Abandoned Gas Wells Activity Data, CH_4 and CO_2 Emissions (metric tons)

Source	1990	2005	2014	2015	2016	2017	2018
Plugged abandoned gas wells	60,126	104,652	154,844	162,215	171,979	193,375	194,736
Unplugged abandoned gas wells	261,982	303,089	363,614	372,566	386,402	383,486	382,124
Total Abandoned Gas Wells	322,108	407,741	518,458	534,781	558,381	576,861	576,861
Abandoned gas wells in Appalachia	28%	29%	30%	30%	30%	30%	30%
Abandoned gas wells outside of Appalachia	72%	71%	70%	70%	70%	70%	70%
CH_4 from plugged abandoned gas wells (MT)	53	97	147	155	164	185	186
CH_4 from unplugged abandoned gas wells (MT)	36,199	42,582	51,591	52,919	54,884	54,470	54,276
Total CH_4 from abandoned gas wells (MT)	**36,253**	**42,679**	**51,738**	**53,074**	**55,048**	**54,654**	**54,462**
Total CO_2 from abandoned gas wells (MT)	**1,589**	**1,870**	**2,268**	**2,326**	**2,413**	**2,395**	**2,387**

Uncertainty and Time-Series Consistency

To characterize uncertainty surrounding estimates of abandoned well emissions, EPA conducted a quantitative uncertainty analysis using the IPCC Approach 2 methodology (Monte Carlo simulation technique). See the *2018 Abandoned Wells Memo* for details of the uncertainty analysis methods. EPA used Microsoft Excel's @RISK add-in tool to estimate the 95 percent confidence bound around total methane emissions from abandoned oil and gas wells in year 2018, then applied the calculated bounds to both CH_4 and CO_2 emissions estimates for each population. The @RISK add-in provides for the specification of probability density functions (PDFs) for key variables within a computational structure that mirrors the calculation of the inventory estimate. EPA used measurement data from the Kang et al. (2016) and Townsend-Small et al. (2016) studies to characterize the CH_4 emission factor PDFs. For activity data inputs (e.g., total count of abandoned wells, split between plugged and unplugged), EPA assigned default uncertainty bounds of +/- 10 percent based on expert judgment.

The IPCC guidance notes that in using this method, "some uncertainties that are not addressed by statistical means may exist, including those arising from omissions or double counting, or other conceptual errors, or from incomplete understanding of the processes that may lead to inaccuracies in estimates developed from models." As a result, the understanding of the uncertainty of emission estimates for this category evolves and improves as the underlying methodologies and datasets improve. The uncertainty bounds reported below only reflect those uncertainties that EPA has been able to quantify and do not incorporate considerations such as modeling uncertainty, data representativeness, measurement errors, misreporting or misclassification.

The results presented below in Table 3-86 provide the 95 percent confidence bound within which actual emissions from abandoned oil and gas wells are likely to fall for the year 2018, using the recommended IPCC methodology. Abandoned oil well CH_4 emissions in 2018 were estimated to be between 1.0 and 18.1 MMT CO_2 Eq., while abandoned gas well CH_4 emissions were estimated to be between 0.2 and 4.3 MMT CO_2 Eq. at a 95 percent confidence level. Uncertainty bounds for other years of the time series have not been calculated, but uncertainty is expected to vary over the time series.

Table 3-86: Approach 2 Quantitative Uncertainty Estimates for CH_4 and CO_2 Emissions from Petroleum and Natural Gas Systems (MMT CO_2 Eq. and Percent)

Source	Gas	2018 Emission Estimate	Uncertainty Range Relative to Emission Estimate[a]

		(MMT CO_2 Eq.)[b]	(MMT CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Abandoned Oil Wells	CH_4	5.7	1.0	18.1	-83%	+219%
Abandoned Gas Wells	CH_4	1.4	0.2	4.3	-83%	+219%
Abandoned Oil Wells	CO_2	0.005	0.001	0.015	-83%	+219%
Abandoned Gas Wells	CO_2	0.002	0.0004	0.008	-83%	+219%

[a] Range of emission estimates estimated by applying the 95 percent confidence intervals obtained from the Monte Carlo Simulation analysis conducted for total abandoned oil and gas well CH_4 emissions in year 2018.

[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.

To calculate a time series of emissions for abandoned wells, EPA developed annual activity data for 1990 through 2018 by summing an estimate of total abandoned wells not included in recent databases, to an annual estimate of abandoned wells in the Enverus DrillingInfo data set (with year 2017 estimates used as surrogates for year 2018 data). As discussed above, the abandoned well population was split into plugged and unplugged wells by assuming that all abandoned wells were unplugged in 1950, using year-specific Drilling info data to calculate the fraction of abandoned wells plugged in 2016 through 2018, and applying linear interpolation between the 1950 value and 2016 value to calculate plugged fraction for intermediate years. The same emission factors were applied to the corresponding categories for each year of the time series.

QA/QC and Verification Discussion

The 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 to assess whether the assumptions in the Inventory are consistent with industry practices and whether new data is available that could be considered for updates to the estimates. As in previous years, EPA conducted early engagement and communication with stakeholders on updates prior to public review. EPA held a stakeholder webinar on greenhouse gas data for oil and gas in September of 2019, and a workshop in November of 2019.

Recalculations Discussion

The counts of national abandoned wells were recalculated across the time series to use the latest DrillingInfo data, which resulted in minor changes to the total abandoned well population and the allocation between petroleum and natural gas systems. The minor changes resulted from changes to the year-specific data for 1990 to 2017 as processed from DrillingInfo, which led EPA to recalculate the estimate of historical wells not included in the DrillingInfo data set (which decreased from 1,108,648 to 1,075,849 historical wells not included in DrillingInfo). Compared with the previous Inventory, counts of abandoned oil and gas wells are on average 0.3 percent and 0.8 percent, respectively, higher over 1990 to 2017. The impact was largest in recent years, with abandoned oil and gas well counts recalculated to be 1.4 percent and 3.1 percent, respectively, higher for 2017 comparing the previous Inventory values to the current Inventory values; this change is primarily due to the use of year-specific data for year 2017 (as the previous Inventory used year 2016 estimates as surrogate for year 2017 per the established methodology described above).

Planned Improvements

The abandoned wells source was added to the Inventory in 2018. EPA will continue to assess new data and stakeholder feedback on considerations (such as disaggregation of the well population into regions other than Appalachia and non-Appalachia, and emission factor data from regions not included in the measurement studies

on which current emission factors are based) to improve the abandoned well count estimates and emission factors.

3.9 Energy Sources of Precursor Greenhouse Gas Emissions

In addition to the main greenhouse gases addressed above, energy-related activities are also sources of precursor gases. The reporting requirements of the UNFCCC[90] request that information be provided on precursor greenhouse gases, which include carbon monoxide (CO), nitrogen oxides (NO_x), non-CH_4 volatile organic compounds (NMVOCs), and sulfur dioxide (SO_2). These gases are not direct greenhouse gases, but indirectly affect terrestrial radiation absorption by influencing the formation and destruction of tropospheric and stratospheric ozone, or, in the case of SO_2, by affecting the absorptive characteristics of the atmosphere. Additionally, some of these gases may react with other chemical compounds in the atmosphere to form compounds that are greenhouse gases. Total emissions of NO_x, CO, and NMVOCs from energy-related activities from 1990 to 2018 are reported in Table 3-87. Sulfur dioxide emissions are presented in Section 2.3 of the Trends chapter and Annex 6.3.

Table 3-87: NO_x, CO, and NMVOC Emissions from Energy-Related Activities (kt)

Gas/Activity	1990	2005	2014	2015	2016	2017	2018
NO_x	**21,106**	**16,602**	**10,198**	**9,523**	**9,037**	**8,555**	**8,154**
Mobile Fossil Fuel Combustion	10,862	10,295	6,138	5,740	5,413	5,051	4,689
Stationary Fossil Fuel Combustion	10,023	5,858	3,313	3,036	2,876	2,757	2,719
Oil and Gas Activities	139	321	650	650	650	650	650
Waste Combustion	82	128	97	97	97	97	97
International Bunker Fuels[a]	*1,956*	*1,704*	*1,211*	*1,363*	*1,470*	*1,481*	*1,462*
CO	**125,640**	**64,985**	**40,234**	**39,258**	**36,885**	**35,211**	**33,537**
Mobile Fossil Fuel Combustion	119,360	58,615	34,135	33,159	30,786	29,112	27,438
Stationary Fossil Fuel Combustion	5,000	4,648	3,686	3,686	3,686	3,686	3,686
Waste Combustion	978	1,403	1,776	1,776	1,776	1,776	1,776
Oil and Gas Activities	302	318	637	637	637	637	637
International Bunker Fuels[a]	*103*	*133*	*137*	*144*	*150*	*156*	*160*
NMVOCs	**12,620**	**7,191**	**7,247**	**7,082**	**6,835**	**6,629**	**6,423**
Mobile Fossil Fuel Combustion	10,932	5,724	3,754	3,589	3,342	3,137	2,931
Oil and Gas Activities	554	510	2,853	2,853	2,853	2,853	2,853
Stationary Fossil Fuel Combustion	912	716	497	497	497	497	497
Waste Combustion	222	241	143	143	143	143	143
International Bunker Fuels[a]	*57*	*54*	*42*	*47*	*50*	*51*	*51*

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

Methodology

Emission estimates for 1990 through 2018 were obtained from data published on the National Emission Inventory (NEI) Air Pollutant Emission Trends web site (EPA 2019), and disaggregated based on EPA (2003). 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.

[90] See <http://unfccc.int/resource/docs/2013/cop19/eng/10a03.pdf>.

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 2018. Details on the emission trends through time are described in more detail in the Methodology section, above.

3.10 International Bunker Fuels (CRF 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.[91] 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).[92]

Two transport modes are addressed under the IPCC definition of international bunker fuels: aviation and marine.[93] 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 three different modes of air traffic: civil aviation, military aviation, and general aviation. 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

[91] 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).

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

[93] 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).

United States are reported here. The standard fuel used for civil and military aviation is kerosene-type jet fuel, while the typical fuel used for general aviation is aviation gasoline.[94]

Emissions of CO_2 from aircraft are essentially a function of fuel consumption. 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 reported as 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 2018 from the combustion of international bunker fuels from both aviation and marine activities were 123.3 MMT CO_2 Eq., or 18 percent above emissions in 1990 (see Table 3-88 and Table 3-89). Emissions from international flights and international shipping voyages departing from the United States have increased by 112.4 percent and decreased by 36.9 percent, respectively, since 1990. The majority of these emissions were in the form of CO_2; however, small amounts of CH_4 (from marine transport modes) and N_2O were also emitted.

Table 3-88: CO_2, CH_4, and N_2O Emissions from International Bunker Fuels (MMT CO_2 Eq.)

Gas/Mode	1990	2005	2014	2015	2016	2017	2018
CO_2	**103.5**	**113.1**	**103.4**	**110.9**	**116.6**	**120.1**	**122.1**
Aviation	38.0	60.1	69.6	71.9	74.1	77.7	80.8
Commercial	30.0	55.6	66.3	68.6	70.8	74.5	77.7
Military	8.1	4.5	3.3	3.3	3.3	3.2	3.1
Marine	65.4	53.0	33.8	38.9	42.5	42.4	41.3
CH_4	**0.2**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Aviation[a]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Marine	0.2	0.1	0.1	0.1	0.1	0.1	0.1
N_2O	**0.9**	**1.0**	**0.9**	**1.0**	**1.0**	**1.1**	**1.1**
Aviation	0.4	0.6	0.7	0.7	0.7	0.7	0.8
Marine	0.5	0.4	0.3	0.3	0.3	0.3	0.3
Total	**104.5**	**114.2**	**104.4**	**112.0**	**117.7**	**121.3**	**123.3**

Notes: Totals may not sum due to independent rounding. Includes aircraft cruise altitude emissions.
[a] CH_4 emissions from aviation are estimated to be zero.

Table 3-89: CO_2, CH_4, and N_2O Emissions from International Bunker Fuels (kt)

Gas/Mode	1990	2005	2014	2015	2016	2017	2018
CO_2	**103,463**	**113,139**	**103,400**	**110,887**	**116,594**	**120,107**	**122,088**
Aviation	38,034	60,125	69,609	71,942	74,059	77,696	80,788
Marine	65,429	53,014	33,791	38,946	42,535	42,412	41,300
CH_4	**7**	**5**	**3**	**4**	**4**	**4**	**4**
Aviation[a]	0	0	0	0	0	0	0
Marine	7	5	3	4	4	4	4
N_2O	**3**	**3**	**3**	**3**	**3**	**4**	**4**

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

Aviation	1		2		2	2	2	3	3
Marine	2		1		1	1	1	1	1

Notes: Totals may not sum due to independent rounding. Includes aircraft cruise altitude emissions.
[a] CH_4 emissions from aviation are estimated to be zero.

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 (2019) and USAF (1998), and heat content for jet fuel was taken from EIA (2019).

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 and 2000 through 2018 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 2018 were obtained directly from FAA's AEDT model (FAA 2019). The radar-informed method that was used to estimate CO_2 emissions for commercial aircraft for 1990 and 2000 through 2018 was not possible for 1991 through 1999 because the radar dataset was not available for years prior to 2000. FAA developed Official Airline Guide (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. See Annex 3.3 for more information on the methodology for estimating emissions from commercial aircraft jet fuel consumption.

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 2019). 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 3-90 See Annex 3.8 for additional discussion of military data.

Table 3-90: Aviation Jet Fuel Consumption for International Transport (Million Gallons)

Nationality	1990	2005	2014	2015	2016	2017	2018
U.S. and Foreign Carriers	3,222	5,983	7,126	7,383	7,610	8,011	8,352
U.S. Military	862	462	339	341	333	326	315
Total	**4,084**	**6,445**	**7,465**	**7,725**	**7,943**	**8,338**	**8,667**

Note: Totals may not sum due to independent rounding.

In order to quantify the civilian international component of marine bunker fuels, activity data on distillate diesel and residual fuel oil consumption by cargo or passenger carrying marine vessels departing from U.S. ports were collected for individual shipping agents on a monthly basis by the U.S. Customs and Border Protection. This information was then reported in unpublished data collected by the Foreign Trade Division of the U.S. Department of Commerce's Bureau of the Census (DOC 1991 through 2019) for 1990 through 2001, 2007 through 2018, 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 (2019). 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 3-91.

Table 3-91: Marine Fuel Consumption for International Transport (Million Gallons)

Fuel Type	1990	2005	2014	2015	2016	2017	2018
Residual Fuel Oil	4,781	3,881	2,466	2,718	3,011	2,975	2,790
Distillate Diesel Fuel & Other	617	444	261	492	534	568	684
U.S. Military Naval Fuels	522	471	331	326	314	307	285
Total	**5,920**	**4,796**	**3,058**	**3,536**	**3,858**	**3,850**	**3,759**

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.[95] 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.

[95] See uncertainty discussions under section 3.1 Carbon Dioxide Emissions from Fossil Fuel Combustion.

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

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

Although aggregate fuel consumption data have been used to estimate emissions from aviation, the recommended method for estimating emissions of gases other than CO_2 in the *2006 IPCC Guidelines* (IPCC 2006) is to use data by specific aircraft type, number of individual flights and, ideally, movement data to better differentiate between domestic and international aviation and to facilitate estimating the effects of changes in technologies. The IPCC also recommends that cruise altitude emissions be estimated separately using fuel consumption data, while landing and take-off (LTO) cycle data be used to estimate near-ground level emissions of gases other than CO_2.[96]

There is also concern regarding the reliability of the existing DOC (1991 through 2019) 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 2018. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

In order to ensure the quality of the emission estimates from international bunker fuels, General (IPCC Tier 1) and category-specific (Tier 2) Quality Assurance/Quality Control (QA/QC) procedures were implemented consistent with the U.S. Inventory QA/QC plan outlined in Annex 8. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and emission factor sources and methodology used for estimating

[96] 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.

CO_2, CH_4, and N_2O emissions 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

A longer-term effort is underway to consider the feasibility of including data from a broader range of domestic and international sources for bunker fuels. Potential sources include the International Maritime Organization (IMO) and their ongoing greenhouse gas analysis work, data from the U.S. Coast Guard on vehicle operation currently used in criteria pollutant modeling and data from the International Energy Agency.

3.11 Wood Biomass and Biofuels Consumption (CRF 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.

Therefore, CO_2 emissions from wood biomass and biofuel consumption are not included specifically in summing energy sector totals. However, they are presented here for informational purposes and to provide detail on wood biomass and biofuels consumption.

In 2018, total CO_2 emissions from the burning of woody biomass in the industrial, residential, commercial, and electric power sectors were approximately 229.1 MMT CO_2 Eq. (229,085 kt) (see Table 3-92 and Table 3-93). As the largest consumer of woody biomass, the industrial sector was responsible for 63.0 percent of the CO_2 emissions from this source. The residential sector was the second largest emitter, constituting 23.3 percent of the total, while the commercial and electric power sectors accounted for the remainder.

Table 3-92: CO_2 Emissions from Wood Consumption by End-Use Sector (MMT CO_2 Eq.)

End-Use Sector	1990	2005	2014	2015	2016	2017	2018
Industrial	135.3	136.3	140.3	138.5	138.3	144.5	144.3
Residential	59.8	44.3	59.7	52.9	46.2	44.6	53.3
Commercial	6.8	7.2	7.9	8.2	8.6	8.6	8.7
Electric Power	13.3	19.1	25.9	25.1	23.1	23.6	22.8
Total	**215.2**	**206.9**	**233.8**	**224.7**	**216.3**	**221.4**	**229.1**

Note: Totals may not sum due to independent rounding.

Table 3-93: CO_2 Emissions from Wood Consumption by End-Use Sector (kt)

End-Use Sector	1990	2005	2014	2015	2016	2017	2018
Industrial	135,348	136,269	140,331	138,537	138,339	144,502	144,285
Residential	59,808	44,340	59,657	52,872	46,180	44,649	53,336
Commercial	6,779	7,218	7,867	8,176	8,635	8,634	8,669
Electric Power	13,252	19,074	25,908	25,146	23,140	23,647	22,795
Total	**215,186**	**206,901**	**233,762**	**224,730**	**216,293**	**221,432**	**229,085**

Note: Totals may not sum due to independent rounding.

The transportation sector is responsible for most of the fuel ethanol consumption in the United States. Ethanol used for fuel 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 2018, the United States transportation sector consumed an estimated 1,148.2 trillion Btu of ethanol (95 percent of total), and as a result, produced approximately 78.6 MMT CO_2 Eq. (78,603 kt) (see Table 3-94 and Table 3-95) of CO_2 emissions. Smaller quantities of ethanol were also used in the industrial and commercial sectors. Ethanol fuel 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 3-94: CO_2 Emissions from Ethanol Consumption (MMT CO_2 Eq.)

End-Use Sector	1990	2005	2014	2015	2016	2017	2018
Transportation[a]	4.1	21.6	74.0	74.2	76.9	77.7	78.6
Industrial	0.1	1.2	1.6	1.9	1.8	1.9	1.4
Commercial	0.1	0.2	0.4	2.8	2.6	2.5	1.9
Total	**4.2**	**22.9**	**76.1**	**78.9**	**81.2**	**82.1**	**81.9**

Note: Totals may not sum due to independent rounding.
[a] See Annex 3.2, Table A-98 for additional information on transportation consumption of these fuels.

Table 3-95: CO_2 Emissions from Ethanol Consumption (kt)

End-Use Sector	1990	2005	2014	2015	2016	2017	2018
Transportation[a]	4,059	21,616	74,006	74,187	76,903	77,671	78,603
Industrial	105	1,176	1,647	1,931	1,789	1,868	1,401
Commercial	63	151	422	2,816	2,558	2,550	1,913
Total	**4,227**	**22,943**	**76,075**	**78,934**	**81,250**	**82,088**	**81,917**

Note: Totals may not sum due to independent rounding.
[a] See Annex 3.2, Table A-98 for additional information on transportation consumption of these fuels.

The transportation sector is assumed to be responsible for all of the biodiesel consumption in the United States (EIA 2019a). 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 2019b).

In 2018, the United States consumed an estimated 242.9 trillion Btu of biodiesel, and as a result, produced approximately 17.9 MMT CO_2 Eq. (17,936 kt) (see Table 3-96 and Table 3-97) 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 2019b). There was no measured biodiesel consumption prior to 2001 EIA (2019a).

Table 3-96: CO_2 Emissions from Biodiesel Consumption (MMT CO_2 Eq.)

End-Use Sector	1990	2005	2014	2015	2016	2017	2018
Transportation[a]	NO	0.9	13.3	14.1	19.6	18.7	17.9
Total	**NO**	**0.9**	**13.3**	**14.1**	**19.6**	**18.7**	**17.9**

Note: Totals may not sum due to independent rounding.
NO (Not Occurring)
[a] See Annex 3.2, Table A-98 for additional information on transportation consumption of these fuels.

Table 3-97: CO_2 Emissions from Biodiesel Consumption (kt)

End-Use Sector	1990	2005	2014	2015	2016	2017	2018
Transportation[a]	NO	856	13,349	14,077	19,648	18,705	17,936
Total	**NO**	**856**	**13,349**	**14,077**	**19,648**	**18,705**	**17,936**

Note: Totals may not sum due to independent rounding.
NO (Not Occurring)
[a] See Annex 3.2, Table A-98 for additional information on transportation consumption of these fuels.

Methodology

Woody biomass emissions were estimated by applying two gross heat contents from EIA (Lindstrom 2006) to U.S. consumption data (EIA 2019a) (see Table 3-98), provided in energy units for the industrial, residential, commercial, and electric power 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. The woody biomass is assumed to contain black liquor and other wood wastes, have a moisture content of 12 percent, and undergo complete combustion to be converted into CO_2.

The amount of ethanol allocated across the transportation, industrial, and commercial sectors was based on the sector allocations of ethanol-blended motor gasoline. The sector allocations of ethanol-blended motor gasoline were determined using a bottom-up analysis conducted by EPA, as described in the Methodology section of 0 Fossil Fuel Combustion. Total U.S. ethanol consumption from EIA (2019a) was allocated to individual sectors using the same sector allocations as ethanol-blended motor gasoline. The emissions from ethanol consumption were calculated by applying an emission factor of 18.67 MMT C/QBtu (EPA 2010) to adjusted ethanol consumption estimates (see Table 3-99). 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 2019a) (see Table 3-100).[97]

Table 3-98: Woody Biomass Consumption by Sector (Trillion Btu)

End-Use Sector	1990	2005	2014	2015	2016	2017	2018
Industrial	1,441.9	1,451.7	1,495.0	1,475.9	1,473.8	1,539.4	1,537.1
Residential	580.0	430.0	578.5	512.7	447.8	433.0	517.2
Commercial	65.7	70.0	76.3	79.3	83.7	83.7	84.1
Electric Power	128.5	185.0	251.3	243.9	224.4	229.3	221.1
Total	**2,216.2**	**2,136.7**	**2,401.1**	**2,311.8**	**2,229.8**	**2,285.5**	**2,359.5**

Note: Totals may not sum due to independent rounding.

Table 3-99: Ethanol Consumption by Sector (Trillion Btu)

End-Use Sector	1990	2005	2014	2015	2016	2017	2018
Transportation	59.3	315.8	1,081.1	1,083.7	1,123.4	1,134.6	1,148.2
Industrial	1.5	17.2	24.1	28.2	26.1	27.2	20.5
Commercial	0.9	2.2	6.2	41.1	37.4	37.2	27.9
Total	**61.7**	**335.1**	**1,111.3**	**1,153.1**	**1,186.9**	**1,199.1**	**1,196.6**

Note: Totals may not sum due to independent rounding.

[97] CO_2 emissions from biodiesel do not include emissions associated with the C in the fuel that is from the methanol used in the process. Emissions from methanol use and combustion are assumed to be accounted for under Non-Energy Use of Fuels. See Annex 2.3 – Methodology for Estimating Carbon Emitted from Non-Energy Uses of Fossil Fuels.

Table 3-100: Biodiesel Consumption by Sector (Trillion Btu)

End-Use Sector	1990	2005	2014	2015	2016	2017	2018
Transportation	NO	11.6	180.8	190.6	266.1	253.3	242.9
Total	**NO**	**11.6**	**180.8**	**190.6**	**266.1**	**253.3**	**242.9**

Note: Totals may not sum due to independent rounding.
NO (Not Occurring)

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 for CO_2. 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 2018. Details on the emission trends through time are described in more detail in the Methodology section, above.

Recalculations Discussion

EIA (2019a) updated heat contents for fuel ethanol, which resulted in updated ethanol consumption statistics and CO_2 emissions from ethanol consumption increased by less than 0.01 percent in 2017 relative to the previous report. EIA (2019a) also updated biodiesel consumption statistics for 2016 and CO_2 emissions from biodiesel consumption increased by less than 0.01 percent relative to the previous report.

Planned Improvements

Future research will look into the availability of data on woody biomass heat contents and carbon emission factors the see if there are newer, improved data sources available for these factors.

The availability of facility-level combustion emissions through EPA's GHGRP will be examined to help better characterize the industrial sector's energy consumption in the United States, and further classify 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 EPA's GHGRP may also include industrial process emissions.[98] 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

[98] See <https://unfccc.int/resource/docs/2013/cop19/eng/10a03.pdf#page=2>.

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.[99]

Currently emission estimates from biomass and biomass-based fuels included in this Inventory are limited to woody biomass, ethanol, and biodiesel. Additional forms of biomass-based fuel consumption include biogas and the biogenic components of MSW. EPA will examine EIA data on biogas to see if it can be included in future inventories. EIA (2019a) 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. Sources of estimates for the biogenic fraction of MSW will be examined, including the GHGRP, EIA data, and EPA MSW characterization data.

Carbon dioxide emissions from biomass used in the electric power sector are calculated using woody biomass consumption data from EIA's *Monthly Energy Review* (EIA 2019a), whereas non-CO_2 biomass emissions from the electric power sector are estimated by applying technology and fuel use data from EPA's Clean Air Market Acid Rain Program dataset (EPA 2020) to fuel consumption data from EIA (2019a). There were significant discrepancies identified between the EIA woody biomass consumption data and the consumption data estimated using EPA's Acid Rain Program dataset (see the Methodology section for CH_4 and N_2O from Stationary Combustion). EPA will continue to investigate this discrepancy in order to apply a consistent approach to both CO_2 and non-CO_2 emission calculations for woody biomass consumption in the electric power sector.

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