

3. Energy

Energy-related activities were the primary sources of U.S. anthropogenic greenhouse gas emissions, accounting for 82.3 percent of total greenhouse gas emissions on a carbon dioxide (CO₂) equivalent basis in 2019.¹ This included 97, 41, and 10 percent of the nation's CO₂, methane (CH₄), and nitrous oxide (N₂O) emissions, respectively. Energy-related CO₂ emissions alone constituted 77.5 percent of U.S. greenhouse gas emissions from all sources on a CO₂-equivalent basis, while the non-CO₂ emissions from energy-related activities represented a much smaller portion of total national emissions (4.7 percent collectively).

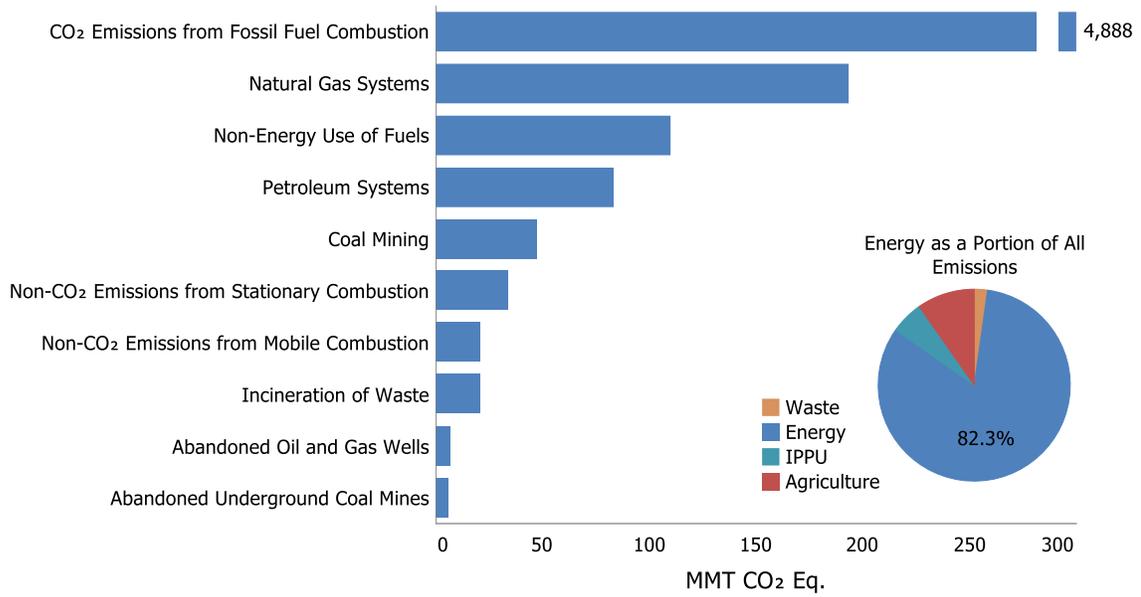
Emissions from fossil fuel combustion comprise the vast majority of energy-related emissions, with CO₂ being the primary gas emitted (see Figure 3-1 and Figure 3-2). Globally, approximately 33,100 million metric tons (MMT) of CO₂ were added to the atmosphere through the combustion of fossil fuels in 2018, of which the United States accounted for approximately 16 percent.² Due to their relative importance over time (see Figure 3-2), fossil fuel combustion-related CO₂ emissions are considered separately and in more detail than other energy-related emissions (see Figure 3-3).

Fossil fuel combustion also emits CH₄ and N₂O. Stationary combustion of fossil fuels was the third largest source of N₂O emissions in the United States and mobile fossil fuel combustion was the fifth 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 CH₄ emissions from natural gas systems, coal mining, and petroleum systems.

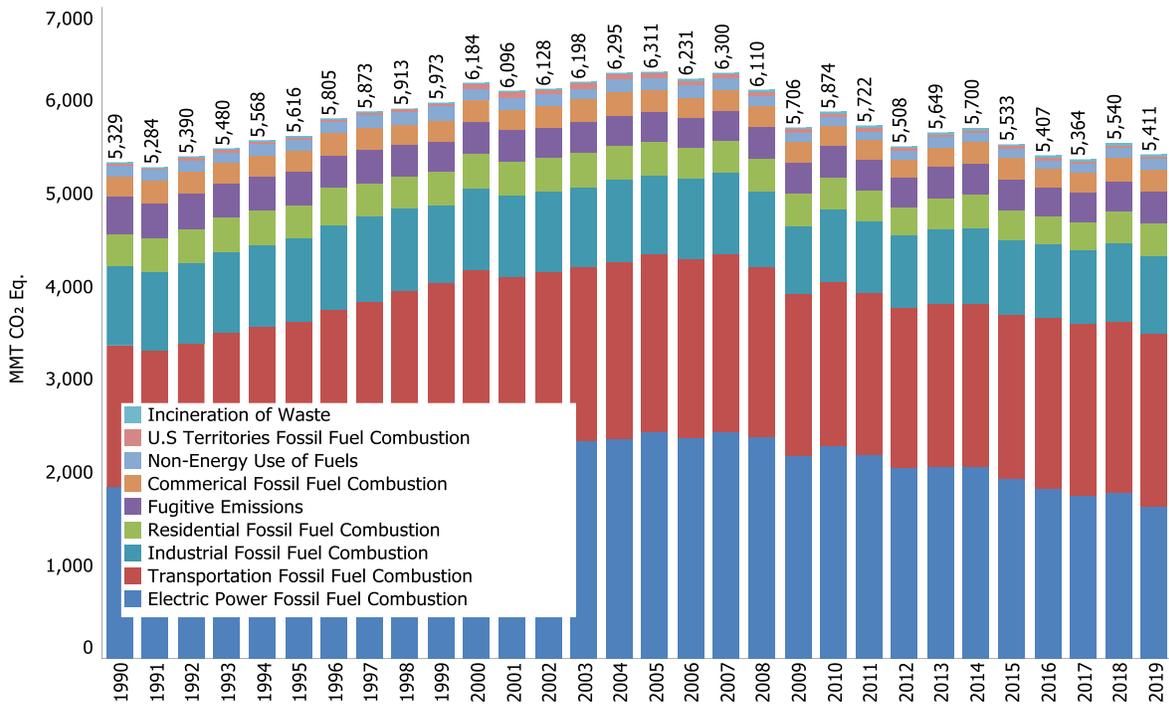
¹ Estimates are presented in units of million metric tons of carbon dioxide equivalent (MMT CO₂ Eq.), which weight each gas by its global warming potential, or GWP, value. See section on global warming potentials in the Executive Summary.

² Global CO₂ emissions from fossil fuel combustion were taken from International Energy Agency *CO₂ Emissions from Fossil Fuels Combustion Overview* Available at: <<https://webstore.iea.org/co2-emissions-from-fuel-combustion-2019>> (IEA 2019).

1 **Figure 3-1: 2019 Energy Chapter Greenhouse Gas Sources**

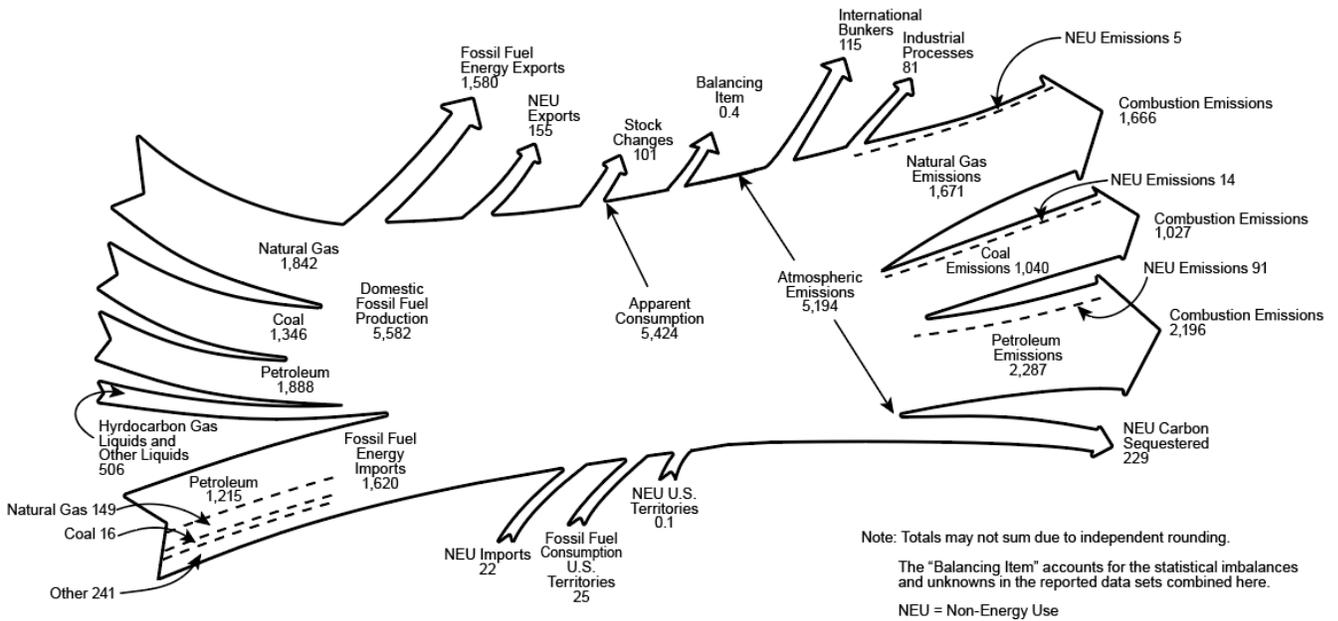


2
3 **Figure 3-2: Trends in Energy Chapter Greenhouse Gas Sources**



4

1 **Figure 3-3: 2019 U.S. Fossil Carbon Flows**



2

3 Table 3-1 summarizes emissions from the Energy sector in units of MMT CO₂ Eq., while unweighted gas emissions
 4 in kilotons (kt) are provided in Table 3-2. Overall, emissions due to energy-related activities were 5,410.8 MMT CO₂
 5 Eq. in 2019,³ an increase of 1.5 percent since 1990 and a decrease of 2.3 percent since 2018.

6 **Table 3-1: CO₂, CH₄, and N₂O Emissions from Energy (MMT CO₂ Eq.)**

Gas/Source	1990	2005	2015	2016	2017	2018	2019
CO₂	4,897.2	5,939.1	5,202.3	5,089.4	5,047.4	5,225.3	5,098.9
Fossil Fuel Combustion	4,731.5	5,753.8	5,013.8	4,922.0	4,870.4	5,023.1	4,888.5
<i>Transportation</i>	1,469.1	1,868.8	1,750.5	1,797.3	1,812.6	1,821.2	1,843.2
<i>Electric Power</i>	1,820.0	2,400.1	1,900.6	1,808.9	1,732.0	1,752.9	1,606.0
<i>Industrial</i>	853.8	844.0	790.3	787.0	794.1	838.0	837.6
<i>Residential</i>	338.6	359.1	318.1	292.3	294.6	339.5	338.8
<i>Commercial</i>	228.3	226.0	224.9	210.4	212.3	246.9	238.3
<i>U.S. Territories</i>	21.7	56.0	29.4	26.2	24.7	24.6	24.6
Non-Energy Use of Fuels	112.8	130.6	105.3	93.6	99.7	110.9	110.1
Petroleum Systems	9.7	12.1	32.4	21.9	24.8	36.6	43.3
Natural Gas Systems	32.0	25.2	29.2	30.1	31.2	33.9	36.9
Incineration of Waste	11.2	17.4	21.5	21.8	21.3	20.9	20.2
Abandoned Oil and Gas Wells	+	+	+	+	+	+	+
<i>Biomass-Wood^a</i>	215.2	206.9	224.7	215.7	211.5	219.8	216.5
<i>International Bunker Fuels^b</i>	103.5	113.2	110.8	116.5	120.0	122.0	116.1
<i>Biofuels-Ethanol^a</i>	4.2	22.9	78.9	81.2	82.1	81.9	82.6
<i>Biofuels-Biodiesel^a</i>	0.0	0.9	14.1	19.6	18.7	17.9	17.1
CH₄	361.4	295.3	277.9	266.0	267.4	266.9	268.0
Natural Gas Systems	187.7	163.7	148.6	146.7	147.6	150.8	156.4
Coal Mining	96.5	65.7	61.8	54.3	55.4	53.4	47.4
Petroleum Systems	48.5	40.6	43.0	40.8	40.9	38.5	40.2
Stationary Combustion	8.6	7.8	8.4	7.8	7.6	8.6	8.6

³ Following the current reporting requirements under the UNFCCC, this Inventory report presents CO₂ equivalent values based on the IPCC Fourth Assessment Report (AR4) GWP values. See the Introduction chapter for more information.

Abandoned Oil and Gas Wells	6.6	7.0	7.1	7.2	7.1	7.0	7.0
Abandoned Underground							
Coal Mines	7.2	6.6	6.4	6.7	6.4	6.2	5.9
Mobile Combustion	6.4	3.9	2.6	2.5	2.5	2.4	2.4
Incineration of Waste	+	+	+	+	+	+	+
<i>International Bunker Fuels^b</i>	0.2	0.1	0.1	0.1	0.1	0.1	0.1
N₂O	70.8	76.7	52.8	51.5	49.0	47.9	43.9
Stationary Combustion	25.1	34.3	30.4	29.9	28.4	28.2	24.9
Mobile Combustion	45.2	42.0	21.9	21.1	20.2	19.1	18.6
Incineration of Waste	0.5	0.4	0.4	0.4	0.4	0.4	0.4
Petroleum Systems	+	+	+	+	+	+	+
Natural Gas Systems	+	+	+	+	+	+	+
<i>International Bunker Fuels^b</i>	0.9	1.0	1.0	1.0	1.1	1.1	1.0
Total	5,329.4	6,311.1	5,532.9	5,406.9	5,363.8	5,540.1	5,410.8

Note: Totals may not sum due to independent rounding.

+ Does not exceed 0.05 MMT CO₂ 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.

1 **Table 3-2: CO₂, CH₄, and N₂O Emissions from Energy (kt)**

Gas/Source	1990	2005	2015	2016	2017	2018	2019
CO₂	4,897,173	5,939,096	5,202,253	5,089,393	5,047,368	5,225,328	5,098,938
Fossil Fuel Combustion	4,731,460	5,753,835	5,013,834	4,922,044	4,870,374	5,023,102	4,888,463
Non-Energy Use of							
Fuels	112,766	130,567	105,340	93,590	99,686	110,880	110,108
Petroleum Systems	9,732	12,071	32,434	21,855	24,813	36,588	43,308
Natural Gas Systems	32,026	25,182	29,159	30,067	31,207	33,864	36,854
Incineration of Waste	11,183	17,434	21,478	21,830	21,281	20,886	20,199
Abandoned Oil and							
Gas Wells	6	7	7	7	7	7	7
<i>Biomass-Wood^a</i>	215,186	206,901	224,730	215,712	211,511	219,794	216,533
<i>International Bunker</i>							
<i>Fuels^b</i>	103,471	113,188	110,803	116,501	120,009	122,005	116,056
<i>Biofuels-Ethanol^a</i>	4,227	22,943	78,934	81,250	82,088	81,917	82,578
<i>Biofuels-Biodiesel^a</i>	0	856	14,077	19,648	18,705	17,936	17,080
CH₄	14,458	11,811	11,117	10,640	10,697	10,677	10,718
Natural Gas Systems	7,508	6,547	5,944	5,868	5,905	6,034	6,258
Coal Mining	3,860	2,629	2,471	2,172	2,216	2,136	1,895
Petroleum Systems	1,941	1,624	1,720	1,631	1,635	1,540	1,607
Stationary Combustion	344	313	336	311	303	343	345
Abandoned Oil and							
Gas Wells	263	278	286	289	282	281	281
Abandoned							
Underground Coal							
Mines	288	264	256	268	257	247	237
Mobile Combustion	254	157	105	101	99	97	95
Incineration of Waste	+	+	+	+	+	+	+
<i>International Bunker</i>							
<i>Fuels^b</i>	7	5	4	4	4	4	4
N₂O	237	257	177	173	164	161	147
Stationary Combustion	84	115	102	100	95	95	83
Mobile Combustion	152	141	73	71	68	64	62
Incineration of Waste	2	1	1	1	1	1	1

Petroleum Systems	+		+		+	+	+	+	+
Natural Gas Systems	+		+		+	+	+	+	+
International Bunker Fuels ^b	3		3		3	3	4	4	3

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.

1 Each year, some emission and sink estimates in the Inventory are recalculated and revised with improved methods
2 and/or data. In general, recalculations are made to the U.S. greenhouse gas emission estimates either to
3 incorporate new methodologies or, most commonly, to update recent historical data. These improvements are
4 implemented consistently across the previous Inventory's time series (i.e., 1990 to 2018) to ensure that the trend
5 is accurate. Updates to CO₂ emissions from Fossil Fuel Combustion in the Energy sector resulted in an average
6 decrease over the time series of about 1.5 MMT CO₂ Eq. For more information on specific methodological updates,
7 please see the Recalculations section for each category, in this chapter.

8 **Box 3-1: Methodological Approach for Estimating and Reporting U.S. Emissions and Removals, including** 9 **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

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).

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 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 CO₂ 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 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 CO₂, CH₄, and N₂O. Given that CO₂ is the primary gas emitted from fossil fuel combustion and represents the largest share of U.S. total emissions, CO₂ 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 CO₂ from fossil fuel combustion also differ from the estimation of CH₄ and N₂O 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 CO₂, CH₄, and N₂O emissions from fossil fuel combustion are presented in Table 3-3 and Table 3-4.

Table 3-3: CO₂, CH₄, and N₂O Emissions from Fossil Fuel Combustion (MMT CO₂ Eq.)

Gas	1990	2005	2015	2016	2017	2018	2019
CO ₂	4,731.5	5,753.8	5,013.8	4,922.0	4,870.4	5,023.1	4,888.5
CH ₄	15.0	11.7	11.0	10.3	10.0	11.0	11.0
N ₂ O	70.3	76.3	52.3	51.0	48.6	47.4	43.4
Total	4,816.7	5,841.9	5,077.1	4,983.4	4,929.0	5,081.5	4,942.9

Note: Totals may not sum due to independent rounding.

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

1 **Table 3-4: CO₂, CH₄, and N₂O Emissions from Fossil Fuel Combustion (kt)**

Gas	1990	2005	2015	2016	2017	2018	2019
CO ₂	4,731,460	5,753,835	5,013,834	4,922,044	4,870,374	5,023,102	4,888,463
CH ₄	598	470	440	412	402	439	440
N ₂ O	236	256	175	171	163	159	146

2 **CO₂ from Fossil Fuel Combustion**

3 Carbon dioxide is the primary gas emitted from fossil fuel combustion and represents the largest share of U.S. total
4 greenhouse gas emissions. Carbon dioxide emissions from fossil fuel combustion are presented in Table 3-5. In
5 2019, CO₂ emissions from fossil fuel combustion decreased by 2.7 percent relative to the previous year (as shown
6 in Table 3-6). The decrease in CO₂ emissions from fossil fuel consumption was a result of a 1.3 percent decrease in
7 total energy use and reflects a continued shift from coal to natural gas. Carbon dioxide emissions from natural gas
8 consumption increased by 53.4 MMT CO₂ Eq. in 2019, a 3.3 percent increase from 2018, while CO₂ emissions from
9 coal consumption decreased by 184.3 MMT CO₂ Eq., a 15.2 percent decrease. The increase in natural gas
10 consumption and emissions in 2019 is observed across all sectors and is primarily driven by a shift away from coal
11 consumption in the Electric Power sector. In 2019, CO₂ emissions from fossil fuel combustion were 4,888.5 MMT
12 CO₂ Eq., or 3.3 percent above emissions in 1990 (see Table 3-5).⁶

13 **Table 3-5: CO₂ Emissions from Fossil Fuel Combustion by Fuel Type and Sector (MMT CO₂**
14 **Eq.)**

Fuel/Sector	1990	2005	2015	2016	2017	2018	2019
Coal	1,719.8	2,113.9	1,428.5	1,310.3	1,270.0	1,211.1	1,026.8
Residential	3.0	0.8	NO	NO	NO	NO	NO
Commercial	12.0	9.3	3.0	2.3	2.0	1.8	1.6
Industrial	157.8	118.0	70.0	62.8	58.5	54.0	49.2
Transportation	NO						
Electric Power	1,546.5	1,982.8	1,351.4	1,242.0	1,207.1	1,152.9	973.5
U.S. Territories	0.5	3.0	4.1	3.2	2.5	2.5	2.5
Natural Gas	1,000.0	1,167.0	1,460.2	1,471.8	1,450.4	1,612.3	1,665.7
Residential	237.8	262.2	252.7	238.4	241.5	273.8	275.3
Commercial	142.0	162.9	175.4	170.5	173.2	192.5	192.8
Industrial	408.8	388.6	464.4	474.5	485.3	515.1	524.3
Transportation	36.0	33.1	39.4	40.1	42.3	50.9	54.8
Electric Power	175.4	318.9	525.2	545.0	505.6	577.4	616.0
U.S. Territories	NO	1.3	3.0	3.4	2.5	2.5	2.5
Petroleum	2,011.1	2,472.5	2,124.8	2,139.5	2,149.5	2,199.3	2,195.5
Residential	97.8	96.1	65.4	54.0	53.2	65.7	63.5
Commercial	74.3	53.8	46.5	37.6	37.1	52.6	43.9
Industrial	287.2	337.3	255.9	249.7	250.3	269.0	264.0
Transportation	1,433.1	1,835.7	1,711.1	1,757.2	1,770.4	1,770.3	1,788.4
Electric Power	97.5	98.0	23.7	21.5	18.9	22.2	16.2
U.S. Territories	21.2	51.7	22.2	19.6	19.7	19.5	19.5
Geothermal^a	0.5	0.5	0.4	0.4	0.4	0.4	0.4
Electric Power	0.5	0.5	0.4	0.4	0.4	0.4	0.4
Total	4,731.5	5,753.8	5,013.8	4,922.0	4,870.4	5,023.1	4,888.5

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

⁶ An additional discussion of fossil fuel emission trends is presented in the Trends in U.S. Greenhouse Gas Emissions chapter.

^a Although not technically a fossil fuel, geothermal energy-related CO₂ emissions are included for reporting purposes. The source of CO₂ is non-condensable gases in subterranean heated water.

1 Trends in CO₂ emissions from fossil fuel combustion are influenced by many long-term and short-term factors. On
 2 a year-to-year basis, the overall demand for fossil fuels in the United States and other countries generally
 3 fluctuates in response to changes in general economic conditions, energy prices, weather, and the availability of
 4 non-fossil alternatives. For example, in a year with increased consumption of goods and services, low fuel prices,
 5 severe summer and winter weather conditions, nuclear plant closures, and lower precipitation feeding
 6 hydroelectric dams, there would likely be proportionally greater fossil fuel consumption than a year with poor
 7 economic performance, high fuel prices, mild temperatures, and increased output from nuclear and hydroelectric
 8 plants.

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

14 Carbon dioxide emissions also depend on the source of energy and its carbon (C) intensity. The amount of C in
 15 fuels varies significantly by fuel type. For example, coal contains the highest amount of C per unit of useful energy.
 16 Petroleum has roughly 75 percent of the C per unit of energy as coal, and natural gas has only about 55 percent.⁷
 17 Table 3-6 shows annual changes in emissions during the last five years for coal, petroleum, and natural gas in
 18 selected sectors.

19 **Table 3-6: Annual Change in CO₂ Emissions and Total 2019 CO₂ Emissions from Fossil Fuel**
 20 **Combustion for Selected Fuels and Sectors (MMT CO₂ Eq. and Percent)**

Sector	Fuel Type	2015 to 2016		2016 to 2017		2017 to 2018		2018 to 2019		Total 2019
Electric Power	Coal	-109.4	-8.1%	-34.9	-2.8%	-54.2	-4.5%	-179.3	-15.6%	973.5
Electric Power	Natural Gas	19.8	3.8%	-39.4	-7.2%	71.8	14.2%	38.5	6.7%	616.0
Electric Power	Petroleum	-2.2	-9.4%	-2.5	-11.8%	3.3	17.4%	-6.1	-27.3%	16.2
Transportation	Petroleum	46.1	2.7%	13.2	0.7%	-0.1	0.0%	18.1	1.0%	1,788.4
Residential	Natural Gas	-14.3	-5.7%	3.1	1.3%	32.3	13.4%	1.5	0.5%	275.3
Commercial	Natural Gas	-4.9	-2.8%	2.6	1.6%	19.3	11.2%	0.3	0.1%	192.8
Industrial	Natural Gas	10.1	2.2%	10.8	2.3%	29.7	6.1%	9.3	1.8%	524.3
Electric Power	All Fuels^a	-91.8	-4.8%	-76.8	-4.2%	20.9	1.2%	-146.9	-8.4%	1,606.0
Transportation	All Fuels^a	46.8	2.7%	15.4	0.9%	8.6	0.5%	22.0	1.2%	1,843.2
Residential	All Fuels^a	-25.7	-8.1%	2.3	0.8%	44.9	15.2%	-0.7	-0.2%	338.8
Commercial	All Fuels^a	-14.5	-6.4%	1.9	0.9%	34.6	16.3%	-8.6	-3.5%	238.3
Industrial	All Fuels^a	-3.3	-0.4%	7.0	0.9%	44.0	5.5%	-0.4	(+)%	837.6
All Sectors^a	All Fuels^a	-91.8	-1.8%	-51.7	-1.0%	152.7	3.1%	-134.6	-2.7%	4,888.5

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

21 As shown in Table 3-6, recent trends in CO₂ emissions from fossil fuel combustion show a 1.8 percent decrease
 22 from 2015 to 2016, a 1.0 percent decrease from 2016 to 2017, a 2.9 percent increase from 2017 to 2018, and a 2.7
 23 percent decrease from 2018 to 2019. These changes contributed to an overall 2.5 percent decrease in CO₂
 24 emissions from fossil fuel combustion from 2015 to 2019.

25 Trends in CO₂ emissions from fossil fuel combustion over the past five years are largely driven by the electric
 26 power sector, which until recently has historically accounted for the largest portion of these emissions. The types
 27 of fuels consumed to produce electricity have changed in recent years. Electric power sector consumption of
 28 natural gas primarily increased due to increased production capacity as natural gas-fired plants replaced coal-fired

⁷ Based on national aggregate carbon content of all coal, natural gas, and petroleum fuels combusted in the United States. See Annex 2.2 for more details on fuel carbon contents.

1 plants and increased electricity demand related to heating and cooling needs (EIA 2018; EIA 2020f). Total electric
2 power generation increased by 0.01 percent from 2015 to 2016, decreased by 1.0 percent from 2016 to 2017,
3 increased by 3.6 percent from 2017 to 2018 and decreased by 1.4 percent from 2018 to 2019. Carbon dioxide
4 emissions decreased from 2018 to 2019 by 8.4 percent due to increasing electric power generation from natural
5 gas and decreasing generation from petroleum and coal. Carbon dioxide emissions from coal consumption for
6 electric power generation decreased by 28.0 percent since 2015, which can be largely attributed to a shift to the
7 use of less-CO₂-intensive natural gas to generate electricity and a rapid increase in renewable energy capacity
8 additions in the electric power sector in recent years.

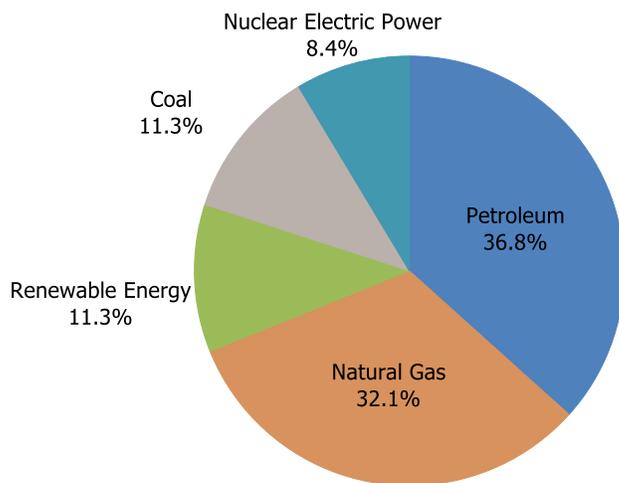
9 The trends in CO₂ emissions from fossil fuel combustion over the past five years also follow changes in heating
10 degree days (see Box 3-2). Emissions from natural gas consumption in the residential and commercial sectors
11 increased by 8.2 percent and 9.0 percent from 2015 to 2019, respectively. This trend can be largely attributed to a
12 5.3 percent increase in heating degree days from 2015 to 2019, which led to an increased demand for heating fuel
13 and electricity for heat in these sectors. Industrial consumption of natural gas is dependent on market effects of
14 supply and demand in addition to weather-related heating needs.

15 Petroleum use in the transportation sector is another major driver of emissions, representing the largest source of
16 CO₂ emissions from fossil fuel combustion in 2019. Emissions from petroleum consumption for transportation have
17 increased by 4.5 percent since 2015 and are primarily attributed to a 5.6 percent increase in vehicle miles traveled
18 (VMT) over the same time period. Beginning with 2017, the transportation sector is the largest source of national
19 CO₂ emissions – whereas in prior years, electric power was the largest source sector.

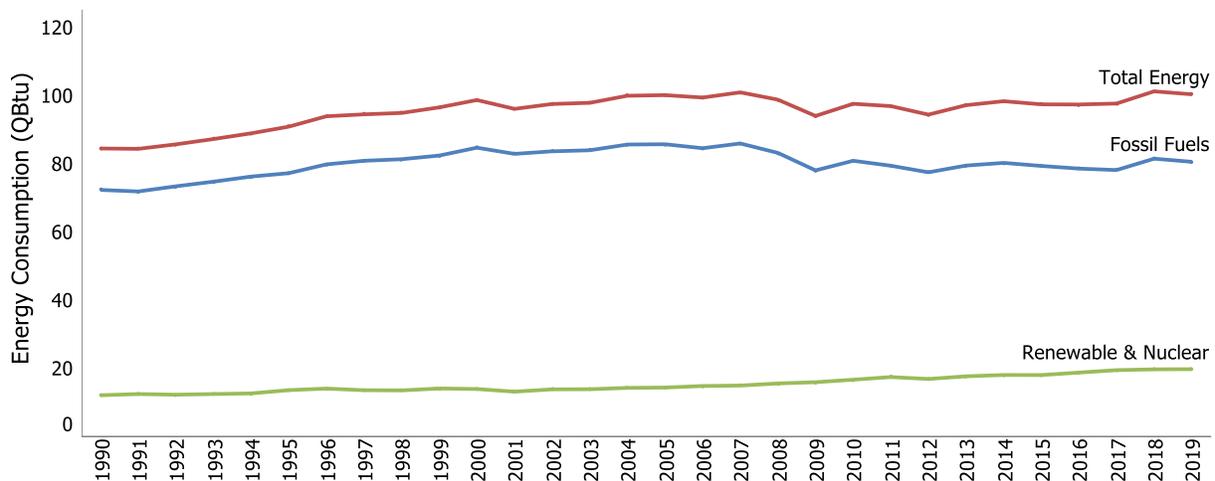
20 In the United States, 80 percent of the energy used in 2019 was produced through the combustion of fossil fuels
21 such as petroleum, natural gas, and coal (see Figure 3-4 and Figure 3-5). Specifically, petroleum supplied the
22 largest share of domestic energy demands, accounting for 37 percent of total U.S. energy used in 2019. Natural gas
23 and coal followed in order of energy demand importance, accounting for approximately 32 percent and 11 percent
24 of total U.S. energy used, respectively. Petroleum was consumed primarily in the transportation end-use sector
25 and the majority of coal was used in the electric power sector. Natural gas was broadly consumed in all end-use
26 sectors except transportation (see Figure 3-6) (EIA 2020c). The remaining portion of energy used in 2019 was
27 supplied by nuclear electric power (8 percent) and by a variety of renewable energy sources (11 percent), primarily
28 hydroelectric power, wind energy, and biofuels (EIA 2020c).⁸

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.

1 **Figure 3-4: 2019 U.S. Energy Use by Energy Source**

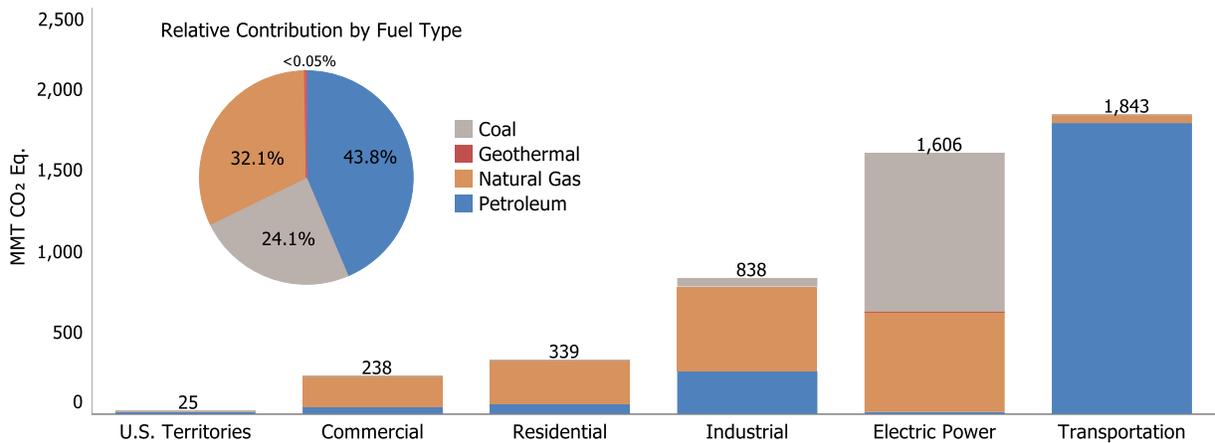


2
3
4 **Figure 3-5: Annual U.S. Energy Use**



5
6

1 **Figure 3-6: 2019 CO₂ Emissions from Fossil Fuel Combustion by Sector and Fuel Type**



2
 3 Fossil fuels are generally combusted for the purpose of producing energy for useful heat and work. During the
 4 combustion process, the C stored in the fuels is oxidized and emitted as CO₂ and smaller amounts of other gases,
 5 including CH₄, carbon monoxide (CO), and non-methane volatile organic compounds (NMVOCs).⁹ These other C-
 6 containing non-CO₂ gases are emitted as a byproduct of incomplete fuel combustion, but are, for the most part,
 7 eventually oxidized to CO₂ in the atmosphere. Therefore, as per IPCC guidelines it is assumed all of the C in fossil
 8 fuels used to produce energy is eventually converted to atmospheric CO₂.

9 **Box 3-2: Weather and Non-Fossil Energy Effects on CO₂ Emissions from Fossil Fuel Combustion Trends**

The United States in 2019 experienced a slightly colder winter overall compared to 2018, as heating degree days increased 0.6 percent. Colder winter conditions compared to 2018 impacted the amount of energy required for heating. However, in 2019 heating degree days in the United States were still 5.2 percent below normal (see Figure 3-7). Cooling degree days decreased by 5.4 percent compared to 2018, which reduced demand for air conditioning in the residential and commercial sector. Cooler summer conditions compared to 2018 impacted the amount of energy required for cooling, however, 2019 cooling degree days in the United States were still 22.2 percent above normal (see Figure 3-8) (EIA 2020c).¹⁰ The combination of slightly colder winter and cooler summer conditions led to overall residential and commercial energy consumption decreases of 0.2 and 3.5 percent, respectively relative to 2018.

⁹ See the sections entitled Stationary Combustion and Mobile Combustion in this chapter for information on non-CO₂ 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 3-7: Annual Deviations from Normal Heating Degree Days for the United States (1950–2019, Index Normal = 100)

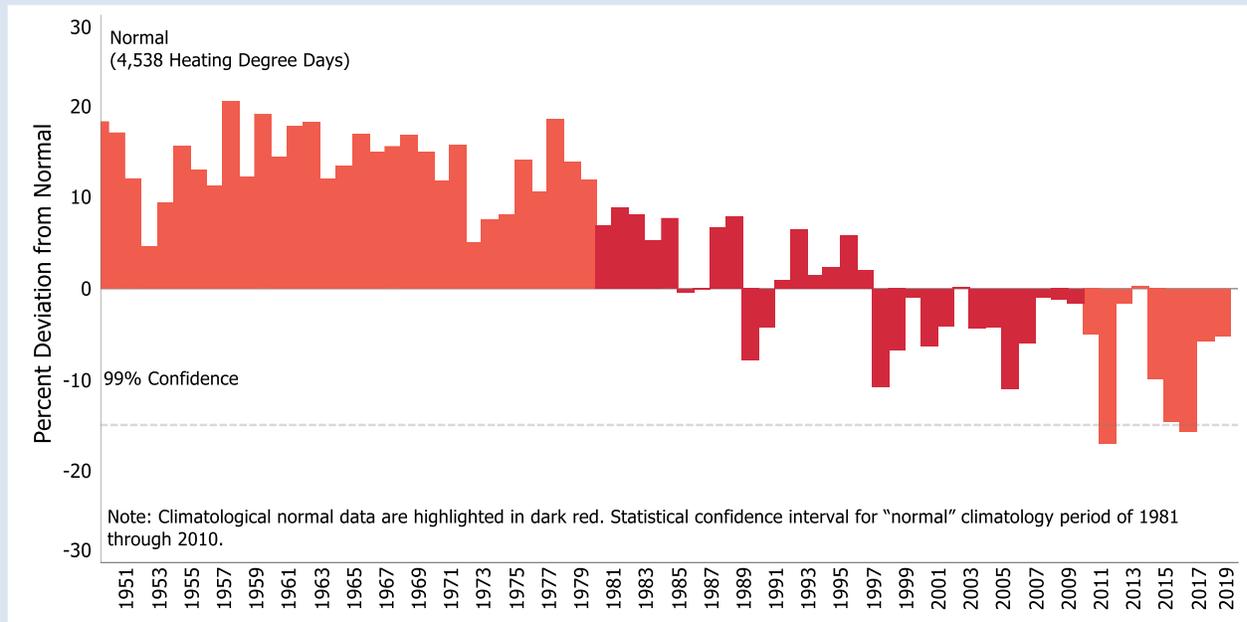
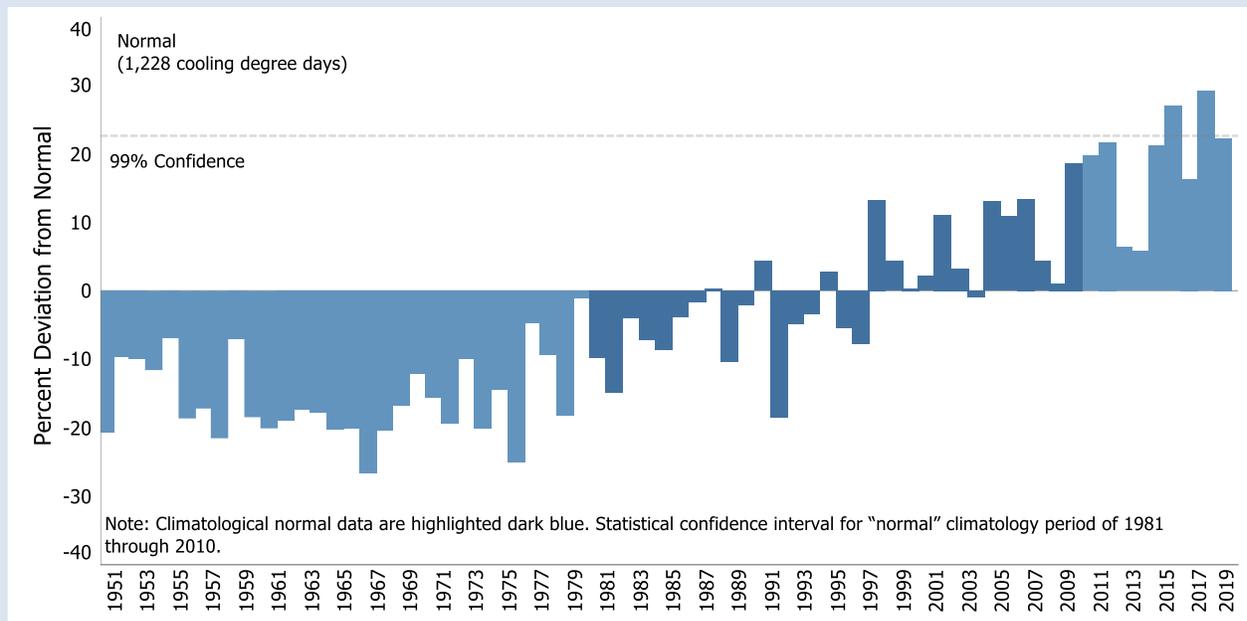


Figure 3-8: Annual Deviations from Normal Cooling Degree Days for the United States (1950–2019, Index Normal = 100)



1 The carbon intensity of the electric power sector is impacted by the amount of non-fossil energy sources of
 2 electricity. The utilization (i.e., capacity factors)¹¹ of nuclear power plants in 2019 remained high at 94 percent. In
 3 2019, nuclear power represented 20 percent of total electricity generation. Since 1990, the wind and solar power
 4 sectors have shown strong growth (between an observed minimum of 89 percent annual electricity generation
 5 growth to a maximum of 162 percent annual electricity generation growth), and have become relatively important
 6 electricity sources. Between 1990 and 2019, renewable energy generation (in kWh) from solar and wind energy
 7 have increased from 0.1 percent in 1990 to 9 percent in 2019 of total electricity generation, which helped drive the
 8 decrease in the carbon intensity of the electricity supply in the United States.

9 Fossil Fuel Combustion Emissions by Sector

10 In addition to the CO₂ emitted from fossil fuel combustion, CH₄ and N₂O are emitted from stationary and mobile
 11 combustion as well. Table 3-7 provides an overview of the CO₂, CH₄, and N₂O emissions from fossil fuel combustion
 12 by sector.

13 **Table 3-7: CO₂, CH₄, and N₂O Emissions from Fossil Fuel Combustion by Sector (MMT CO₂**
 14 **Eq.)**

End-Use Sector	1990	2005	2015	2016	2017	2018	2019
Transportation	1,520.7	1,914.6	1,775.0	1,820.9	1,835.3	1,842.8	1,864.1
CO ₂	1,469.1	1,868.8	1,750.5	1,797.3	1,812.6	1,821.2	1,843.2
CH ₄	6.4	3.9	2.6	2.5	2.5	2.4	2.4
N ₂ O	45.2	42.0	21.9	21.1	20.2	19.1	18.6
Electric Power	1,840.9	2,431.0	1,928.3	1,836.2	1,757.9	1,778.5	1,628.4
CO ₂	1,820.0	2,400.1	1,900.6	1,808.9	1,732.0	1,752.9	1,606.0
CH ₄	0.4	0.9	1.2	1.2	1.1	1.2	1.3
N ₂ O	20.5	30.1	26.5	26.2	24.8	24.4	21.1
Industrial	858.7	848.6	794.5	791.2	798.1	842.1	841.6
CO ₂	853.8	844.0	790.3	787.0	794.1	838.0	837.6
CH ₄	1.8	1.7	1.6	1.6	1.5	1.6	1.5
N ₂ O	3.1	2.9	2.6	2.6	2.5	2.5	2.5
Residential	344.9	364.0	323.4	297.0	299.2	345.0	344.4
CO ₂	338.6	359.1	318.1	292.3	294.6	339.5	338.8
CH ₄	5.2	4.1	4.5	3.9	3.8	4.5	4.6
N ₂ O	1.0	0.9	0.9	0.8	0.8	0.9	0.9
Commercial	229.8	227.4	226.3	211.8	213.7	248.4	239.8
CO ₂	228.3	226.0	224.9	210.4	212.3	246.9	238.3
CH ₄	1.1	1.1	1.1	1.1	1.1	1.2	1.2
N ₂ O	0.4	0.3	0.3	0.3	0.3	0.3	0.3
U.S. Territories^a	21.8	56.2	29.5	26.3	24.8	24.7	24.7
Total	4,816.7	5,841.9	5,077.1	4,983.4	4,929.0	5,081.5	4,942.9

Note: 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.

15 Other than CO₂, gases emitted from stationary combustion include the greenhouse gases CH₄ and N₂O and
 16 greenhouse gas precursors nitrogen oxides (NO_x), CO, and NMVOCs.¹² Methane and N₂O emissions from stationary

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 (2019).

¹² Sulfur dioxide (SO₂) emissions from stationary combustion are addressed in Annex 6.3.

1 combustion sources depend upon fuel characteristics, size and vintage of combustion device, along with
 2 combustion technology, pollution control equipment, ambient environmental conditions, and operation and
 3 maintenance practices. Nitrous oxide emissions from stationary combustion are closely related to air-fuel mixes
 4 and combustion temperatures, as well as the characteristics of any pollution control equipment that is employed.
 5 Methane emissions from stationary combustion are primarily a function of the CH₄ content of the fuel and
 6 combustion efficiency.

7 Mobile combustion also produces emissions of CH₄, N₂O, and greenhouse gas precursors including NO_x, CO, and
 8 NMVOCs. As with stationary combustion, N₂O and NO_x emissions from mobile combustion are closely related to
 9 fuel characteristics, air-fuel mixes, combustion temperatures, and the use of pollution control equipment. Nitrous
 10 oxide from mobile sources, in particular, can be formed by the catalytic processes used to control NO_x, CO, and
 11 hydrocarbon emissions. Carbon monoxide emissions from mobile combustion are significantly affected by
 12 combustion efficiency and the presence of post-combustion emission controls. Carbon monoxide emissions are
 13 highest when air-fuel mixtures have less oxygen than required for complete combustion. These emissions occur
 14 especially in vehicle idle, low speed, and cold start conditions. Methane and NMVOC emissions from motor
 15 vehicles are a function of the CH₄ content of the motor fuel, the amount of hydrocarbons passing uncombusted
 16 through the engine, and any post-combustion control of hydrocarbon emissions (such as catalytic converters).

17 An alternative method of presenting combustion emissions is to allocate emissions associated with electric power
 18 to the sectors in which it is used. Four end-use sectors are defined: transportation, industrial, residential, and
 19 commercial. In Table 3-8 below, electric power emissions have been distributed to each end-use sector based
 20 upon the sector's share of national electricity use, with the exception of CH₄ and N₂O from transportation
 21 electricity use.¹³ Emissions from U.S. Territories are also calculated separately due to a lack of end-use-specific
 22 consumption data.¹⁴ This method assumes that emissions from combustion sources are distributed across the four
 23 end-use sectors based on the ratio of electricity use in that sector. The results of this alternative method are
 24 presented in Table 3-8.

25 **Table 3-8: CO₂, CH₄, and N₂O Emissions from Fossil Fuel Combustion by End-Use Sector**
 26 **(MMT CO₂ Eq.)**

End-Use Sector	1990	2005	2015	2016	2017	2018	2019
Transportation	1,523.7	1,919.4	1,779.2	1,825.1	1,839.6	1,847.4	1,868.9
CO ₂	1,472.2	1,873.5	1,754.8	1,801.5	1,816.9	1,825.9	1,847.9
CH ₄	6.4	3.9	2.6	2.5	2.5	2.4	2.4
N ₂ O	45.2	42.0	21.9	21.1	20.2	19.1	18.6
Industrial	1,553.0	1,594.4	1,352.1	1,316.6	1,310.1	1,350.7	1,313.4
CO ₂	1,540.2	1,580.3	1,339.9	1,304.6	1,298.5	1,339.3	1,302.9
CH ₄	2.0	2.0	1.9	1.9	1.9	1.9	1.9
N ₂ O	10.8	12.1	10.3	10.1	9.7	9.5	8.6
Residential	944.4	1,231.1	1,017.2	960.4	925.5	996.5	936.0
CO ₂	931.3	1,215.1	1,001.9	945.8	911.7	981.7	922.3
CH ₄	5.4	4.4	4.9	4.3	4.2	5.0	5.1
N ₂ O	7.7	11.6	10.5	10.3	9.6	9.9	8.6
Commercial	773.7	1,040.8	899.0	855.1	829.0	862.1	799.9
CO ₂	766.0	1,029.0	887.9	844.0	818.5	851.7	790.7
CH ₄	1.2	1.4	1.5	1.5	1.5	1.6	1.6
N ₂ O	6.5	10.4	9.6	9.5	9.0	8.8	7.6
U.S. Territories^a	21.8	56.2	29.5	26.3	24.8	24.7	24.7
Total	4,816.7	5,841.9	5,077.1	4,983.4	4,929.0	5,081.5	4,942.9

¹³ Separate calculations are performed for transportation-related CH₄ and N₂O. The methodology used to calculate these emissions is 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.

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.

1 Stationary Combustion

2 The direct combustion of fuels by stationary sources in the electric power, industrial, commercial, and residential
3 sectors represent the greatest share of U.S. greenhouse gas emissions. Table 3-9 presents CO₂ emissions from
4 fossil fuel combustion by stationary sources. The CO₂ emitted is closely linked to the type of fuel being combusted
5 in each sector (see Methodology section of CO₂ from Fossil Fuel Combustion). Other than CO₂, gases emitted from
6 stationary combustion include the greenhouse gases CH₄ and N₂O. Table 3-10 and Table 3-11 present CH₄ and N₂O
7 emissions from the combustion of fuels in stationary sources. The CH₄ and N₂O emissions are estimated by
8 applying a “bottom-up” methodology that utilizes facility-specific technology and fuel use data reported to EPA’s
9 Acid Rain Program (EPA 2020a) (see Methodology section for CH₄ and N₂O from Stationary Combustion). Table 3-7
10 presents the corresponding direct CO₂, CH₄, and N₂O emissions from all sources of fuel combustion, without
11 allocating emissions from electricity use to the end-use sectors.

12 **Table 3-9: CO₂ Emissions from Stationary Fossil Fuel Combustion (MMT CO₂ Eq.)**

Sector/Fuel Type	1990	2005	2015	2016	2017	2018	2019
Electric Power	1,820.0	2,400.1	1,900.6	1,808.9	1,732.0	1,752.9	1,606.0
Coal	1,546.5	1,982.8	1,351.4	1,242.0	1,207.1	1,152.9	973.5
Natural Gas	175.4	318.9	525.2	545.0	505.6	577.4	616.0
Fuel Oil	97.5	98.0	23.7	21.5	18.9	22.2	16.2
Geothermal	0.5	0.5	0.4	0.4	0.4	0.4	0.4
Industrial	853.8	844.0	790.3	787.0	794.1	838.0	837.6
Coal	157.8	118.0	70.0	62.8	58.5	54.0	49.2
Natural Gas	408.8	388.6	464.4	474.5	485.3	515.1	524.3
Fuel Oil	287.2	337.3	255.9	249.7	250.3	269.0	264.0
Commercial	228.3	226.0	224.9	210.4	212.3	246.9	238.3
Coal	12.0	9.3	3.0	2.3	2.0	1.8	1.6
Natural Gas	142.0	162.9	175.4	170.5	173.2	192.5	192.8
Fuel Oil	74.3	53.8	46.5	37.6	37.1	52.6	43.9
Residential	338.6	359.1	318.1	292.3	294.6	339.5	338.8
Coal	3.0	0.8	NO	NO	NO	NO	NO
Natural Gas	237.8	262.2	252.7	238.4	241.5	273.8	275.3
Fuel Oil	97.8	96.1	65.4	54.0	53.2	65.7	63.5
U.S. Territories	21.7	56.0	29.4	26.2	24.7	24.6	24.6
Coal	0.5	3.0	4.1	3.2	2.5	2.5	2.5
Natural Gas	NO	1.3	3.0	3.4	2.5	2.5	2.5
Fuel Oil	21.2	51.7	22.2	19.6	19.7	19.5	19.5
Total	3,262.4	3,885.1	3,263.3	3,124.8	3,057.7	3,201.9	3,045.3

Note: Totals may not sum due to independent rounding.

NO (Not Occurring)

13 **Table 3-10: CH₄ Emissions from Stationary Combustion (MMT CO₂ Eq.)**

Sector/Fuel Type	1990	2005	2015	2016	2017	2018	2019
Electric Power	0.4	0.9	1.2	1.2	1.1	1.2	1.3
Coal	0.3	0.4	0.3	0.2	0.2	0.2	0.2
Fuel Oil	+	+	+	+	+	+	+
Natural gas	0.1	0.5	0.9	0.9	0.9	1.0	1.1
Wood	+	+	+	+	+	+	+
Industrial	1.8	1.7	1.6	1.6	1.5	1.6	1.5
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	0.1	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	1.0	1.0	1.0	1.0
Commercial	1.1	1.1	1.1	1.1	1.1	1.2	1.2
Coal	+	+	+	+	+	+	+
Fuel Oil	0.3	0.2	0.2	0.1	0.1	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	0.6	0.6	0.6	0.6	0.6
Residential	5.2	4.1	4.5	3.9	3.8	4.5	4.6
Coal	0.2	0.1	NO	NO	NO	NO	NO
Fuel Oil	0.3	0.3	0.2	0.2	0.2	0.2	0.2
Natural Gas	0.5	0.6	0.6	0.5	0.5	0.6	0.6
Wood	4.1	3.1	3.7	3.1	3.0	3.7	3.8
U.S. Territories	+	0.1	+	+	+	+	+
Coal	+	+	+	+	+	+	+
Fuel Oil	+	0.1	+	+	+	+	+
Natural Gas	NO	+	+	+	+	+	+
Wood	NO						
Total	8.6	7.8	8.4	7.8	7.6	8.6	8.6

Note: Totals may not sum due to independent rounding.

+ Does not exceed 0.05 MMT CO₂ Eq.

NO (Not Occurring)

1 **Table 3-11: N₂O Emissions from Stationary Combustion (MMT CO₂ Eq.)**

Sector/Fuel Type	1990	2005	2015	2016	2017	2018	2019
Electric Power	20.5	30.1	26.5	26.2	24.8	24.4	21.1
Coal	20.1	28.0	22.8	22.4	21.2	20.3	16.7
Fuel Oil	0.1	0.1	+	+	+	+	+
Natural Gas	0.3	1.9	3.7	3.8	3.6	4.1	4.4
Wood	+	+	+	+	+	+	+
Industrial	3.1	2.9	2.6	2.6	2.5	2.5	2.5
Coal	0.7	0.6	0.3	0.3	0.3	0.3	0.2
Fuel Oil	0.5	0.5	0.4	0.4	0.3	0.4	0.4
Natural Gas	0.2	0.2	0.2	0.3	0.3	0.3	0.3
Wood	1.6	1.6	1.7	1.7	1.6	1.6	1.6
Commercial	0.4	0.3	0.3	0.3	0.3	0.3	0.3
Coal	0.1	+	NO	NO	NO	NO	NO
Fuel Oil	0.2	0.1	0.1	0.1	0.1	0.1	0.1
Natural Gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wood	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Residential	1.0	0.9	0.9	0.8	0.8	0.9	0.9
Coal	+	+	0.0	0.0	0.0	0.0	0.0
Fuel Oil	0.2	0.2	0.2	0.1	0.1	0.2	0.2
Natural Gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wood	0.7	0.5	0.6	0.5	0.5	0.6	0.6
U.S. Territories	0.1						
Coal	+	+	+	+	+	+	+
Fuel Oil	0.1	0.1	0.1	+	+	+	+
Natural Gas	NO	+	+	+	+	+	+
Wood	NO						
Total	25.1	34.3	30.4	29.9	28.4	28.2	24.9

Note: Totals may not sum due to independent rounding.

+ Does not exceed 0.05 MMT CO₂ Eq.

NO (Not Occurring)

1 Electric Power Sector

2 The process of generating electricity is the largest stationary source of CO₂ emissions in the United States,
 3 representing 30.4 percent of total CO₂ emissions from all CO₂ emissions sources across the United States. Methane
 4 and N₂O accounted for a small portion of total greenhouse gas emissions from electric power, representing 0.1
 5 percent and 1.3 percent, respectively. Electric power also accounted for 32.9 percent of CO₂ emissions from fossil
 6 fuel combustion in 2019. Methane and N₂O from electric power represented 11.4 and 48.6 percent of total CH₄
 7 and N₂O emissions from fossil fuel combustion in 2019, respectively.

8 For the underlying energy data used in this chapter, the Energy Information Administration (EIA) places electric
 9 power generation into three functional categories: the electric power sector, the commercial sector, and the
 10 industrial sector. The electric power sector consists of electric utilities and independent power producers whose
 11 primary business is the production of electricity. This includes both regulated utilities and non-utilities (e.g.,
 12 independent power producers, qualifying co-generators, and other small power producers). Electric generation is
 13 reported as occurring in other sectors where the producer of the power indicates that its primary business is
 14 something other than the production of electricity.¹⁵

15 Total greenhouse gas emissions from the electric power sector have decreased by 11.5 percent since 1990. The
 16 carbon intensity of the electric power sector, in terms of CO₂ Eq. per Qbtu, has significantly decreased, by 16
 17 percent, during that same timeframe with the majority of the emissions and carbon intensity decreases occurring
 18 in the past decade. This decoupling of electric power generation and the resulting CO₂ emissions is shown in Figure
 19 3-9. This recent decarbonization of the electric power sector is a result of several key drivers. Coal-fired electric
 20 generation (in kilowatt-hours [kWh]) decreased from 54 percent of generation in 1990 to 24 percent in 2019.¹⁶ This
 21 corresponded with an increase in natural gas generation and renewable energy generation, largely from wind and
 22 solar energy. Natural gas generation (in kWh) represented 11 percent of electric power generation in 1990, and
 23 increased over the 30-year period to represent 37 percent of electric power sector generation in 2019 (see Table
 24 3-12). Natural gas has a much lower carbon content than coal, which has led to lower emissions as natural gas
 25 replaces coal-powered electricity generation. Natural gas and coal used in the U.S. in 2019 had an average carbon
 26 content of 14.43 MMT C/Qbtu and 26.08 MMT C/Qbtu respectively.

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

Fuel Type	1990	2005	2015	2016	2017	2018	2019
Coal	54.1%	51.1%	34.2%	31.4%	30.9%	28.4%	24.2%
Natural Gas	10.7%	17.5%	31.6%	32.7%	30.9%	34.0%	37.3%
Nuclear	19.9%	20.0%	20.4%	20.6%	20.8%	20.1%	20.4%
Renewables	11.3%	8.3%	13.0%	14.7%	16.8%	16.8%	17.6%
Petroleum	4.1%	3.0%	0.7%	0.6%	0.5%	0.6%	0.4%
Other Gases ^a	+	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
<i>Net Electricity Generation (Billion kWh)^b</i>	2,905	3,902	3,917	3,917	3,877	4,017	3,962

+ Does not exceed 0.05 percent.

^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.

28 In 2019, CO₂ emissions from the electric power sector decreased by 8.4 percent relative to 2018. This decrease in
 29 CO₂ emissions was primarily driven by a decrease in coal and petroleum consumed to produce electricity in the

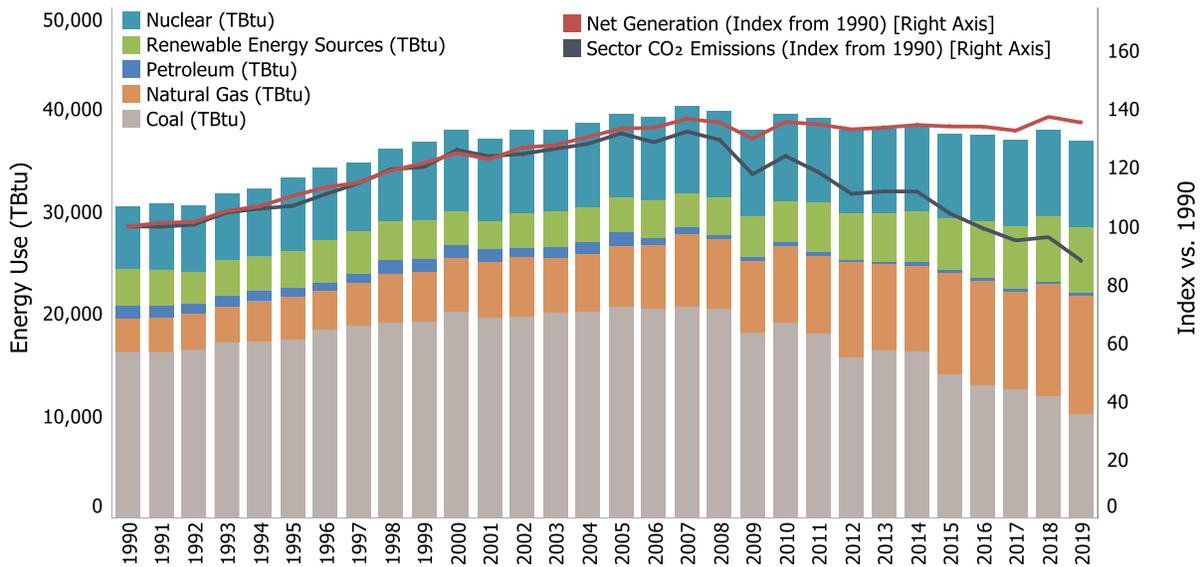
¹⁵ Utilities primarily generate power for the U.S. electric grid for sale to retail customers. Non-utilities typically generate electricity for sale on the wholesale electricity market (e.g., to utilities for distribution and resale to retail customers). Where electricity generation occurs outside the 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 2020c).

1 electric power sector as well as a decrease in electricity demand (1.2 percent reduction in retail sales).
 2 Consumption of coal for electric power decreased by 15.5 percent while consumption of natural gas increased 6.7
 3 percent from 2018 to 2019. There has also been a rapid increase in renewable energy electricity generation in the
 4 electric power sector in recent years. Electricity generation from renewable sources increased by 3 percent from
 5 2018 to 2019 (see Table 3-12). The decrease in coal-powered electricity generation and increase in natural gas and
 6 renewable energy electricity generation contributed to a decoupling of emissions trends from electric power
 7 generation trends over the recent time series (see Figure 3-9).

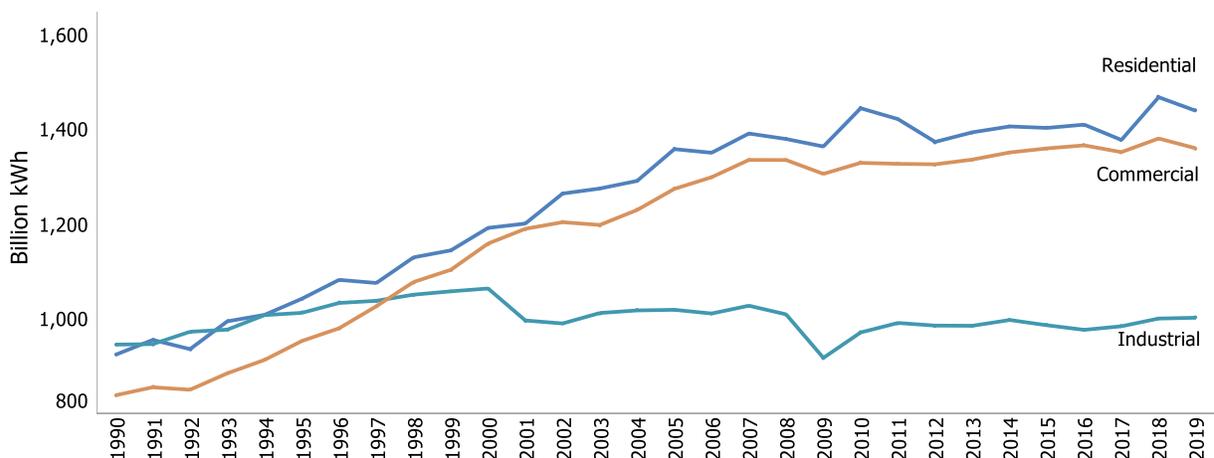
8 Decreases in natural gas prices and the associated increase in natural gas generation, particularly between 2005
 9 and 2019, was one of the main drivers of the recent fuel switching and decrease in electric power sector carbon
 10 intensity. During this time period, the cost of natural gas (in \$/MMBtu) decreased by 56 percent while the cost of
 11 coal (in \$/MMBtu) increased by 74 percent (EIA 2020c). Also, between 1990 and 2019, renewable energy
 12 generation (in kWh) from wind and solar energy increased from 0.1 percent of total generation in 1990 to 9
 13 percent in 2019, which also helped drive the decrease in electric power sector carbon intensity. This decrease in
 14 carbon intensity occurred even as total electricity retail sales increased 41 percent, from 2,713 billion kWh in 1990
 15 to 3,811 billion kWh in 2019.

16 **Figure 3-9: Fuels Used in Electric Power Generation and Total Electric Power Sector CO₂**
 17 **Emissions**



18
 19 Electricity was used primarily in the residential, commercial, and industrial end-use sectors for lighting, heating,
 20 electric motors, appliances, electronics, and air conditioning (see Figure 3-10). Note that transportation is an end-
 21 use sector as well but is not shown in Figure 3-10 due to the sector's relatively low percentage of electricity use.
 22 Table 3-13 provides a break-out of CO₂ emissions from electricity use in the transportation end-use sector.

1 **Figure 3-10: Electric Power Retail Sales by End-Use Sector**



2
 3 In 2019, electricity sales to the residential and commercial end-use sectors, as presented in Figure 3-10, decreased
 4 by 2.0 percent and 1.5 percent relative to 2018, respectively. Electricity sales to the industrial sector in 2019
 5 increased approximately 0.1 percent relative to 2018. The sections below describe end-use sector energy use in
 6 more detail. Overall, in 2019, the amount of electricity retail sales (in kWh) decreased by 1.2 percent relative to
 7 2018.

8 **Industrial Sector**

9 Industrial sector CO₂, CH₄, and N₂O, emissions accounted for 17, 14, and 6 percent of CO₂, CH₄, and N₂O, emissions
 10 from fossil fuel combustion, respectively in 2019. Carbon dioxide, CH₄, and N₂O emissions resulted from the direct
 11 consumption of fossil fuels for steam and process heat production.

12 The industrial end-use sector, per the underlying energy use data from EIA, includes activities such as
 13 manufacturing, construction, mining, and agriculture. The largest of these activities in terms of energy use is
 14 manufacturing, of which six industries—Petroleum Refineries, Chemicals, Paper, Primary Metals, Food, and
 15 Nonmetallic Mineral Products—represent the majority of the energy use (EIA 2020c; EIA 2009b).

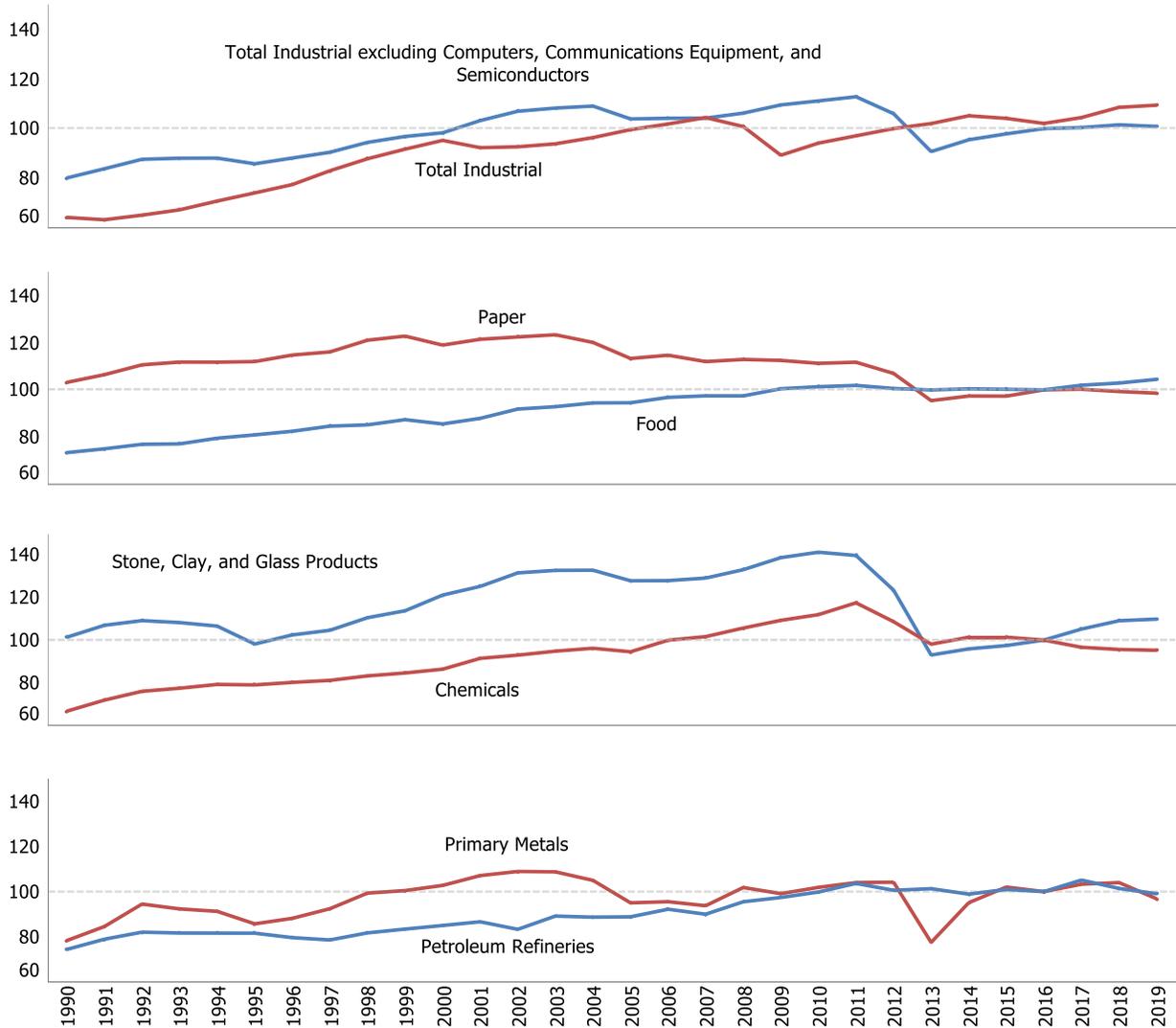
16 There are many dynamics that impact emissions from the industrial sector including economic activity, changes in
 17 the make-up of the industrial sector, changes in the emissions intensity of industrial processes, and weather-
 18 related impacts on heating and cooling of industrial buildings.¹⁷ Structural changes within the U.S. economy that
 19 lead to shifts in industrial output away from energy-intensive manufacturing products to less energy-intensive
 20 products (e.g., from steel to computer equipment) have had a significant effect on industrial emissions.

21 From 2018 to 2019, total industrial production and manufacturing output increased by 0.8 percent (FRB 2019).
 22 Over this period, output increased across production indices for Food, and Nonmetallic Mineral Products, and
 23 decreased slightly for Paper, Petroleum Refineries, Chemicals, and Primary Metals (see Figure 3-11). From 2018 to
 24 2019, total energy use in the industrial sector increased by 0.5 percent. Due to the relative increases and decreases
 25 of individual indices there was an increase in natural gas and a decrease in electricity used by the sector (see Figure
 26 3-11). In 2019, CO₂, CH₄, and N₂O emissions from fossil fuel combustion and electricity use within the industrial
 27 end-use sector totaled 1,313.4 MMT CO₂ Eq., a 2.8 percent decrease from 2018 emissions.

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.

1 Through EPA’s Greenhouse Gas Reporting Program (GHGRP), specific industrial sector trends can be discerned
 2 from the overall total EIA industrial fuel consumption data used for these calculations. For example, from 2017 to
 3 2018, the underlying EIA data showed decreased consumption of coal, and increase of natural gas in the industrial
 4 sector. The GHGRP data highlights that several industries contributed to these trends, including chemical
 5 manufacturing; pulp, paper and print; food processing, beverages and tobacco; minerals manufacturing; and
 6 agriculture-forest-fisheries.¹⁸

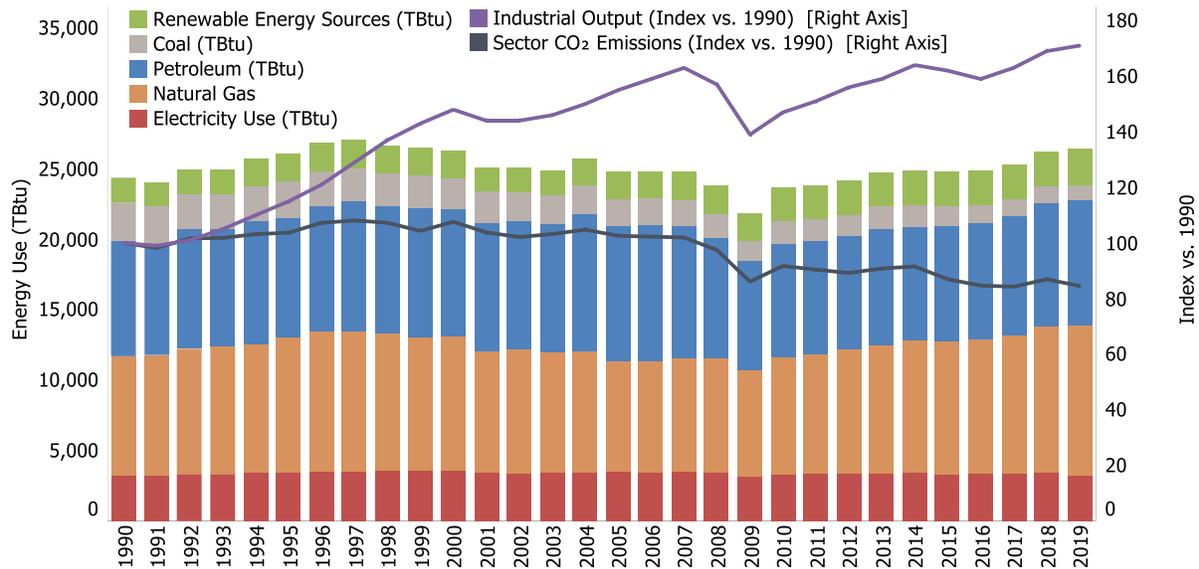
7 **Figure 3-11: Industrial Production Indices (Index 2012=100)**



8
 9
 10
 11

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

1 **Figure 3-12: Fuels and Electricity Used in Industrial Sector, Industrial Output, and Total**
 2 **Sector CO₂ Emissions (Including Electricity)**



3
 4 Despite the growth in industrial output (70 percent) and the overall U.S. economy (104 percent) from 1990 to
 5 2019, direct CO₂ emissions from fossil fuel combustion in the industrial sector decreased by 1.9 percent over the
 6 same time series (see Figure 3-12). A number of factors are assumed to result in decoupling of growth in industrial
 7 output from industrial greenhouse gas emissions, for example: (1) more rapid growth in output from less energy-
 8 intensive industries relative to traditional manufacturing industries, and (2) energy-intensive industries such as
 9 steel are employing new methods, such as electric arc furnaces, that are less carbon intensive than the older
 10 methods.

11 **Box 3-3: Uses of Greenhouse Gas Reporting Program Data and Improvements in Reporting Emissions from**
 12 **Industrial Sector Fossil Fuel Combustion – TO BE UPDATED FOR FINAL REPORT**

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

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>.

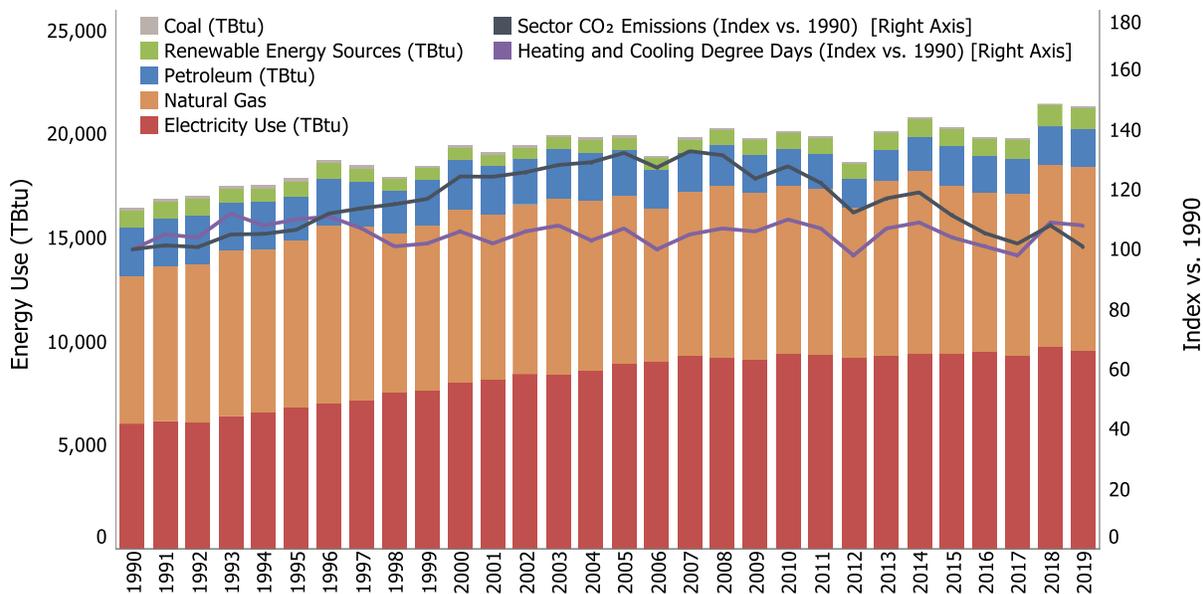
approach presented in this report. Consistent with recommendations for reporting the Inventory to the UNFCCC, progress was made on certain fuel types for specific industries and has been included in the CRF tables that are submitted to the UNFCCC along with this report.²⁰ The efforts in reconciling fuels 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.

1

2 Residential and Commercial Sectors

3 Emissions from the residential and commercial sectors have generally decreased since 1990. Short-term trends are
 4 often correlated with seasonal fluctuations in energy use caused by weather conditions, rather than prevailing
 5 economic conditions. Population growth and a trend towards larger houses has led to increasing energy use over
 6 the time series, while population migration to warmer areas and improved energy efficiency and building
 7 insulation have slowed the increase in energy use in recent years. Starting in around 2014, energy use and
 8 emissions begin to decouple due to decarbonization of the electric power sector (see Figure 3-13).

9 **Figure 3-13: Fuels and Electricity Used in Residential and Commercial Sectors, Heating and**
 10 **Cooling Degree Days, and Total Sector CO₂ Emissions (Including Electricity)**



11

12 In 2019 the residential and commercial sectors accounted for 7 and 5 percent of CO₂ emissions from fossil fuel
 13 combustion, respectively; 42 and 11 percent of CH₄ emissions from fossil fuel combustion, respectively; and 2 and

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

1 1 percent of N₂O emissions from fossil fuel combustion, respectively. Emissions from these sectors were largely
2 due to the direct consumption of natural gas and petroleum products, primarily for heating and cooking needs.
3 Coal consumption was a minor component of energy use in the commercial sector and did not contribute to any
4 energy use in the residential sector. In 2019, total emissions (CO₂, CH₄, and N₂O) from fossil fuel combustion and
5 electricity use within the residential and commercial end-use sectors were 936.0 MMT CO₂ Eq. and 799.9 MMT CO₂
6 Eq., respectively. Total CO₂, CH₄, and N₂O emissions from combined fossil fuel combustion and electricity use
7 within the residential and commercial end-use sectors decreased by 6.1 and 7.2 percent from 2018 to 2019,
8 respectively. A slight increase in heating degree days (0.6 percent) impacted energy demand for heating in the
9 residential and commercial sectors. This was partially offset by a 5.4 percent decrease in cooling degree days
10 compared to 2018, which reduced demand for air conditioning in the residential and commercial sectors. In
11 addition, a shift toward energy efficient products and more stringent energy efficiency standards for household
12 equipment has contributed to a decrease in energy demand in households (EIA 2020g), resulting in a decrease in
13 energy-related emissions. In the long term, the residential sector is also affected by population growth, migration
14 trends toward warmer areas, and changes in total housing units and building attributes (e.g., larger sizes and
15 improved insulation).

16 In 2019, combustion emissions from natural gas consumption represented 81 and 81 percent of the direct fossil
17 fuel CO₂ emissions from the residential and commercial sectors, respectively. Carbon dioxide emissions from
18 natural gas combustion in the residential and commercial sectors in 2019 increased by 0.5 percent and 0.1 percent
19 from 2018 to 2019, respectively.

20 **U.S. Territories**

21 Emissions from U.S. Territories are based on the fuel consumption in American Samoa, Guam, Puerto Rico, U.S.
22 Virgin Islands, Wake Island, and other U.S. Pacific Islands. As described in the Methodology section of CO₂ from
23 Fossil Fuel Combustion, this data is collected separately from the sectoral-level data available for the general
24 calculations. As sectoral information is not available for U.S. Territories, CO₂, CH₄, and N₂O emissions are not
25 presented for U.S. Territories in the tables above by sector, though the emissions will include some transportation
26 and mobile combustion sources.

27 **Transportation Sector and Mobile Combustion**

28 This discussion of transportation emissions follows the alternative method of presenting combustion emissions by
29 allocating emissions associated with electricity generation to the transportation end-use sector, as presented in
30 Table 3-8. Table 3-7 presents direct CO₂, CH₄, and N₂O emissions from all transportation sources (i.e., excluding
31 emissions allocated to electricity consumption in the transportation end-use sector).

32 The transportation end-use sector and other mobile combustion accounted for 1,868.9 MMT CO₂ Eq. in 2019,
33 which represented 36 percent of CO₂ emissions, 22 percent of CH₄ emissions, and 43 percent of N₂O emissions
34 from fossil fuel combustion, respectively.²¹ Fuel purchased in the United States for international aircraft and
35 marine travel accounted for an additional 117.2 MMT CO₂ Eq. in 2019; these emissions are recorded as
36 international bunkers and are not included in U.S. totals according to UNFCCC reporting protocols.

37 *Transportation End-Use Sector*

38 From 1990 to 2019, transportation emissions from fossil fuel combustion rose by 22 percent due, in large part, to
39 increased demand for travel (see Figure 3-14). The number of vehicle miles traveled (VMT) by light-duty motor

²¹ Note that these totals include CO₂, CH₄ and N₂O emissions from some sources in the U.S. Territories (ships and boats, recreational boats, non-transportation mobile sources) and CH₄ and N₂O emissions from transportation rail electricity.

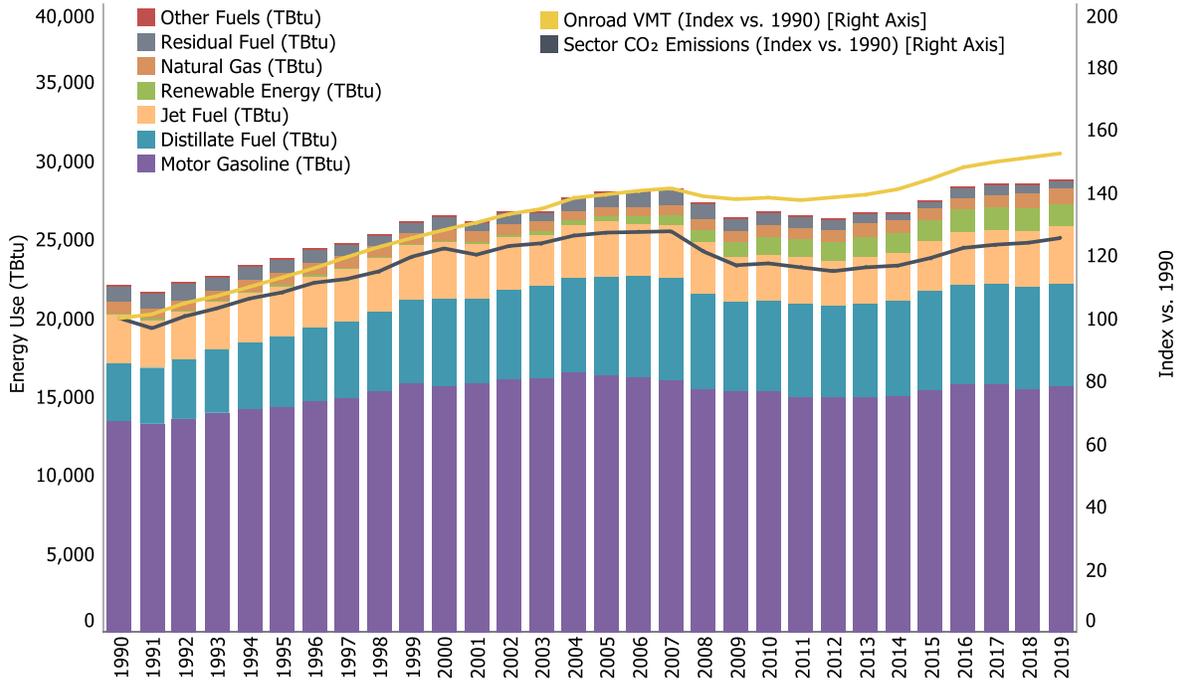
1 vehicles (passenger cars and light-duty trucks) increased 48 percent from 1990 to 2019,²² as a result of a
 2 confluence of factors including population growth, economic growth, urban sprawl, and periods of low fuel prices.

3 From 2018 to 2019, CO₂ emissions from the transportation end-use sector increased by 1.21 percent. The small
 4 increase in emissions is primarily attributed to an increase in non-road fuel use, particularly jet fuel consumption.

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

9 Almost all of the energy consumed for transportation was supplied by petroleum-based products, with more than
 10 half being related to gasoline consumption in automobiles and other highway vehicles. Other fuel uses, especially
 11 diesel fuel for freight trucks and jet fuel for aircraft, accounted for the remainder. The primary driver of
 12 transportation-related emissions was CO₂ from fossil fuel combustion, which increased by 26 percent from 1990 to
 13 2019. Annex 3.2 presents the total emissions from all transportation and mobile sources, including CO₂, N₂O, CH₄,
 14 and HFCs.

15 **Figure 3-14: Fuels Used in Transportation Sector, Onroad VMT, and Total Sector CO₂**
 16 **Emissions**



17 Notes: Distillate fuel, residual fuel, and jet fuel include adjustments for international bunker fuels. Distillate fuel and motor
 18 gasoline include adjustments for the sectoral allocation of these fuels. Other Fuels includes aviation gasoline and propane.
 19 Source: Information on fuel consumption was obtained from EIA (2019a).
 20

²² VMT estimates are based on data from FHWA Highway Statistics Table VM-1 (FHWA 1996 through 2019). Table VM-1 VMT data for 2019 has not been published yet, therefore 2019 VMT data is estimated using the traffic volume percent change from 2018 to 2019 using FHWA's Traffic Volume Trends. 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 2019 time period. In absence of these method changes, light-duty VMT growth between 1990 and 2019 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.

1 *Transportation Fossil Fuel Combustion CO₂ Emissions*

2 Domestic transportation CO₂ emissions increased by 26 percent (375.8 MMT CO₂) between 1990 and 2019, an
3 annualized increase of 0.9 percent. Among domestic transportation sources in 2019, light-duty vehicles (including
4 passenger cars and light-duty trucks) represented 58 percent of CO₂ emissions from fossil fuel combustion,
5 medium- and heavy-duty trucks and buses 25 percent, commercial aircraft 7 percent, and other sources 10
6 percent. See Table 3-13 for a detailed breakdown of transportation CO₂ emissions by mode and fuel type.

7 Almost all of the energy consumed by the transportation sector is petroleum-based, including motor gasoline,
8 diesel fuel, jet fuel, and residual oil. Carbon dioxide emissions from the combustion of ethanol and biodiesel for
9 transportation purposes, along with the emissions associated with the agricultural and industrial processes
10 involved in the production of biofuel, are captured in other Inventory sectors.²⁴ Ethanol consumption by the
11 transportation sector has increased from 0.7 billion gallons in 1990 to 13.8 billion gallons in 2019, while biodiesel
12 consumption has increased from 0.01 billion gallons in 2001 to 1.9 billion gallons in 2019. For additional
13 information, see Section 3.11 on biofuel consumption at the end of this chapter and Table A-83 in Annex 3.2.

14 Carbon dioxide emissions from passenger cars and light-duty trucks totaled 1,078.6 MMT CO₂ in 2019. This is an
15 increase of 17 percent (154.1 MMT CO₂) from 1990 due, in large part, to increased demand for travel as fleet-wide
16 light-duty vehicle fuel economy was relatively stable (average new vehicle fuel economy declined slowly from 1990
17 through 2004 and then increased more rapidly from 2005 through 2019). Carbon dioxide emissions from
18 passenger cars and light-duty trucks peaked at 1,164.1 MMT CO₂ in 2004, and since then have declined about 7
19 percent. The decline in new light-duty vehicle fuel economy between 1990 and 2004 (Figure 3-15) is reflected the
20 increasing market share of light-duty trucks, which grew from about 30 percent of new vehicle sales in 1990 to 48
21 percent in 2004. Starting in 2005, average new vehicle fuel economy began to increase while light-duty VMT grew
22 only modestly for much of the period. Light-duty vehicle VMT grew by less than one percent or declined each year
23 between 2005 and 2013,²⁵ then grew at a faster rate until 2016 (2.6 percent from 2014 to 2015, and 2.5 percent
24 from 2015 to 2016). Between 2016 and 2018, the rate of light-duty VMT growth slowed to less than one percent
25 each year, and was followed by an increase of roughly 1.4 percent in 2019. Average new vehicle fuel economy has
26 increased almost every year since 2005, while the light-duty truck share decreased to about 33 percent in 2009
27 and has since varied from year to year between 36 and 48 percent. Light-duty truck share is about 48 percent of
28 new vehicles in model year 2019 (EPA 2019b). See Annex 3.2 for data by vehicle mode and information on VMT
29 and the share of new vehicles (in VMT).

30 Medium- and heavy-duty truck CO₂ emissions increased by 89 percent from 1990 to 2019. This increase was largely
31 due to a substantial growth in medium- and heavy-duty truck VMT, which increased by 124 percent between 1990
32 and 2019.²⁶ Carbon dioxide from the domestic operation of commercial aircraft increased by 18 percent (19.7

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>>.

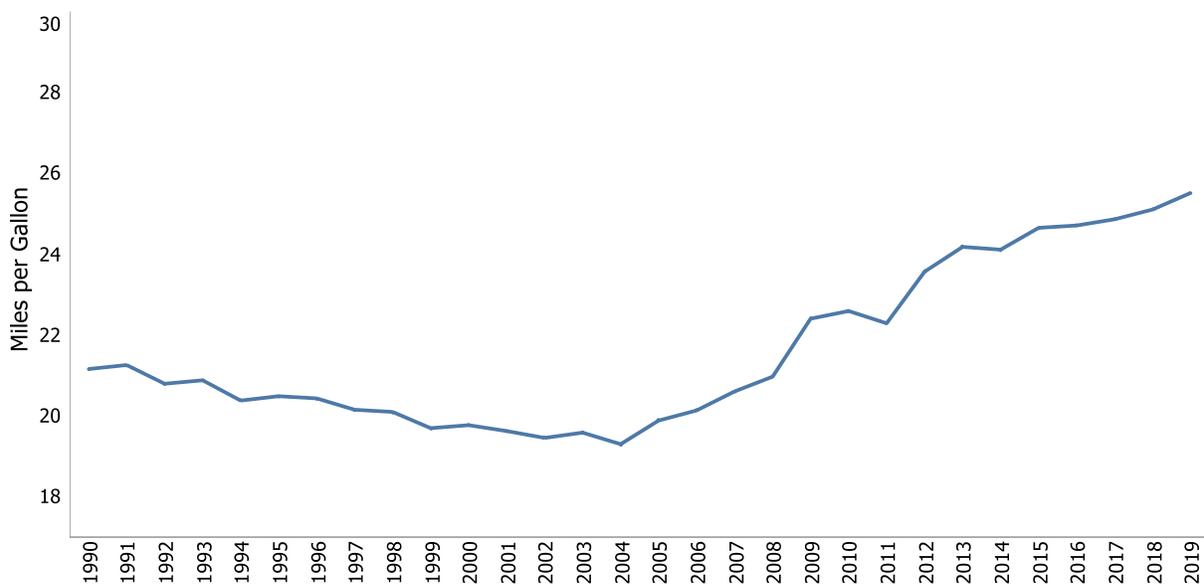
²⁵ VMT estimates are based on data from FHWA Highway Statistics Table VM-1 (FHWA 1996 through 2019). In 2007 and 2008 light-duty VMT decreased 3.0 percent and 2.3 percent, respectively. Note that the decline in light-duty VMT from 2006 to 2007 is due at least in part to a change in FHWA's methods for 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 2019 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 2019 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.

1 MMT CO₂) from 1990 to 2019.²⁷ Across all categories of aviation, excluding international bunkers, CO₂ emissions
2 decreased by 4 percent (8.0 MMT CO₂) between 1990 and 2019.²⁸ This includes a 66 percent (23.2 MMT CO₂)
3 decrease in CO₂ emissions from domestic military operations.

4 Transportation sources also produce CH₄ and N₂O; these emissions are included in Table 3-14 and Table 3-15 and
5 in the CH₄ and N₂O from Mobile Combustion section. Annex 3.2 presents total emissions from all transportation
6 and mobile sources, including CO₂, CH₄, N₂O, and HFCs.

7 **Figure 3-15: Sales-Weighted Fuel Economy of New Passenger Cars and Light-Duty Trucks,**
8 **1990–2019**

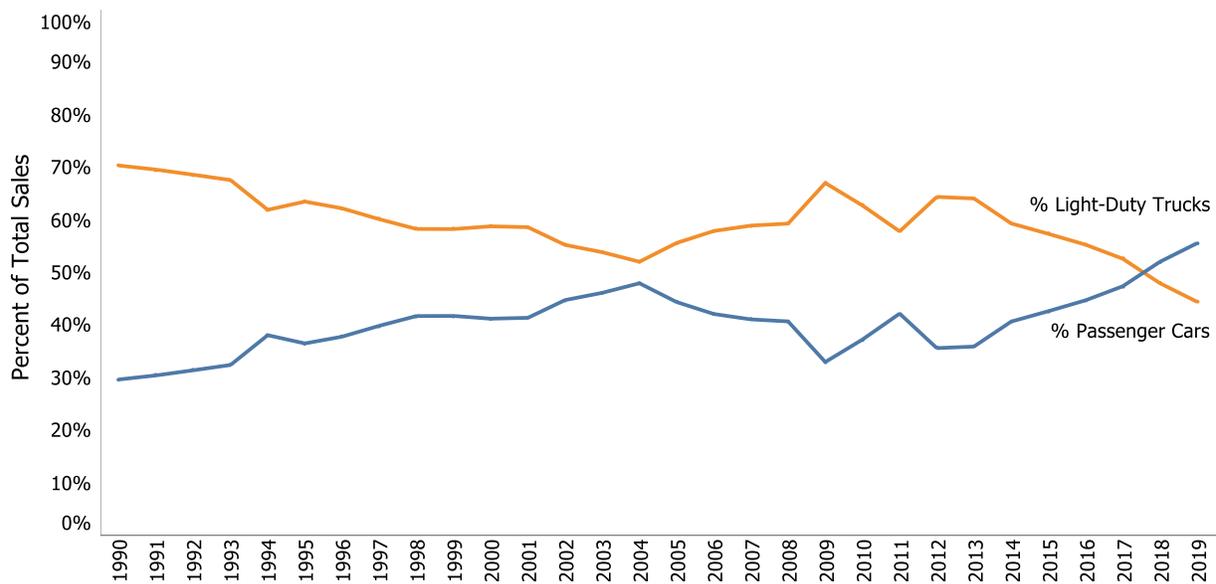


9 Source: EPA (2019a).
10
11

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.

1 **Figure 3-16: Sales of New Passenger Cars and Light-Duty Trucks, 1990–2019**



2
3 Source: EPA (2019b).

4 **Table 3-13: CO₂ Emissions from Fossil Fuel Combustion in Transportation End-Use Sector**
5 **(MMT CO₂ Eq.)**

Fuel/Vehicle Type	1990	2005	2015 ^a	2016 ^a	2017 ^a	2018 ^a	2019 ^a
Gasoline^b	958.9	1,160.8	1,092.8	1,120.2	1,117.6	1,107.7	1,116.7
Passenger Cars	604.3	643.0	747.6	761.8	761.8	756.0	762.2
Light-Duty Trucks	300.6	467.8	289.5	301.3	297.8	293.7	296.1
Medium- and Heavy-Duty Trucks ^c	37.7	34.1	40.2	41.3	42.2	42.3	42.7
Buses	0.3	0.4	0.9	0.9	1.0	1.0	1.0
Motorcycles	1.7	1.6	3.7	3.9	3.8	3.8	3.8
Recreational Boats ^d	14.3	13.9	10.8	10.9	11.0	10.8	10.8
Distillate Fuel Oil (Diesel)^b	274.6	471.5	454.6	456.2	462.7	474.2	477.1
Passenger Cars	7.9	4.3	4.2	4.3	4.3	4.3	4.4
Light-Duty Trucks	11.5	26.1	13.7	14.1	13.9	14.0	14.2
Medium- and Heavy-Duty Trucks ^c	190.5	363.8	364.5	370.9	377.0	385.9	390.7
Buses	8.0	10.7	16.9	16.7	17.7	19.0	19.3
Rail	35.5	46.0	39.5	36.4	37.1	38.9	36.7
Recreational Boats ^d	2.7	2.8	2.6	2.7	2.7	2.8	2.9
Ships and Non-Recreational Boats ^e	6.8	8.4	13.1	11.0	9.9	9.3	9.1
International Bunker Fuels ^f	11.7	9.4	8.3	8.6	8.9	9.9	10.0
Jet Fuel	184.2	189.3	157.6	166.0	171.8	172.3	177.7
Commercial Aircraft ^g	109.9	132.7	119.0	120.4	128.0	129.6	129.6
Military Aircraft	35.0	19.4	13.5	12.3	12.2	11.8	11.7
General Aviation Aircraft	39.4	37.3	25.1	33.4	31.5	30.9	36.4
International Bunker Fuels ^f	38.0	60.1	71.9	74.1	77.7	80.8	80.8
International Bunker Fuels from Commercial Aviation	30.0	55.6	68.6	70.8	74.5	77.7	77.7
Aviation Gasoline	3.1	2.4	1.5	1.4	1.4	1.5	1.6

General Aviation Aircraft	3.1	2.4	1.5	1.4	1.4	1.5	1.6
Residual Fuel Oil	22.6	19.3	4.2	12.9	16.5	14.0	14.7
Ships and Boats ^e	22.6	19.3	4.2	12.9	16.5	14.0	14.7
<i>International Bunker Fuels^f</i>	<i>53.7</i>	<i>43.6</i>	<i>30.6</i>	<i>33.8</i>	<i>33.4</i>	<i>31.4</i>	<i>25.2</i>
Natural Gas^g	36.0	33.1	39.4	40.1	42.3	50.9	54.8
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+
Medium- and Heavy-Duty Trucks	+	+	+	+	+	+	+
Buses	+	0.6	0.9	0.8	0.9	0.9	1.0
Pipeline ^h	36.0	32.4	38.5	39.2	41.3	49.9	53.7
LPGⁱ	1.4	1.8	0.4	0.4	0.4	0.5	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	0.0	0.1	0.1	0.1	0.1
Electricity^l	3.0	4.7	4.3	4.2	4.3	4.7	4.7
Passenger Cars	+	+	0.5	0.6	0.8	1.2	1.4
Light-Duty Trucks	+	+	+	0.1	0.1	0.2	0.2
Buses	+	+	+	+	+	+	+
Rail	3.0	4.7	3.7	3.5	3.4	3.3	3.1
Total^k	1,472.2	1,873.5	1,754.8	1,801.5	1,816.9	1,825.9	1,847.9
Total (Including Bunkers)^f	1,575.6	1,986.7	1,865.6	1,918.0	1,937.0	1,947.9	1,964.0
<i>Biofuels-Ethanol^l</i>	<i>4.1</i>	<i>21.8</i>	<i>76.6</i>	<i>79.4</i>	<i>80.2</i>	<i>78.6</i>	<i>80.2</i>
<i>Biofuels-Biodiesel^l</i>	<i>+</i>	<i>0.9</i>	<i>14.1</i>	<i>19.6</i>	<i>18.7</i>	<i>17.9</i>	<i>17.1</i>

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 CO₂ 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 CO₂ 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 2098 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 2019). Table VM-1 fuel consumption data for 2019 has not been published yet, therefore 2019 fuel consumption data is estimated using the traffic volume percent change from 2018 to 2019 using FHWA's Traffic Volume Trends. 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 2018). TEDB data for 2019 has not been published yet, therefore 2018 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 2019.

^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 CO₂ 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 2019 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, CO₂ 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 2019 time period.

1

2 *Mobile Fossil Fuel Combustion CH₄ and N₂O Emissions*

3 Mobile combustion includes emissions of CH₄ and N₂O from all transportation sources identified in the U.S.
4 Inventory with the exception of pipelines and electric locomotives;²⁹ mobile sources also include non-
5 transportation sources such as construction/mining equipment, agricultural equipment, vehicles used off-road,
6 and other sources (e.g., snowmobiles, lawnmowers, etc.).³⁰ Annex 3.2 includes a summary of all emissions from
7 both transportation and mobile sources. Table 3-14 and Table 3-15 provide mobile fossil fuel CH₄ and N₂O emission
8 estimates in MMT CO₂ Eq.³¹

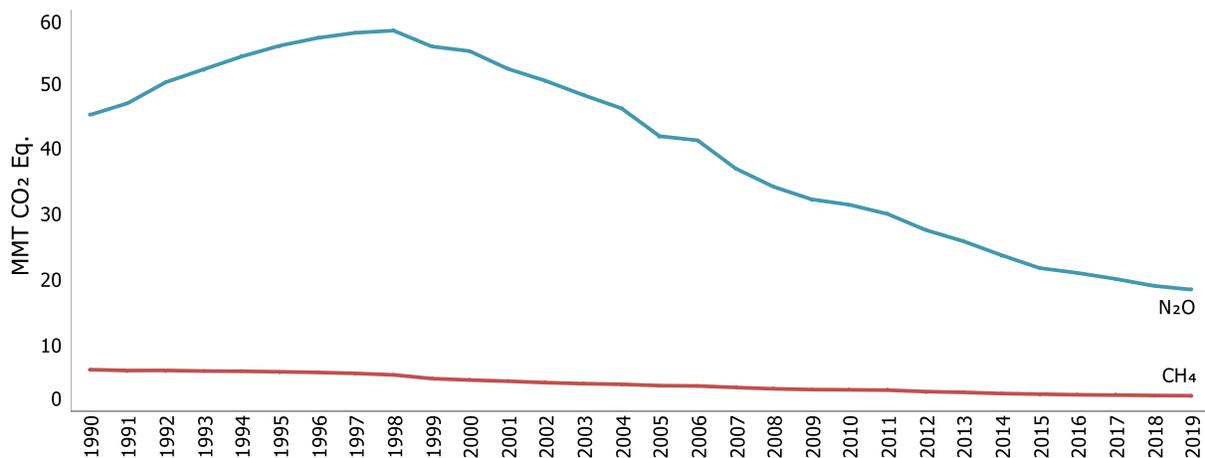
9 Mobile combustion was responsible for a small portion of national CH₄ emissions (0.4 percent) and was the fifth
10 largest source of national N₂O emissions (4.1 percent). From 1990 to 2019, mobile source CH₄ emissions declined
11 by 62 percent, to 2.4 MMT CO₂ Eq. (95 kt CH₄), due largely to emissions control technologies employed in on-road
12 vehicles since the mid-1990s to reduce CO, NO_x, NMVOC, and CH₄ emissions. Mobile source emissions of N₂O
13 decreased by 59 percent from 1990 to 2019, to 18.6 MMT CO₂ Eq. (61 kt N₂O). Earlier generation emissions control
14 technologies initially resulted in higher N₂O emissions, causing a 28 percent increase in N₂O emissions from mobile
15 sources between 1990 and 1997. Improvements in later-generation emissions control technologies have reduced
16 N₂O emissions, resulting in a 68 percent decrease in mobile source N₂O emissions from 1997 to 2019 (Figure 3-17).
17 Overall, CH₄ and N₂O emissions were predominantly from gasoline-fueled passenger cars and light-duty trucks and
18 non-highway sources. See Annex 3.2 for data by vehicle mode and information on VMT and the share of new
19 vehicles (in VMT).

²⁹ Emissions of CH₄ 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 CO₂ from Fossil Fuel Combustion and CH₄ and N₂O from Mobile Combustion sections of this chapter. Note that N₂O and CH₄ emissions are reported using different categories than CO₂. CO₂ emissions are reported by end-use sector (Transportation, Industrial, Commercial, Residential, U.S. Territories), and generally adhere to a top-down approach to estimating emissions. CO₂ 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 CO₂ emissions are included in the Industrial end-use sector instead of the Transportation end-use sector). CH₄ and N₂O emissions are reported using the "Mobile Combustion" category, which includes non-transportation mobile sources. CH₄ and N₂O 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, CO₂ 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 2019.

1 **Figure 3-17: Mobile Source CH₄ and N₂O Emissions**



2

3 **Table 3-14: CH₄ Emissions from Mobile Combustion (MMT CO₂ Eq.)**

Fuel Type/Vehicle Type ^a	1990	2005	2015	2016	2017	2018	2019
Gasoline On-Road^b	5.2	2.2	1.0	0.9	0.8	0.7	0.7
Passenger Cars	3.2	1.3	0.6	0.6	0.5	0.5	0.4
Light-Duty Trucks	1.7	0.8	0.2	0.2	0.2	0.2	0.2
Medium- and Heavy-Duty Trucks and Buses	0.3	0.1	0.1	0.0	0.0	0.0	0.0
Motorcycles	+	+	+	+	+	+	+
Diesel On-Road^b	+	+	0.1	0.1	0.1	0.1	0.1
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+
Medium- and Heavy-Duty Trucks and Buses	+	+	+	0.1	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	1.1	1.5	1.4	1.4	1.4	1.4	1.4
Ships and Boats	0.3	0.4	0.4	0.4	0.4	0.4	0.4
Rail	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Aircraft	0.1	0.1	+	+	+	+	+
Agricultural Equipment ^d	0.1	0.2	0.1	0.1	0.1	0.1	0.1
Construction/Mining Equipment ^e	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Other ^f	0.4	0.6	0.6	0.6	0.6	0.6	0.6
Total	6.4	3.9	2.6	2.5	2.5	2.4	2.4

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 2019 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 CO₂ 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. Table VM-1 fuel consumption data for 2019 has not been published yet, therefore 2019 fuel consumption data is estimated using the traffic volume percent change from 2018 to 2019 using FHWA's Traffic Volume Trends.

^c Rail emissions do not include emissions from electric powered locomotives. Class II and Class III diesel consumption data for 2014 to 2017 is estimated by applying the historical average fuel usage per carload factor to the annual number of carloads.

^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.

1 **Table 3-15: N₂O Emissions from Mobile Combustion (MMT CO₂ Eq.)**

Fuel Type/Vehicle Type ^a	1990	2005	2015	2016	2017	2018	2019
Gasoline On-Road^b	37.5	31.8	11.6	10.2	8.7	7.3	6.2
Passenger Cars	24.1	17.3	8.0	7.0	6.0	5.1	4.3
Light-Duty Trucks	12.8	13.6	3.1	2.7	2.3	1.9	1.6
Medium- and Heavy-Duty Trucks and Buses	0.5	0.9	0.4	0.4	0.3	0.3	0.2
Motorcycles	+	+	+	+	+	+	+
Diesel On-Road^b	0.2	0.3	2.1	2.4	2.6	2.8	3.2
Passenger Cars	+	+	+	0.1	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	2.0	2.2	2.5	2.7	3.0
Alternative Fuel On-Road	+	+	0.1	0.2	0.2	0.2	0.2
Non-Road	7.6	9.9	8.1	8.5	8.8	8.9	9.1
Ships and Boats	0.8	0.7	0.3	0.5	0.6	0.5	0.6
Rail ^c	0.3	0.4	0.4	0.3	0.4	0.4	0.3
Aircraft	1.7	1.8	1.5	1.5	1.6	1.6	1.6
Agricultural Equipment ^d	1.3	1.6	1.1	1.1	1.1	1.1	1.1
Construction/Mining Equipment ^e	1.3	2.1	1.5	1.6	1.7	1.8	1.9
Other ^f	2.2	3.3	3.3	3.4	3.4	3.5	3.6
Total	45.2	42.0	21.9	21.2	20.3	19.2	18.6

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 2019 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 CO₂ 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. Table VM-1 fuel consumption data for 2019 has not been published yet, therefore 2019 fuel consumption data is estimated using the traffic volume percent change from 2018 to 2019 using FHWA's Traffic Volume Trends.

^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.

^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.

CO₂ from Fossil Fuel Combustion

Methodology

CO₂ 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 2020c). EIA data include 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 2020e).³³

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

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 24.6 MMT CO₂ Eq. in 2019.

³⁴ See IPCC Reference Approach for Estimating CO₂ 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.

1 through 2017a), USGS (2014 through 2020a), USGS (1991 through 2015b), USGS (2020b), USGS (1991
2 through 2017).³⁶

3 3. *Adjust for biofuels and petroleum denaturant.* Fossil fuel consumption estimates are adjusted downward
4 to exclude fuels with biogenic origins and avoid double counting in petroleum data statistics. Carbon
5 dioxide emissions from ethanol added to motor gasoline and biodiesel added to diesel fuel are not
6 included specifically in summing energy sector totals. Net carbon fluxes from changes in biogenic carbon
7 reservoirs are accounted for in the estimates for LULUCF, therefore, fuel consumption estimates are
8 adjusted to remove ethanol and biodiesel.³⁷ For the years 1993 through 2008, petroleum denaturant is
9 currently included in EIA statistics for both natural gasoline and finished motor gasoline. To avoid double
10 counting, petroleum denaturant is subtracted from finished motor gasoline for these years.³⁸

11 4. *Adjust for exports of CO₂.* Since October 2000, the Dakota Gasification Plant has been exporting CO₂
12 produced in the coal gasification process to Canada by pipeline. Because this CO₂ is not emitted to the
13 atmosphere in the United States, the associated fossil fuel (lignite coal) that is gasified to create the
14 exported CO₂ is subtracted from EIA (2020d) coal consumption statistics that are used to calculate
15 greenhouse gas emissions from the Energy Sector. The associated fossil fuel is the total fossil fuel burned
16 at the plant with the CO₂ capture system multiplied by the fraction of the plant's total site-generated CO₂
17 that is recovered by the capture system. To make these adjustments, data for CO₂ exports were collected
18 from Environment and Climate Change Canada (2020). A discussion of the methodology used to estimate
19 the amount of CO₂ captured and exported by pipeline is presented in Annex 2.1.

20 5. *Adjust sectoral allocation of distillate fuel oil and motor gasoline.* EPA conducted a separate bottom-up
21 analysis of transportation fuel consumption based on data from the Federal Highway Administration that
22 indicated that the amount of distillate and motor gasoline consumption allocated to the transportation
23 sector in the EIA statistics should be adjusted. Therefore, for these estimates, the transportation sector's
24 distillate fuel and motor gasoline consumption were adjusted to match the value obtained from the
25 bottom-up analysis. As the total distillate and motor gasoline consumption estimate from EIA are
26 considered to be accurate at the national level, the distillate and motor gasoline consumption totals for
27 the residential, commercial, and industrial sectors were adjusted proportionately.³⁹ The data sources
28 used in the bottom-up analysis of transportation fuel consumption include AAR (2008 through 2018),
29 Benson (2002 through 2004), DOE (1993 through 2017), EIA (2007), EIA (1991 through 2019), EPA (2018),
30 and FHWA (1996 through 2018).⁴⁰

31 6. *Adjust for fuels consumed for non-energy uses.* U.S. aggregate energy statistics include consumption of
32 fossil fuels for non-energy purposes. These are fossil fuels that are manufactured into plastics, asphalt,
33 lubricants, or other products. Depending on the end-use, this can result in storage of some or all of the C
34 contained in the fuel for a period of time. As the emission pathways of C used for non-energy purposes
35 are vastly different than fuel combustion (since the C in these fuels ends up in products instead of being
36 combusted), these emissions are estimated separately in Section 3.2 – Carbon Emitted and Stored in
37 Products from Non-Energy Uses of Fossil Fuels. Therefore, the amount of fuels used for non-energy

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 (2020g) are already adjusted downward to account for biogas in natural gas.

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

³⁹ For 2014, 2018, and 2019, sectoral allocations of motor gasoline were proxied to previous years to correct for inconsistencies in the bottom-up analysis due to revised motor gasoline heat contents and C contents implemented for Public Review.

⁴⁰ 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 2019).

1 purposes was subtracted from total fuel consumption. Data on non-fuel consumption were provided by
2 EIA (2020c).

- 3 7. *Subtract consumption of international bunker fuels.* According to the UNFCCC reporting guidelines
4 emissions from international transport activities, or bunker fuels, should not be included in national
5 totals. U.S. energy consumption statistics include these bunker fuels (e.g., distillate fuel oil, residual fuel
6 oil, and jet fuel) as part of consumption by the transportation end-use sector, however, so emissions from
7 international transport activities were calculated separately following the same procedures used to
8 calculate emissions from consumption of all fossil fuels (i.e., estimation of consumption, and
9 determination of Carbon content).⁴¹ The Office of the Under Secretary of Defense (Installations and
10 Environment) and the Defense Logistics Agency Energy (DLA Energy) of the U.S. Department of Defense
11 (DoD) (DLA Energy 2020) supplied data on military jet fuel and marine fuel use. Commercial jet fuel use
12 was obtained from FAA (2019); residual and distillate fuel use for civilian marine bunkers was obtained
13 from DOC (1991 through 2019) for 1990 through 2001 and 2007 through 2018, and DHS (2008) for 2003
14 through 2006.⁴² Consumption of these fuels was subtracted from the corresponding fuels totals in the
15 transportation end-use sector. Estimates of international bunker fuel emissions for the United States are
16 discussed in detail in Section 3.10 – International Bunker Fuels.
- 17 8. *Determine the total Carbon content of fuels consumed.* Total C was estimated by multiplying the amount
18 of fuel consumed by the amount of C in each fuel. This total C estimate defines the maximum amount of C
19 that could potentially be released to the atmosphere if all of the C in each fuel was converted to CO₂. The
20 Carbon content coefficients used by the United States were obtained from EIA's *Emissions of Greenhouse
21 Gases in the United States 2008* (EIA 2009a), and an EPA analysis of Carbon content coefficients
22 developed for the GHGRP (EPA 2010). A discussion of the methodology used to develop the Carbon
23 content coefficients are presented in Annexes 2.1 and 2.2.
- 24 9. *Estimate CO₂ Emissions.* Total CO₂ emissions are the product of the adjusted energy consumption (from
25 the previous methodology steps 1 through 6), the Carbon content of the fuels consumed, and the fraction
26 of C that is oxidized. The fraction oxidized was assumed to be 100 percent for petroleum, coal, and
27 natural gas based on guidance in IPCC (2006) (see Annex 2.1). Carbon emissions were multiplied by the
28 molecular-to-atomic weight ratio of CO₂ to C (44/12) to obtain total CO₂ emitted from fossil fuel
29 combustion in million metric tons (MMT).
- 30 10. *Allocate transportation emissions by vehicle type.* This report provides a more detailed accounting of
31 emissions from transportation because it is such a large consumer of fossil fuels in the United States. For
32 fuel types other than jet fuel, fuel consumption data by vehicle type and transportation mode were used
33 to allocate emissions by fuel type calculated for the transportation end-use sector. Heat contents and
34 densities were obtained from EIA (2020c) and USAF (1998).⁴³
 - 35 • For on-road vehicles, annual estimates of combined motor gasoline and diesel fuel consumption by
36 vehicle category were obtained from FHWA (1996 through 2018); for each vehicle category, the

⁴¹ See International Bunker Fuels section in this chapter for a more detailed discussion.

⁴² Data for 2002 were interpolated due to inconsistencies in reported fuel consumption data.

⁴³ For a more detailed description of the data sources used for the analysis of the transportation end use sector see the Mobile Combustion (excluding CO₂) and International Bunker Fuels sections of the Energy chapter, Annex 3.2, and Annex 3.8, respectively.

- 1 percent gasoline, diesel, and other (e.g., CNG, LPG) fuel consumption are estimated using data from
2 DOE (1993 through 2018).^{44,45}
- 3 • For non-road vehicles, activity data were obtained from AAR (2008 through 2019), APTA (2007
4 through 2018), APTA (2006), BEA (2020), Benson (2002 through 2004), DLA Energy (2019), DOC (1991
5 through 2019), DOE (1993 through 2017), DOT (1991 through 2019), EIA (2009a), EIA (2020c), EIA
6 (2019f), EIA (1991 through 2019), EPA (2018),⁴⁶ and Gaffney (2007).
 - 7 • For jet fuel used by aircraft, CO₂ emissions from commercial aircraft were developed by the U.S.
8 Federal Aviation Administration (FAA) using a Tier 3B methodology, consistent IPCC (2006) (see
9 Annex 3.3). Carbon dioxide emissions from other aircraft were calculated directly based on reported
10 consumption of fuel as reported by EIA. Allocation to domestic military uses was made using DoD
11 data (see Annex 3.8). General aviation jet fuel consumption is calculated as the remainder of total jet
12 fuel use (as determined by EIA) nets all other jet fuel use as determined by FAA and DoD. For more
13 information, see Annex 3.2.

14 **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 CO₂ Eq./QBTu for natural gas to upwards of 95 MMT CO₂ 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

⁴⁴ 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 2019. 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.

⁴⁵ Transportation sector natural gas and LPG consumption are based on data from EIA (2020g). 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.

⁴⁶ In 2014, EPA incorporated the NONROAD2008 model into MOVES2014. The current Inventory uses the NONROAD component of MOVES2014b for years 1999 through 2018.

jet fuel, both around 70 MMT CO₂ 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 CO₂ Eq./Qbtu)

Sector	1990	2005	2015	2016	2017	2018	2019
Residential ^a	57.4	56.8	55.5	55.2	55.1	55.3	55.2
Commercial ^a	59.7	57.7	56.1	55.6	55.5	56.1	55.6
Industrial ^a	64.5	64.6	61.2	60.7	60.5	60.3	60.0
Transportation ^a	71.1	71.5	71.1	71.1	71.1	71.5	71.4
Electric Power ^b	87.3	85.8	78.1	76.8	77.3	75.5	73.0
U.S. Territories ^c	72.3	72.6	72.0	70.9	71.3	71.5	71.5
All Sectors^c	73.1	73.6	69.6	69.1	69.1	68.4	67.4

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

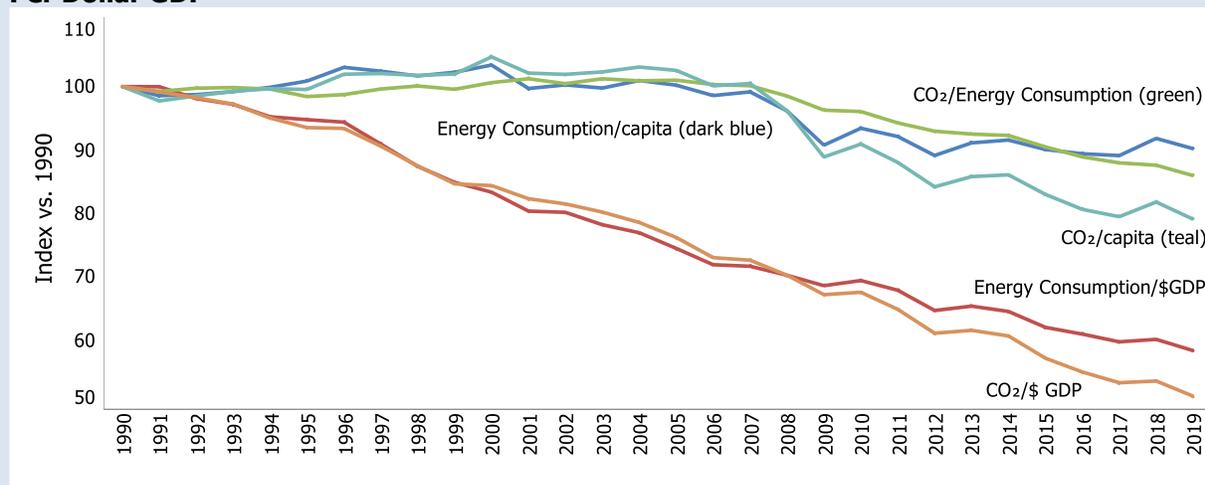
^a Does not include electricity or renewable energy consumption.

^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 2019, was approximately 9.8 percent below levels in 1990 (see Figure 3-18). To differentiate these estimates from those of Table 3-16, the carbon intensity trend shown in Figure 3-18 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 CO₂ emissions per dollar of gross domestic product (GDP) have both declined since 1990 (BEA 2018).

Figure 3-18: U.S. Energy Consumption and Energy-Related CO₂ Emissions Per Capita and Per Dollar GDP



Carbon intensity estimates were developed using nuclear and renewable energy data from EIA (2020c), EPA (2010), and fossil fuel consumption data as discussed above and presented in Annex 2.1.

1 **Uncertainty and Time-Series Consistency**

2 For estimates of CO₂ from fossil fuel combustion, the amount of CO₂ emitted is directly related to the amount of
3 fuel consumed, the fraction of the fuel that is oxidized, and the carbon content of the fuel. Therefore, a careful
4 accounting of fossil fuel consumption by fuel type, average carbon contents of fossil fuels consumed, and
5 production of fossil fuel-based products with long-term carbon storage should yield an accurate estimate of CO₂
6 emissions.

7 Nevertheless, there are uncertainties in the consumption data, carbon content of fuels and products, and carbon
8 oxidation efficiencies. For example, given the same primary fuel type (e.g., coal, petroleum, or natural gas), the
9 amount of carbon contained in the fuel per unit of useful energy can vary. For the United States, however, the
10 impact of these uncertainties on overall CO₂ emission estimates is believed to be relatively small. See, for example,
11 Marland and Pippin (1990). See also Annex 2.2 for a discussion of uncertainties associated with fuel carbon
12 contents. Even with recent updates to carbon factors for natural gas and coal, the uncertainty estimates are not
13 impacted.

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

21 To calculate the total CO₂ emission estimate from energy-related fossil fuel combustion, the amount of fuel used in
22 non-energy production processes were subtracted from the total fossil fuel consumption. The amount of CO₂
23 emissions resulting from non-energy related fossil fuel use has been calculated separately and reported in the
24 Carbon Emitted from Non-Energy Uses of Fossil Fuels section of this report (Section 3.2). These factors all
25 contribute to the uncertainty in the CO₂ estimates. Detailed discussions on the uncertainties associated with C
26 emitted from Non-Energy Uses of Fossil Fuels can be found within that section of this chapter.

27 Various sources of uncertainty surround the estimation of emissions from international bunker fuels, which are
28 subtracted from the U.S. totals (see the detailed discussions on these uncertainties provided in Section 3.10 –
29 International Bunker Fuels). Another source of uncertainty is fuel consumption by U.S. Territories. The United
30 States does not collect energy statistics for its territories at the same level of detail as for the fifty states and the
31 District of Columbia. Therefore, estimating both emissions and bunker fuel consumption by these territories is
32 difficult.

33 Uncertainties in the emission estimates presented above also result from the data used to allocate CO₂ emissions
34 from the transportation end-use sector to individual vehicle types and transport modes. In many cases, bottom-up
35 estimates of fuel consumption by vehicle type do not match aggregate fuel-type estimates from EIA. Further
36 research is planned to improve the allocation into detailed transportation end-use sector emissions.

37 The uncertainty analysis was performed by primary fuel type for each end-use sector, using the IPCC-
38 recommended Approach 2 uncertainty estimation methodology, Monte Carlo Stochastic Simulation technique,
39 with @RISK software. For this uncertainty estimation, the inventory estimation model for CO₂ from fossil fuel
40 combustion was integrated with the relevant variables from the inventory estimation model for International
41 Bunker Fuels, to realistically characterize the interaction (or endogenous correlation) between the variables of
42 these two models. About 170 input variables were modeled for CO₂ from energy-related Fossil Fuel Combustion
43 (including about 20 for non-energy fuel consumption and about 20 for International Bunker Fuels).

1 In developing the uncertainty estimation model, uniform distributions were assumed for all activity-related input
2 variables and emission factors, based on the SAIC/EIA (2001) report.⁴⁷ Triangular distributions were assigned for
3 the oxidization factors (or combustion efficiencies). The uncertainty ranges were assigned to the input variables
4 based on the data reported in SAIC/EIA (2001) and on conversations with various agency personnel.⁴⁸

5 The uncertainty ranges for the activity-related input variables were typically asymmetric around their inventory
6 estimates; the uncertainty ranges for the emissions factors were symmetric. Bias (or systematic uncertainties)
7 associated with these variables accounted for much of the uncertainties associated with these variables (SAIC/EIA
8 2001).⁴⁹ For purposes of this uncertainty analysis, each input variable was simulated 10,000 times through Monte
9 Carlo sampling.

10 The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-17. Fossil fuel
11 combustion CO₂ emissions in 2019 were estimated to be between 4,787.0 and 5,109.7 MMT CO₂ Eq. at a 95
12 percent confidence level. This indicates a range of 2 percent below to 5 percent above the 2019 emission estimate
13 of 4,888.5 MMT CO₂ Eq.

⁴⁷ 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.

⁴⁸ 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.

⁴⁹ 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.

1 **Table 3-17: Approach 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Energy-**
 2 **Related Fossil Fuel Combustion by Fuel Type and Sector (MMT CO₂ Eq. and Percent)**

Fuel/Sector	2019 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	1,026.8	991.7	1,123.2	-3%	9%
Residential	NO	NE	NE	NE	NE
Commercial	1.6	1.5	1.8	-5%	15%
Industrial	49.2	46.8	57.0	-5%	16%
Transportation	NE	NE	NE	NE	NE
Electric Power	973.5	936.2	1,067.5	-4%	10%
U.S. Territories	2.5	2.2	3.0	-13%	19%
Natural Gas^b	1,665.7	1,647.0	1,741.9	-1%	5%
Residential	275.3	267.5	294.6	-3%	7%
Commercial	192.8	187.3	206.3	-3%	7%
Industrial	524.3	508.8	561.9	-3%	7%
Transportation	54.8	53.2	58.6	-3%	7%
Electric Power	616.0	598.2	647.4	-3%	5%
U.S. Territories	2.5	2.2	3.0	-12%	17%
Petroleum^b	2,195.5	2,061.7	2,327.4	-6%	6%
Residential	63.5	59.9	66.9	-6%	5%
Commercial	43.9	41.7	45.9	-5%	5%
Industrial	264.0	211.4	319.0	-20%	21%
Transportation	1,788.4	1,672.4	1,905.4	-6%	7%
Electric Power	16.2	15.4	17.5	-5%	8%
U.S. Territories	19.5	18.1	21.8	-7%	11%
Total (excluding Geothermal)^b	4,888.1	4,786.5	5,109.2	-2%	5%
Geothermal	0.4	NE	NE	NE	NE
Electric Power	0.4	NE	NE	NE	NE
Total (including Geothermal)^{b,c}	4,888.5	4,787.1	5,109.7	-2%	5%

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 CO₂ emissions from geothermal production.

3 Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990
 4 through 2019. Details on the emission trends through time are described in more detail in the Methodology
 5 section, above. As discussed in Annex 5, data are unavailable to include estimates of CO₂ emissions from any liquid
 6 fuel used in pipeline transport or non-hazardous industrial waste incineration, but those emissions are assumed to
 7 be insignificant.

8 QA/QC and Verification

9 In order to ensure the quality of the CO₂ emission estimates from fossil fuel combustion, general (IPCC Tier 1) and
 10 category-specific (Tier 2) Quality Assurance/Quality Control (QA/QC) procedures were implemented consistent
 11 with the U.S. Inventory QA/QC plan outlined in Annex 8. The Tier 2 procedures that were implemented involved
 12 checks specifically focusing on the activity data and methodology used for estimating CO₂ emissions from fossil fuel

1 combustion in the United States. Emission totals for the different sectors and fuels were compared and trends
2 were investigated to determine whether any corrective actions were needed. Minor corrective actions were taken.

3 The UNFCCC reporting guidelines require countries to complete a "top-down" reference approach for estimating
4 CO₂ emissions from fossil fuel combustion in addition to their "bottom-up" sectoral methodology. The reference
5 approach (detailed in Annex 4) uses alternative methodologies and different data sources than those contained in
6 this section of the report. The reference approach estimates fossil fuel consumption by adjusting national
7 aggregate fuel production data for imports, exports, and stock changes rather than relying on end-user
8 consumption surveys. The reference approach assumes that once carbon-based fuels are brought into a national
9 economy, they are either saved in some way (e.g., stored in products, kept in fuel stocks, or left unoxidized in ash)
10 or combusted, and therefore the carbon in them is oxidized and released into the atmosphere. In the reference
11 approach, accounting for actual consumption of fuels at the sectoral or sub-national level is not required. One
12 difference between the two approaches is that emissions from carbon that was not stored during non-energy use
13 of fuels are subtracted from the sectoral approach and reported separately (see Section 3.2). These emissions,
14 however, are not subtracted in the reference approach. As a result, the reference approach emission estimates are
15 comparable to those of the sectoral approach, with the exception that the Non-Energy Use (NEU) source category
16 emissions are included in the reference approach (see Annex 4 for more details).

17 **Recalculations Discussion**

18 EIA (2020c) updated energy consumption statistics across the time series relative to the previous Inventory. As a
19 result of revised natural gas heat contents, EIA updated natural gas consumption in the residential, commercial,
20 and industrial sectors for 2018. Approximate heat rates for electricity and the heat content of electricity were
21 revised for natural gas and noncombustible renewable energy, which impacted electric power energy consumption
22 by sector. EIA also revised sector allocations for distillate fuel oil, residual fuel oil, and kerosene for 2018, and for
23 propane for 2010 through 2012, 2014, 2017, and 2018, which impacted LPG by sector. EIA revised product
24 supplied totals for crude oil and petroleum products, which impacted the nonfuel sequestration statistics,
25 particularly for lubricants for 2018 and LPG for 2010 through 2018 relative to the previous Inventory.

26 To align with EIA's methodology for calculating motor gasoline consumption, petroleum denaturant adjustments
27 to motor gasoline consumption for the period 1993 through 2008 were corrected. Newly published U.S. Territories
28 data from EIA (2020e) was integrated, which impacted total estimates for U.S. Territories across the time series.

29 EPA (2020c) revised distillate fuel oil and motor gasoline heat contents and carbon contents, which impacted
30 petroleum consumption in the transportation, residential, commercial, and industrial sectors. The combined effect
31 of both the proposed diesel fuel and gasoline emission factor update was an increase in emissions early in the time
32 series and then decreases in emissions in more recent years. For years 1990 through 2005, the average annual
33 increase in total emissions was 6.9 MMT CO₂ (0.1 percent of emissions). For the years 2006 to 2018 the average
34 annual decrease in total emissions is 4.7 MMT CO₂ (less than 0.1 percent of emissions). EPA also revised HGL C
35 contents to align with EIA's revised heat contents and HGL fuel type categorization (EIA 2020c; ICF 2020). A
36 discussion of the methodology used to develop the C content coefficients is presented in Annex 2.2.

37 To account for coal consumed during the production of coke oven gas (COG) and blast furnace gas (BFG) for energy
38 purposes (e.g., as an input to the natural gas distribution system), consumption of COG and BFG was included in
39 industrial coal consumption estimates in the energy sector, in alignment with EIA's methodology (EIA 2020c).
40 Previously, COG and BFG consumption that enters the natural gas distribution system was removed from industrial
41 natural gas consumption estimates in the energy sector. These adjustments are explained in greater detail in
42 Annex 2.1.

43 The Dakota Gasification Plant uses a coal gasification process that produces synthetic natural gas (SNG) from
44 lignite coal. Coal consumption at this plant is included in EIA's statistics for industrial coal consumption, which is
45 used to estimate CO₂ emissions from coal combustion in the U.S. Inventory. Previously, coal consumption for the
46 production of SNG was subtracted from industrial coal consumption statistics. However, SNG is not included in
47 industrial natural gas consumption data in EIA's MER and rather, SNG is accounted for in its primary energy
48 category (e.g., gasification of coal). To account for SNG from coal gasification, the adjustment to industrial coal

1 consumption to subtract the quantity of SNG produced was removed. These adjustments are explained in greater
2 detail in Annex 2.1.

3 The Dakota Gasification Plant also produces CO₂ as a byproduct. A fraction of the plant's total site-generated CO₂
4 that is captured by the plant's CO₂ capture system is exported by pipeline to Canada. The remainder of the
5 byproduct CO₂ is emitted to the atmosphere. Because the exported CO₂ is not emitted to the atmosphere in the
6 United States, the amount of associated fossil fuel (lignite coal) that is gasified to create the exported CO₂ is
7 subtracted from the EIA industrial coal consumption statistics used in the Inventory, so that the amount of CO₂
8 exported is not included in the reported greenhouse gas emissions from the Energy Sector. Previously, the amount
9 of CO₂ captured and exported by pipeline annually was estimated from publicly available data for plant operations,
10 including historical CO₂ export data and the publicly reported transport (CO₂ gas compressor) capacity of the CO₂
11 pipeline, assuming that the CO₂ pipeline operates at 100 percent of the pipeline's transport capacity. To ensure
12 consistency in reporting between the Inventory and the Canadian National Greenhouse Gas Inventory, the amount
13 of associated fossil fuel (lignite coal) that is gasified to create the exported CO₂ has been revised to align with the
14 Canadian National Greenhouse Gas Inventory (Environment and Climate Change Canada 2020). These adjustments
15 are explained in greater detail in Annex 2.1.

16 EIA's revisions to fuel consumption statistics in EIA (2020c) and U.S. Territories (EIA 2020e), as well as updates to
17 carbon contents and heat contents, resulted in an average annual decrease of 6.4 MMT CO₂ Eq. (0.3 percent) in
18 CO₂ emissions from petroleum across the time series. Revisions to EIA (2020e) data for U.S. Territories resulted in
19 an average annual decrease of 2.9 MMT CO₂ Eq. (0.2 percent) in CO₂ emissions from coal. Revisions to natural gas
20 consumption across all sectors resulted in a decrease of 0.7 MMT CO₂ Eq. (less than 0.1 percent) in CO₂ emissions
21 from natural gas in 2018. Overall, these changes resulted in an average annual decrease of 3.4 MMT CO₂ Eq. (less
22 than 0.1 percent) in CO₂ emissions from fossil fuel combustion for the period 1990 through 2018, relative to the
23 previous Inventory.

24 **Planned Improvements**

25 To reduce uncertainty of CO₂ from fossil fuel combustion estimates for U.S. Territories, further expert elicitation
26 may be conducted to better quantify the total uncertainty associated with emissions from U.S. Territories.

27 The availability of facility-level combustion emissions through EPA's GHGRP will continue to be examined to help
28 better characterize the industrial sector's energy consumption in the United States and further classify total
29 industrial sector fossil fuel combustion emissions by business establishments according to industrial economic
30 activity type. Most methodologies used in EPA's GHGRP are consistent with IPCC methodologies, though for EPA's
31 GHGRP, facilities collect detailed information specific to their operations according to detailed measurement
32 standards, which may differ with the more aggregated data collected for the Inventory to estimate total, national
33 U.S. emissions. In addition, and unlike the reporting requirements for this chapter under the UNFCCC reporting
34 guidelines, some facility-level fuel combustion emissions reported under the GHGRP may also include industrial
35 process emissions.⁵⁰ In line with UNFCCC reporting guidelines, fuel combustion emissions are included in this
36 chapter, while process emissions are included in the Industrial Processes and Product Use chapter of this report. In
37 examining data from EPA's GHGRP that would be useful to improve the emission estimates for the CO₂ from fossil
38 fuel combustion category, particular attention will also be made to ensure time-series consistency, as the facility-
39 level reporting data from EPA's GHGRP are not available for all inventory years as reported in this Inventory.

40 Additional analyses will be conducted to align reported facility-level fuel types and IPCC fuel types per the national
41 energy statistics. For example, efforts will be taken to incorporate updated industrial fuel consumption data from
42 EIA's Manufacturing Energy Consumption Survey (MECS), with updated data for 2018. Additional work will look at
43 CO₂ emissions from biomass to ensure they are separated in the facility-level reported data and maintaining
44 consistency with national energy statistics provided by EIA. In implementing improvements and integration of data

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

1 from EPA’s GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will
2 continue to be relied upon.⁵¹

3 An ongoing planned improvement is to develop improved estimates of domestic waterborne fuel consumption.
4 The Inventory estimates for residual and distillate fuel used by ships and boats is based in part on data on bunker
5 fuel use from the U.S. Department of Commerce. Domestic fuel consumption is estimated by subtracting fuel sold
6 for international use from the total sold in the United States. It may be possible to more accurately estimate
7 domestic fuel use and emissions by using detailed data on marine ship activity. The feasibility of using domestic
8 marine activity data to improve the estimates will continue to be investigated.

9 EPA is also evaluating the methods used to adjust for conversion of fuels and exports of CO₂. EPA is exploring the
10 approach used to account for CO₂ transport, injection, and geologic storage, as part of this there may be changes
11 made to accounting for CO₂ exports. EPA is also exploring the data provided by EIA in terms of tracking
12 supplemental natural gas which may impact the treatment of adjustments for synthetic fuels.

13 CH₄ and N₂O from Stationary Combustion

14 Methodology

15 Methane and N₂O emissions from stationary combustion were estimated by multiplying fossil fuel and wood
16 consumption data by emission factors (by sector and fuel type for industrial, residential, commercial, and U.S.
17 Territories; and by fuel and technology type for the electric power sector). The electric power sector utilizes a Tier
18 2 methodology, whereas all other sectors utilize a Tier 1 methodology. The activity data and emission factors used
19 are described in the following subsections.

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

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

23 National coal, natural gas, fuel oil, and wood consumption data were grouped by sector: industrial, commercial,
24 residential, and U.S. Territories. For the CH₄ and N₂O emission estimates, consumption data for each fuel were
25 obtained from EIA’s *Monthly Energy Review* (EIA 2020a). Because the United States does not include territories in
26 its national energy statistics, fuel consumption data for territories were provided separately by EIA’s International
27 Energy Statistics (EIA 2020b).⁵² Fuel consumption for the industrial sector was adjusted to subtract out mobile
28 source construction and agricultural use, which is reported under mobile sources. Construction and agricultural
29 mobile source fuel use was obtained from EPA (2019) and FHWA (1996 through 2019). Estimates for wood biomass
30 consumption for fuel combustion do not include municipal solid waste, tires, etc., that are reported as biomass by
31 EIA. Non-CO₂ emissions from combustion of the biogenic portion of municipal solid waste and tires is included
32 under waste incineration (Section 3.2). Estimates for natural gas combustion do not include biogas, and therefore
33 non-CO₂ emissions from biogas are not included (see the Planned Improvements section, below). Tier 1 default
34 emission factors for the industrial, commercial, and residential end-use sectors were provided by the *2006 IPCC*
35 *Guidelines for National Greenhouse Gas Inventories* (IPCC 2006). U.S. Territories’ emission factors were estimated
36 using the U.S. emission factors for the primary sector in which each fuel was combusted.

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

⁵² U.S. Territories data also include combustion from mobile activities because data to allocate territories’ energy use were unavailable. For this reason, CH₄ and N₂O emissions from combustion by U.S. Territories are only included in the stationary combustion totals.

1 *Electric Power Sector*

2 The electric power sector uses a Tier 2 emission estimation methodology as fuel consumption for the electric
3 power sector by control-technology type was based on EPA's Acid Rain Program Dataset (EPA 2020a). Total fuel
4 consumption in the electric power sector from EIA (2020a) was apportioned to each combustion technology type
5 and fuel combination using a ratio of fuel consumption by technology type derived from EPA (2020a) data. The
6 combustion technology and fuel use data by facility obtained from EPA (2020a) were only available from 1996 to
7 2019, so the consumption estimates from 1990 to 1995 were estimated by applying the 1996 consumption ratio by
8 combustion technology type from EPA (2020a) to the total EIA (2020a) consumption for each year from 1990 to
9 1995.

10 Emissions were estimated by multiplying fossil fuel and wood consumption by technology-, fuel-, and country-
11 specific Tier 2 emission factors. The Tier 2 emission factors used are based in part on emission factors published by
12 EPA, and EPA's Compilation of Air Pollutant Emission Factors, AP-42 (EPA 1997) for coal wall-fired boilers, residual
13 fuel oil, diesel oil and wood boilers, natural gas-fired turbines, and combined cycle natural gas units.⁵³

14 **Uncertainty and Time-Series Consistency**

15 Methane emission estimates from stationary sources exhibit high uncertainty, primarily due to difficulties in
16 calculating emissions from wood combustion (i.e., fireplaces and wood stoves). The estimates of CH₄ and N₂O
17 emissions presented are based on broad indicators of emissions (i.e., fuel use multiplied by an aggregate emission
18 factor for different sectors), rather than specific emission processes (i.e., by combustion technology and type of
19 emission control).

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

23 The uncertainty estimation model for this source category was developed by integrating the CH₄ and N₂O
24 stationary source inventory estimation models with the model for CO₂ from fossil fuel combustion to realistically
25 characterize the interaction (or endogenous correlation) between the variables of these three models. About 55
26 input variables were simulated for the uncertainty analysis of this source category (about 20 from the CO₂
27 emissions from fossil fuel combustion inventory estimation model and about 35 from the stationary source
28 inventory models).

29 In developing the uncertainty estimation model, uniform distribution was assumed for all activity-related input
30 variables and N₂O emission factors, based on the SAIC/EIA (2001) report.⁵⁴ For these variables, the uncertainty
31 ranges were assigned to the input variables based on the data reported in SAIC/EIA (2001).⁵⁵ However, the CH₄
32 emission factors differ from those used by EIA. These factors and uncertainty ranges are based on IPCC default
33 uncertainty estimates (IPCC 2006).

⁵³ Several of the U.S. Tier 2 emission factors were used in IPCC (2006) as Tier 1 emission factors. See Table A-77 in Annex 3.1 for emission factors by technology type and fuel type for the electric power sector.

⁵⁴ 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.

⁵⁵ 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.

1 The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-18. Stationary
 2 combustion CH₄ emissions in 2019 (including biomass) were estimated to be between 5.4 and 20.1 MMT CO₂ Eq. at
 3 a 95 percent confidence level. This indicates a range of 37 percent below to 133 percent above the 2019 emission
 4 estimate of 8.6 MMT CO₂ Eq.⁵⁶ Stationary combustion N₂O emissions in 2019 (including biomass) were estimated
 5 to be between 18.6 and 37.7 MMT CO₂ Eq. at a 95 percent confidence level. This indicates a range of 25 percent
 6 below to 52 percent above the 2019 emission estimate of 24.9 MMT CO₂ Eq.

7 **Table 3-18: Approach 2 Quantitative Uncertainty Estimates for CH₄ and N₂O Emissions from**
 8 **Energy-Related Stationary Combustion, Including Biomass (MMT CO₂ Eq. and Percent)**

Source	Gas	2019 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	5.4	20.1	-37%	+133%
Stationary Combustion	N ₂ O	24.9	18.6	37.7	-25%	+52%

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

9 The uncertainties associated with the emission estimates of CH₄ and N₂O are greater than those associated with
 10 estimates of CO₂ from fossil fuel combustion, which mainly rely on the carbon content of the fuel combusted.
 11 Uncertainties in both CH₄ and N₂O estimates are due to the fact that emissions are estimated based on emission
 12 factors representing only a limited subset of combustion conditions. For the indirect greenhouse gases,
 13 uncertainties are partly due to assumptions concerning combustion technology types, age of equipment, emission
 14 factors used, and activity data projections.

15 Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990
 16 through 2018 as discussed below. Details on the emission trends through time are described in more detail in the
 17 Methodology section, above. As discussed in Annex 5, data are unavailable to include estimates of CH₄ and N₂O
 18 emissions from biomass use in Territories, but those emissions are assumed to be insignificant.

19 QA/QC and Verification

20 In order to ensure the quality of the non-CO₂ emission estimates from stationary combustion, general (IPCC Tier 1)
 21 and category-specific (Tier 2) Quality Assurance/Quality Control (QA/QC) procedures were implemented consistent
 22 with the U.S. Inventory QA/QC plan outlined in Annex 8. The Tier 2 procedures that were implemented involved
 23 checks specifically focusing on the activity data and emission factor sources and methodology used for estimating
 24 CH₄, N₂O, and the greenhouse gas precursors from stationary combustion in the United States. Emission totals for
 25 the different sectors and fuels were compared and trends were investigated.

26 Recalculations Discussion

27 Methane and N₂O emissions from stationary sources (excluding CO₂) across the entire time series were revised due
 28 to revised data from EIA (2020a) and EPA (2020a) relative to the previous Inventory. Most notably, newly
 29 published U.S. Territories data from EIA (2020b) was integrated, which impacted coal, fuel oil, and natural gas
 30 estimates for U.S. Territories across the time series. EIA (2020a) revised approximate heat rates for electricity and
 31 the heat content of electricity for natural gas and noncombustible renewable energy, which impacted electric
 32 power energy consumption by sector. As a result of revised natural gas heat contents, EIA updated natural gas
 33 consumption in the residential, commercial, and industrial sectors for 2018.

⁵⁶ 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.

1 EIA also revised sector allocations for distillate fuel oil, residual fuel oil, and kerosene for 2018, and for propane for
2 2010 through 2012, 2014, 2017, and 2018, which impacted LPG by sector. EPA (2020a) revised coal, fuel oil,
3 natural gas, and wood consumption statistics for 2018 in the electric power sector. EPA revised distillate fuel oil
4 and LPG heat contents and carbon contents, which affect petroleum consumption in the residential, commercial,
5 and industrial sectors (EPA 2020b; ICF 2020). The historical data changes and methodology updates resulted in an
6 average annual decrease of 0.1 MMT CO₂ Eq. (0.9 percent) in CH₄ emissions, and an average annual decrease of
7 0.1 MMT CO₂ Eq. (0.5 percent) in N₂O emissions for the 1990 through 2018 period.

8 **Planned Improvements**

9 Several items are being evaluated to improve the CH₄ and N₂O emission estimates from stationary combustion and
10 to reduce uncertainty for U.S. Territories. Efforts will be taken to work with EIA and other agencies to improve the
11 quality of the U.S. Territories data. Because these data are not broken out by stationary and mobile uses, further
12 research will be aimed at trying to allocate consumption appropriately. In addition, the uncertainty of biomass
13 emissions will be further investigated since it was expected that the exclusion of biomass from the estimates
14 would reduce the uncertainty; and in actuality the exclusion of biomass increases the uncertainty. These
15 improvements are not all-inclusive but are part of an ongoing analysis and efforts to continually improve these
16 stationary combustion estimates from U.S. Territories.

17 Other forms of biomass-based gas consumption include biogas. EPA will examine EIA and GHGRP data on biogas
18 collected and burned for energy use and determine if CH₄ and N₂O emissions from biogas can be included in future
19 inventories. EIA (2020a) natural gas data already deducts biogas used in the natural gas supply, so no adjustments
20 are needed to the natural gas fuel consumption data to account for biogas.

21 **CH₄ and N₂O from Mobile Combustion**

22 **Methodology**

23 Estimates of CH₄ and N₂O emissions from mobile combustion were calculated by multiplying emission factors by
24 measures of activity for each fuel and vehicle type (e.g., light-duty gasoline trucks). Activity data included vehicle
25 miles traveled (VMT) for on-road vehicles and fuel consumption for non-road mobile sources. The activity data and
26 emission factors used in the calculations are described in the subsections that follow. A complete discussion of the
27 methodology used to estimate CH₄ and N₂O emissions from mobile combustion and the emission factors used in the
28 calculations is provided in Annex 3.2.

29 *On-Road Vehicles*

30 Estimates of CH₄ and N₂O emissions from gasoline and diesel on-road vehicles are based on VMT and emission
31 factors (in grams of CH₄ and N₂O per mile) by vehicle type, fuel type, model year, and emission control technology.
32 Emission estimates for alternative fuel vehicles (AFVs) are based on VMT and emission factors (in grams of CH₄ and
33 N₂O per mile) by vehicle and fuel type.⁵⁷

34 CH₄ and N₂O emissions factors for newer (starting with model year 2004) on-road gasoline vehicles were calculated
35 by Browning (2019) from annual vehicle certification data compiled by EPA. CH₄ and N₂O emissions factors for
36 older (model year 2003 and earlier) on-road gasoline vehicles were developed by ICF (2004). These emission
37 factors were derived from EPA, California Air Resources Board (CARB) and Environment and Climate Change
38 Canada laboratory test results of different vehicle and control technology types. The EPA, CARB and Environment
39 and Climate Change Canada tests were designed following the Federal Test Procedure (FTP). The procedure covers
40 three separate driving segments, since vehicles emit varying amounts of greenhouse gases depending on the

⁵⁷ 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.

1 driving segment. These driving segments are: (1) a transient driving cycle that includes cold start and running
2 emissions, (2) a cycle that represents running emissions only, and (3) a transient driving cycle that includes hot
3 start and running emissions. For each test run, a bag was affixed to the tailpipe of the vehicle and the exhaust was
4 collected; the content of this bag was then analyzed to determine quantities of gases present. The emissions
5 characteristics of driving segment 2 tests were used to define running emissions. Running emissions were
6 subtracted from the total FTP emissions to determine start emissions. These were then recombined to
7 approximate average driving characteristics, based upon the ratio of start to running emissions for each vehicle
8 class from MOBILE6.2, an EPA emission factor model that predicts gram per mile emissions of CO₂, CO, HC, NO_x,
9 and PM from vehicles under various conditions.⁵⁸

10 Diesel on-road vehicle emission factors were developed by ICF (2006a). CH₄ and N₂O emissions factors for newer
11 (starting at model year 2007) on-road diesel vehicles (those using engine aftertreatment systems) were calculated
12 from annual vehicle certification data compiled by EPA.

13 CH₄ and N₂O emission factors for AFVs were developed based on the 2019 Greenhouse gases, Regulated
14 Emissions, and Energy use in Transportation (GREET) model (ANL 2019). For light-duty trucks, EPA used a curve fit
15 of 1999 through 2011 travel fractions for LDT1 and LDT2 (MOVES Source Type 31 for LDT1 and MOVES Source Type
16 32 for LDT2). For medium-duty vehicles, EPA used emission factors for light heavy-duty vocational trucks. For
17 heavy-duty vehicles, EPA used emission factors for long-haul combination trucks. For buses, EPA used emission
18 factors for transit buses. These values represent vehicle operations only (tank-to-wheels); upstream well-to-tank
19 emissions are calculated elsewhere in the Inventory. Biodiesel CH₄ emission factors were corrected from GREET
20 values to be the same as CH₄ emission factors for diesel vehicles. GREET overestimated biodiesel CH₄ emission
21 factors based upon an incorrect CH₄-to-THC ratio for diesel vehicles with aftertreatment technology.

22 Annual VMT data for 1990 through 2019 were obtained from the Federal Highway Administration's (FHWA)
23 Highway Performance Monitoring System database as reported in Highway Statistics (FHWA 1996 through 2019).⁵⁹
24 VMT estimates were then allocated from FHWA's vehicle categories to fuel-specific vehicle categories using the
25 calculated shares of vehicle fuel use for each vehicle category by fuel type reported in DOE (1993 through 2018)
26 and information on total motor vehicle fuel consumption by fuel type from FHWA (1996 through 2019). VMT for
27 AFVs were estimated based on Browning (2017 and 2018a). The age distributions of the U.S. vehicle fleet were
28 obtained from EPA (2019a, 2000), and the average annual age-specific vehicle mileage accumulation of U.S.
29 vehicles were obtained from EPA (2019a).

30 Control technology and standards data for on-road vehicles were obtained from EPA's Office of Transportation and
31 Air Quality (EPA 2019a, 2020c, 2000, 1998, and 1997) and Browning (2005). These technologies and standards are
32 defined in Annex 3.2, and were compiled from EPA (1994a, 1994b, 1998, 1999a) and IPCC (2006) sources.

33 *Non-Road Mobile Sources*

34 To estimate CH₄ and N₂O emissions from non-road mobile sources, fuel consumption data were employed as a
35 measure of activity, and multiplied by fuel-specific emission factors (in grams of N₂O and CH₄ per kilogram of fuel

⁵⁸ 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>>.

⁵⁹ The source of VMT data 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 2019 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.

1 consumed).⁶⁰ Activity data were obtained from AAR (2008 through 2019), APTA (2007 through 2018), RailInc (2014
 2 through 2019), APTA (2006), BEA (1991 through 2015), Benson (2002 through 2004), DLA Energy (2019), DOC
 3 (1991 through 2019), DOE (1993 through 2017), DOT (1991 through 2019), EIA (2002, 2007, 2020a), EIA (2020f),
 4 EIA (1991 through 2019), EPA (2019a), Esser (2003 through 2004), FAA (2019), FHWA (1996 through 2019),⁶¹
 5 Gaffney (2007), and Whorton (2006 through 2014). Emission factors for non-road modes were taken from IPCC
 6 (2006) and Browning (2020 and 2018b).

7 **Uncertainty and Time-Series Consistency**

8 A quantitative uncertainty analysis was conducted for the mobile source sector using the IPCC-recommended
 9 Approach 2 uncertainty estimation methodology, Monte Carlo Stochastic Simulation technique, using @RISK
 10 software. The uncertainty analysis was performed on 2019 estimates of CH₄ and N₂O emissions, incorporating
 11 probability distribution functions associated with the major input variables. For the purposes of this analysis, the
 12 uncertainty was modeled for the following four major sets of input variables: (1) VMT data, by on-road vehicle and
 13 fuel type, (2) emission factor data, by on-road vehicle, fuel, and control technology type, (3) fuel consumption,
 14 data, by non-road vehicle and equipment type, and (4) emission factor data, by non-road vehicle and equipment
 15 type.

16 Uncertainty analyses were not conducted for NO_x, CO, or NMVOC emissions. Emission factors for these gases have
 17 been extensively researched because emissions of these gases from motor vehicles are regulated in the United
 18 States, and the uncertainty in these emission estimates is believed to be relatively low. For more information, see
 19 Section 3.9 – Uncertainty Analysis of Emission Estimates. However, a much higher level of uncertainty is associated
 20 with CH₄ and N₂O emission factors due to limited emission test data, and because, unlike CO₂ emissions, the
 21 emission pathways of CH₄ and N₂O are highly complex.

22 Based on the uncertainty analysis, mobile combustion CH₄ emissions from all mobile sources in 2018 were
 23 estimated to be between 2.9 and 4.0 MMT CO₂ Eq. at a 95 percent confidence level. This indicates a range of 8
 24 percent below to 27 percent above the corresponding 2018 emission estimate of 3.1 MMT CO₂ Eq. Mobile
 25 combustion N₂O emissions from mobile sources in 2018 were estimated to be between 14.0 and 17.4 MMT CO₂
 26 Eq. at a 95 percent confidence level. This indicates a range of 8 percent below to 14 percent above the
 27 corresponding 2018 emission estimate of 15.2 MMT CO₂ Eq.

28 **Table 3-19: Approach 2 Quantitative Uncertainty Estimates for CH₄ and N₂O Emissions from**
 29 **Mobile Sources (MMT CO₂ Eq. and Percent)**

Source	Gas	2018 Emission Estimate ^a (MMT CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			(MMT CO ₂ Eq.)		(Percent)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Mobile Sources	CH ₄	3.1	2.9	4.0	-8%	+27%
Mobile Sources	N ₂ O	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.

⁶⁰ The consumption of international bunker fuels is not included in these activity data, but emissions related to the consumption of international bunker fuels are estimated separately under the International Bunker Fuels source category.

⁶¹ 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 CH₄ and N₂O emissions for these categories. For agriculture, the MF-24 gasoline volume is used directly because it includes both non-road trucks and equipment. For construction and commercial/industrial category gasoline estimates, the 2014 and older MF-24 volumes represented non-road trucks only; therefore, the MOVES gasoline volumes for construction and commercial/industrial categories 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.

1 This uncertainty analysis is a continuation of a multi-year process for developing quantitative uncertainty estimates
2 for this source category using the IPCC Approach 2 uncertainty estimation methodology. As a result, as new
3 information becomes available, uncertainty characterization of input variables may be improved and revised. For
4 additional information regarding uncertainty in emission estimates for CH₄ and N₂O please refer to the Uncertainty
5 Annex. As discussed in Annex 5, data are unavailable to include estimates of CH₄ and N₂O emissions from any liquid
6 fuel used in pipeline transport or some biomass used in transportation sources, but those emissions are assumed
7 to be insignificant.

8 **QA/QC and Verification**

9 In order to ensure the quality of the emission estimates from mobile combustion, general (IPCC Tier 1) and
10 category-specific (Tier 2) Quality Assurance/Quality Control (QA/QC) procedures were implemented consistent
11 with the U.S. Inventory QA/QC plan outlined in Annex 8. The specific plan used for mobile combustion was
12 updated prior to collection and analysis of this current year of data. The Tier 2 procedures focused on the emission
13 factor and activity data sources, as well as the methodology used for estimating emissions. These procedures
14 included a qualitative assessment of the emission estimates to determine whether they appear consistent with the
15 most recent activity data and emission factors available. A comparison of historical emissions between the current
16 Inventory and the previous Inventory was also conducted to ensure that the changes in estimates were consistent
17 with the changes in activity data and emission factors.

18 **Recalculations Discussion**

19 Updates were made to CH₄ and N₂O emission factors for newer non-road gasoline and diesel vehicles. Previously,
20 these emission factors were calculated using the updated 2006 IPCC Tier 3 guidance and the nonroad component
21 EPA's MOVES2014b model. CH₄ emission factors were calculated directly from MOVES. N₂O emission factors are
22 calculated using MOVES-Nonroad activity and emission factors in g/kWh by fuel type from the European
23 Environment Agency. Updated emission factors were developed this year using EPA engine certification data for
24 non-road small and large spark-ignition (SI) gasoline engines and compression-ignition diesel engines (2011 and
25 newer), as well as non-road motorcycles (2006 and newer), SI marine engines (2011 and newer), and diesel marine
26 engines (2000 and newer).

27 The collective result of these changes was a net decrease in CH₄ emissions and an increase in N₂O emissions from
28 mobile combustion relative to the previous Inventory. Methane emissions decreased by 23.0 percent. Nitrous
29 oxide emissions increased by 25.7 percent.

30 Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990
31 through 2019 with one recent notable exception. An update by FHWA to the method for estimating on-road VMT
32 created an inconsistency in on-road CH₄ and N₂O for the time periods 1990 to 2006 and 2007 to 2019. Details on
33 the emission trends and methodological inconsistencies through time are described in the Methodology section
34 above.

35 **Planned Improvements**

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

- 38 • Update emissions factors for ships and boats using residual fuel and distillate fuel, emission factors for
39 locomotives using ultra low sulfur diesel, and emission factors for aircraft using jet fuel. The Inventory is
40 currently using IPCC default values for these emissions factors.
- 41 • Continue to explore potential improvements to estimates of domestic waterborne fuel consumption for
42 future Inventories. The Inventory estimates for residual and distillate fuel used by ships and boats is based
43 in part on data on bunker fuel use from the U.S. Department of Commerce. Domestic fuel consumption is
44 estimated by subtracting fuel sold for international use from the total sold in the United States. It may be

1 possible to more accurately estimate domestic fuel use and emissions by using detailed data on marine
2 vessel activity. The feasibility of using domestic marine activity data to improve the estimates continues to
3 be investigated. Additionally, the feasibility of including data from a broader range of domestic and
4 international sources for domestic bunker fuels, including data from studies such as the *Fourth IMO GHG*
5 *Study 2020*, continues to be explored.

6 3.2 Carbon Emitted from Non-Energy Uses of 7 Fossil Fuels (CRF Source Category 1A)

8 In addition to being combusted for energy, fossil fuels are also consumed for non-energy uses (NEU) in the United
9 States. The fuels used for these purposes are diverse, including natural gas, hydrocarbon gas liquids (HGL),⁶²
10 asphalt (a viscous liquid mixture of heavy crude oil distillates), petroleum coke (manufactured from heavy oil), and
11 coal (metallurgical) coke (manufactured from coking coal). The non-energy applications of these fuels are equally
12 diverse, including feedstocks for the manufacture of plastics, rubber, synthetic fibers and other materials; reducing
13 agents for the production of various metals and inorganic products; and products such as lubricants, waxes, and
14 asphalt (IPCC 2006). Emissions from non-energy use of lubricants, paraffin waxes, bitumen / asphalt, and solvents
15 are reported in the Energy sector, as opposed to the Industrial Processes and Product Use (IPPU) sector, to reflect
16 national circumstances in its choice of methodology and to increase transparency of this source category's unique
17 country-specific data sources and methodology (see Box 3-5). In addition, estimates of non-energy use emissions
18 included here do not include emissions already reflected in the IPPU sector, e.g., fuels used as reducing agents. To
19 avoid double counting, the "raw" non-energy fuel consumption data reported by EIA are reduced to account for
20 these emissions already included under IPPU.

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

26 There are several areas in which non-energy uses of fossil fuels are closely related to other parts of this Inventory.
27 For example, some of the non-energy use products release CO₂ at the end of their commercial life when they are
28 combusted after disposal; these emissions are reported separately within the Energy chapter in the Incineration of
29 Waste source category. There are also net exports of petrochemical intermediate products that are not completely
30 accounted for in the EIA data, and the Inventory calculations adjust for the effect of net exports on the mass of C in
31 non-energy applications.

32 As shown in Table 3-20, fossil fuel emissions in 2019 from the non-energy uses of fossil fuels were 110.1 MMT CO₂
33 Eq., which constituted approximately 2 percent of overall fossil fuel emissions. In 2019, the consumption of fuels
34 for non-energy uses (after the adjustments described above) was 5,242.7 TBtu (see Table 3-21). A portion of the C
35 in the 5,242.7 TBtu of fuels was stored (229.0 MMT CO₂ Eq.), while the remaining portion was emitted (110.1 MMT
36 CO₂ Eq.). Non-energy use emissions decreased by 0.7 percent from 2018 to 2019 mainly due to a decrease in the
37 ratio between C stored and potential emissions. See Annex 2.3 for more details.

⁶² HGL (formerly referred to as liquefied petroleum gas, or LPG) are hydrocarbons that occur as gases at atmospheric pressure and as liquids under higher pressures. HGLs include paraffins, such as ethane, propane, butanes, and pentanes plus, and HGLs include olefins, such as ethylene, propylene, and butylene. Adjustments were made in the current Inventory report to HGL activity data, carbon content coefficients, and heat contents HGL. For more information about the updated HGL data and assumptions, see the Recalculations Discussion section below.

1 **Table 3-20: CO₂ Emissions from Non-Energy Use Fossil Fuel Consumption (MMT CO₂ Eq. and**
 2 **Percent)**

Year	1990	2005	2015	2016	2017	2018	2019
Potential Emissions	306.1	369.0	320.0	309.0	319.1	334.2	339.1
C Stored	193.3	238.4	214.6	215.4	219.4	223.4	229.0
Emissions as a % of Potential	37%	35%	33%	30%	31%	33%	32%
C Emitted	112.8	130.6	105.3	93.6	99.7	110.9	110.1

3 Methodology

4 The first step in estimating C stored in products was to determine the aggregate quantity of fossil fuels consumed
 5 for non-energy uses. The C content of these feedstock fuels is equivalent to potential emissions, or the product of
 6 consumption and the fuel-specific C content values. Both the non-energy fuel consumption and C content data
 7 were supplied by the EIA (2020) (see Annex 2.1). Consumption values for industrial coking coal, petroleum coke,
 8 other oils, and natural gas in Table 3-21 and Table 3-22 have been adjusted to subtract non-energy uses that are
 9 included in the source categories of the Industrial Processes and Product Use chapter.⁶³ Consumption of natural
 10 gas, HGL, pentanes plus, naphthas, other oils, and special naphtha were adjusted to subtract out net exports of
 11 these products that are not reflected in the raw data from EIA. Consumption values were also adjusted to subtract
 12 net exports of HGL components (e.g., propylene, ethane).

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

- 15 • For several fuel types—petrochemical feedstocks (including natural gas for non-fertilizer uses, HGL,
 16 pentanes plus, naphthas, other oils, still gas, special naphtha, and industrial other coal), asphalt and road
 17 oil, lubricants, and waxes—U.S. data on C stocks and flows were used to develop C storage factors,
 18 calculated as the ratio of (a) the C stored by the fuel’s non-energy products to (b) the total C content of
 19 the fuel consumed. A lifecycle approach was used in the development of these factors in order to account
 20 for losses in the production process and during use. Because losses associated with municipal solid waste
 21 management are handled separately in the Energy sector under the Incineration of Waste source
 22 category, the storage factors do not account for losses at the disposal end of the life cycle.
- 23 • For industrial coking coal and distillate fuel oil, storage factors were taken from Marland and Rotty (1984).
- 24 • For the remaining fuel types (petroleum coke, miscellaneous products, and other petroleum), IPCC (2006)
 25 does not provide guidance on storage factors, and assumptions were made based on the potential fate of
 26 C in the respective non-energy use products. Carbon dioxide emissions from carbide production are
 27 implicitly accounted for in the storage factor calculation for the non-energy use of petroleum coke.

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

Year	1990	2005	2015	2016	2017	2018	2019
Industry	4,317.2	5,111.1	4,764.8	4,635.2	4,793.3	5,051.5	5,099.9
Industrial Coking Coal	NO	80.4	121.8	89.1	112.4	125.0	132.8
Industrial Other Coal	7.6	11.0	9.5	9.5	9.5	9.5	9.5
Natural Gas to Chemical Plants	282.4	260.9	322.0	309.0	307.6	304.7	299.1
Asphalt & Road Oil	1,170.2	1,323.2	831.7	853.4	849.2	792.8	843.9

⁶³ 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.

HGL	1,218.4	1,610.4	2,158.6	2,120.4	2,182.0	2,487.5	2,523.7
Lubricants	186.3	160.2	142.1	135.1	124.9	121.9	117.6
Pentanes Plus	117.5	95.4	78.3	52.9	81.3	104.5	153.5
Naphtha (<401 °F)	327.0	679.5	417.8	396.9	411.1	418.3	366.0
Other Oil (>401 °F)	663.6	499.5	216.8	204.0	241.8	217.7	210.2
Still Gas	36.7	67.7	162.2	166.1	163.8	166.9	158.7
Petroleum Coke	28.1	106.2	NO	NO	NO	NO	NO
Special Naphtha	101.1	60.9	97.0	88.7	94.9	86.5	88.7
Distillate Fuel Oil	7.0	11.7	5.8	5.8	5.8	5.8	5.8
Waxes	33.3	31.4	12.4	12.8	10.2	12.4	10.4
Miscellaneous Products	137.8	112.8	188.9	191.3	198.8	198.0	180.2
Transportation	176.0	151.3	162.8	154.4	142.0	137.0	132.1
Lubricants	176.0	151.3	162.8	154.4	142.0	137.0	132.1
U.S. Territories	50.8	114.9	10.3	10.5	10.7	10.7	10.7
Lubricants	0.7	4.6	1.0	1.0	1.0	1.0	1.0
Other Petroleum (Misc. Prod.)	50.1	110.3	9.3	9.5	9.6	9.6	9.6
Total	4,544.0	5,377.3	4,938.0	4,800.0	4,945.9	5,199.2	5,242.7

NO (Not Occurring)

1 **Table 3-22: 2019 Adjusted Non-Energy Use Fossil Fuel Consumption, Storage, and Emissions**

Sector/Fuel Type	Adjusted		Potential Carbon (MMT C)	Storage Factor	Carbon Stored (MMT C)	Carbon Emissions (MMT C)	Carbon Emissions (MMT CO ₂ Eq.)
	Non-Energy Use ^a (TBtu)	Carbon Content Coefficient (MMT C/QBtu)					
Industry	5,099.4	NA	89.6	NA	62.2	27.4	100.5
Industrial Coking Coal	132.8	31.00	4.1	0.10	0.4	3.7	13.6
Industrial Other Coal	9.5	26.07	0.2	0.67	0.2	0.1	0.3
Natural Gas to							
Chemical Plants	299.1	14.47	4.3	0.67	2.9	1.4	5.2
Asphalt & Road Oil	843.9	20.55	17.3	1.00	17.3	0.1	0.3
HGL	2,523.7	16.85	42.5	0.67	28.7	13.9	50.8
Lubricants	117.6	20.20	2.4	0.09	0.2	2.2	7.9
Pentanes Plus	153.5	18.24	2.8	0.67	1.9	0.9	3.3
Naphtha (<401° F)	366.0	18.55	6.8	0.67	4.6	2.2	8.1
Other Oil (>401° F)	210.2	20.17	4.2	0.67	2.9	1.4	5.1
Still Gas	158.7	17.51	2.8	0.67	1.9	0.9	3.3
Petroleum Coke	NO	27.85	NO	0.30	NO	NO	NO
Special Naphtha	88.7	19.74	1.7	0.67	1.2	0.6	2.1
Distillate Fuel Oil	5.8	20.22	0.1	0.50	0.1	0.1	0.2
Waxes	10.4	19.80	0.2	0.58	0.1	0.1	0.3
Miscellaneous Products	180.2	0.00	0.0	0.00	0.0	0.0	0.0
Transportation	132.1	NA	2.7	NA	0.2	2.4	8.9
Lubricants	132.1	20.20	2.7	0.09	0.2	2.4	8.9
U.S. Territories	10.7	NA	0.2	NA	0.0	0.2	0.7
Lubricants	1.0	20.20	+	0.09	+	+	0.1
Other Petroleum (Misc. Prod.)	9.6	20.00	0.2	0.10	+	0.2	0.6
Total	5,242.7		92.5		62.5	30.0	110.1

Note: Totals may not sum due to independent rounding.

+ Does not exceed 0.05 TBtu, MMT C, or MMT CO₂ Eq.

NA (Not Applicable)

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

1 Lastly, emissions were estimated by subtracting the C stored from the potential emissions (see Table 3-20). More
2 detail on the methodology for calculating storage and emissions from each of these sources is provided in Annex
3 2.3.

4 Where storage factors were calculated specifically for the United States, data were obtained on (1) products such
5 as asphalt, plastics, synthetic rubber, synthetic fibers, cleansers (soaps and detergents), pesticides, food additives,
6 antifreeze and deicers (glycols), and silicones; and (2) industrial releases including energy recovery (waste gas from
7 chemicals), Toxics Release Inventory (TRI) releases, hazardous waste incineration, and volatile organic compound,
8 solvent, and non-combustion CO emissions. Data were taken from a variety of industry sources, government
9 reports, and expert communications. Sources include EPA reports and databases such as compilations of air
10 emission factors (EPA 2001), *National Emissions Inventory (NEI) Air Pollutant Emissions Trends Data* (EPA 2020),
11 *Toxics Release Inventory, 1998* (EPA 2000b), *Biennial Reporting System* (EPA 2000a, 2009), *Resource Conservation*
12 *and Recovery Act Information System* (EPA 2013b, 2015, 2016b, 2018b), pesticide sales and use estimates (EPA
13 1998, 1999, 2002, 2004, 2011, 2017), and the Chemical Data Access Tool (EPA 2014b); the EIA Manufacturer's
14 Energy Consumption Survey (MECS) (EIA 1994, 1997, 2001, 2005, 2010, 2013, 2017); the National Petrochemical &
15 Refiners Association (NPRA 2002); the U.S. Census Bureau (1999, 2004, 2009, 2014); Bank of Canada (2012, 2013,
16 2014, 2016, 2017, 2018, 2019, 2020); Financial Planning Association (2006); INEGI (2006); the United States
17 International Trade Commission (1990 through 2018); Gosselin, Smith, and Hodge (1984); EPA's *Municipal Solid*
18 *Waste (MSW) Facts and Figures* (EPA 2013, 2014a, 2016a, 2018a, 2019); the Rubber Manufacturers' Association
19 (RMA 2009, 2011, 2014, 2016, 2018); the International Institute of Synthetic Rubber Products (IISRP 2000, 2003);
20 the Fiber Economics Bureau (FEB 2001, 2003, 2005, 2007, 2009, 2010, 2011, 2012, 2013); the Independent
21 Chemical Information Service (ICIS 2008, 2016); the EPA Chemical Data Access Tool (CDAT) (EPA 2014b); the
22 American Chemistry Council (ACC 2003 through 2011, 2013, 2014, 2015, 2016, 2017, 2018, 2019, 2020b); and the
23 *Guide to the Business of Chemistry* (ACC 2020a). Specific data sources are listed in full detail in Annex 2.3.

24 **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.⁶⁴ 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).⁶⁵

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. Although emissions from these non-energy uses are reported in the Energy chapter the methodologies used to determine emissions are compatible with the 2006 IPCC Guidelines. 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 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.⁶⁶ The country-

⁶⁴ 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).

⁶⁵ 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*.

⁶⁶ 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.

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. The emissions are reported under the Energy chapter to improve transparency, report a more complete carbon balance and to avoid double counting. 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. For example, only the emissions from the first use of lubricants and waxes are to be reported under the IPPU sector, emissions from use of lubricants in 2-stroke engines and emissions from secondary use of lubricants and waxes in waste incineration with energy recovery are to be reported under the Energy sector. Reporting these non-energy use emissions from only first use of lubricants and waxes under IPPU would involve making artificial adjustments to the non-energy use C carbon balance and could potentially result in double counting of emissions. These artificial adjustments would also be required for asphalt and road oil and solvents (which are captured as part of petrochemical feedstock emissions) and could also potentially result in double counting of emissions. 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, emissions from non-energy 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.

1

2 Uncertainty and Time-Series Consistency

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

9 As noted above, the non-energy use analysis is based on U.S.-specific storage factors for (1) feedstock materials
10 (natural gas, HGL, pentanes plus, naphthas, other oils, still gas, special naphthas, and other industrial coal), (2)
11 asphalt, (3) lubricants, and (4) waxes. For the remaining fuel types (the “other” category in Table 3-21 and Table
12 3-22), the storage factors were taken directly from IPCC (2006), where available, and otherwise assumptions were
13 made based on the potential fate of carbon in the respective NEU products. To characterize uncertainty, five
14 separate analyses were conducted, corresponding to each of the five categories. In all cases, statistical analyses or
15 expert judgments of uncertainty were not available directly from the information sources for all the activity
16 variables; thus, uncertainty estimates were determined using assumptions based on source category knowledge.

17 The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-23 (emissions) and Table
18 3-24 (storage factors). Carbon emitted from non-energy uses of fossil fuels in 2019 was estimated to be between
19 77.4 and 165.1 MMT CO₂ Eq. at a 95 percent confidence level. This indicates a range of 30 percent below to 50
20 percent above the 2019 emission estimate of 110.1 MMT CO₂ Eq. The uncertainty in the emission estimates is a
21 function of uncertainty in both the quantity of fuel used for non-energy purposes and the storage factor.

1 **Table 3-23: Approach 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Non-**
 2 **Energy Uses of Fossil Fuels (MMT CO₂ Eq. and Percent)**

Source	Gas	2019 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	78.2	51.9	136.4	-34%	+74%
Asphalt	CO ₂	0.3	0.1	0.6	-58%	+116%
Lubricants	CO ₂	16.9	13.9	19.6	-18%	+16%
Waxes	CO ₂	0.3	0.2	0.6	-24%	+91%
Other	CO ₂	14.4	2.8	16.7	-80%	+16%
Total	CO₂	110.1	77.4	165.1	-30%	+50%

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.

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

Source	Gas	2019 Storage Factor (%)	Uncertainty Range Relative to Emission Estimate ^a			
			(%)		(% Relative)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Feedstocks	CO ₂	67.4%	53.3%	72.8%	-21%	+8%
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%	47.4%	67.5%	-18%	+17%
Other	CO ₂	11.1%	7.1%	82.5%	-36%	+646%

^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).

5 As shown in Table 3-24, feedstocks and asphalt contribute least to overall storage factor uncertainty on a
 6 percentage basis. Although the feedstocks category—the largest use category in terms of total carbon flows—
 7 appears to have tight confidence limits, this is to some extent an artifact of the way the uncertainty analysis was
 8 structured. As discussed in Annex 2.3, the storage factor for feedstocks is based on an analysis of six fates that
 9 result in long-term storage (e.g., plastics production), and eleven that result in emissions (e.g., volatile organic
 10 compound emissions). Rather than modeling the total uncertainty around all of these fate processes, the current
 11 analysis addresses only the storage fates, and assumes that all C that is not stored is emitted. As the production
 12 statistics that drive the storage values are relatively well-characterized, this approach yields a result that is
 13 probably biased toward understating uncertainty.

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

17 Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990
 18 through 2019 as discussed below. Details on the emission trends through time are described in more detail in the
 19 Methodology section, above.

1 QA/QC and Verification

2 In order to ensure the quality of the emission estimates from non-energy uses of fossil fuels, general (IPCC Tier 1)
3 and category-specific (Tier 2) Quality Assurance/Quality Control (QA/QC) procedures were implemented consistent
4 with the U.S. Inventory QA/QC plan outlined in Annex 8. This effort included a general analysis, as well as portions
5 of a category specific analysis for non-energy uses involving petrochemical feedstocks and for imports and exports.
6 The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and
7 methodology for estimating the fate of C (in terms of storage and emissions) across the various end-uses of fossil
8 C. Emission and storage totals for the different subcategories were compared, and trends across the time series
9 were analyzed to determine whether any corrective actions were needed. Corrective actions were taken to rectify
10 minor errors and to improve the transparency of the calculations, facilitating future QA/QC.

11 For petrochemical import and export data, special attention was paid to NAICS numbers and titles to verify that
12 none had changed or been removed. Import and export totals were compared with 2018 totals as well as their
13 trends across the time series.

14 Some degree of double counting may occur between these estimates of non-energy use of fuels and process
15 emissions from petrochemical production presented in the Industrial Processes and Produce Use (IPPU) sector.
16 This was examined and is not considered to be a significant issue since the non-energy use industrial release data
17 includes different categories of sources than those included in the IPPU sector. Data integration is not feasible at
18 this time as feedstock data from EIA used to estimate non-energy uses of fuels are aggregated by fuel type, rather
19 than disaggregated by both fuel type and particular industries (e.g., petrochemical production) as currently
20 collected through EPA's GHGRP and used for the petrochemical production category.

21 Recalculations Discussion

22 The "miscellaneous products" category reported by EIA includes miscellaneous products that are not reported
23 elsewhere in the EIA data set. The EIA does not have firm data concerning the amounts of various products that
24 are being reported in the "miscellaneous products" category; however, EIA has indicated that recovered sulfur
25 compounds from petroleum and natural gas processing, and potentially also carbon black feedstock could be
26 reported in this category. Recovered sulfur has no carbon content and would not be reported in the NEU
27 calculation or elsewhere in the Inventory. Based on this information, the miscellaneous products category
28 reported by EIA was assumed to be mostly petroleum refinery sulfur compounds that do not contain carbon (EIA
29 2019). Therefore, the carbon content for miscellaneous products was updated to be zero across the time series.

30 In addition, adjustments were made to activity data, carbon content coefficients, and heat contents for HGL for
31 1990 to 2018. Historical HGL activity data from 1990 to 2007 were adjusted to use EIA's Petroleum Supply Annual
32 tables for consistency with the rest of the entire time series (i.e., 2008 to 2019). In previous Inventory reports, HGL
33 activity data from 1990 to 2007 were extracted from the American Petroleum Institute's *Sales of Natural Gas
34 Liquids and Liquefied Refinery Gases*. Thus, the HGL data source for the 1990 to 2007 portion of the time series was
35 updated to align with the HGL activity data used for 2008 to 2019 as well as with data used in other Energy sector
36 source categories (e.g., EIA's *Monthly Energy Review* (EIA 2020a)). In addition, the HGL carbon content coefficient
37 for NEU was updated by separating each fuel out by its natural gas liquid (NGL)⁶⁷ and associated olefin to calculate
38 a more accurate and annually variable factor, and the heat contents for HGL and pentanes plus were updated
39 using updated data from EIA's *Monthly Energy Review* (EIA 2020a).

40 Non-energy use of petroleum coke consumption was adjusted to account for leap years when converting from
41 barrels per day to barrels per year. The carbon factor used to determine the amount of petroleum coke used in
42 several IPPU categories was updated to be consistent with the factors used in the fossil fuel combustion estimates.

⁶⁷ NGL are defined by EIA as "a group of hydrocarbons including ethane, propane, normal butane, isobutane, and natural gasoline. [NGL] generally include natural gas plant liquids and all liquefied refinery gases except olefins" (EIA 2020b).

1 This update impacted the amount of petroleum coke subtracted from non-energy use calculations. Overall, these
2 changes resulted in an average annual decrease of 11.8 MMT CO₂ Eq. (9.5 percent) in carbon emissions from non-
3 energy uses of fossil fuels for the period 1990 through 2018, relative to the previous Inventory. This decrease is
4 primarily due to the removal of miscellaneous products, which previously constituted an average of 8.2 percent of
5 total emissions from 1990 to 2018.

6 **Planned Improvements**

7 There are several future improvements planned:

- 8 • More accurate accounting of C in petrochemical feedstocks. EPA has worked with EIA to determine the
9 cause of input/output discrepancies in the C mass balance contained within the NEU model. In the future,
10 two strategies to reduce or eliminate this discrepancy will continue to be pursued as part of quality
11 control procedures. First, accounting of C in imports and exports will be improved. The import/export
12 adjustment methodology will be examined to ensure that net exports of intermediaries such as ethylene
13 and propylene are fully accounted for. Second, the use of top-down C input calculation in estimating
14 emissions will be reconsidered. Alternative approaches that rely more substantially on the bottom-up C
15 output calculation will be considered instead.
- 16 • Improving the uncertainty analysis. Most of the input parameter distributions are based on professional
17 judgment rather than rigorous statistical characterizations of uncertainty.
- 18 • Better characterizing flows of fossil C. Additional fates may be researched, including the fossil C load in
19 organic chemical wastewaters, plasticizers, adhesives, films, paints, and coatings. There is also a need to
20 further clarify the treatment of fuel additives and backflows (especially methyl tert-butyl ether, MTBE).
- 21 • Reviewing the trends in fossil fuel consumption for non-energy uses. Annual consumption for several fuel
22 types is highly variable across the time series, including industrial coking coal and other petroleum. A
23 better understanding of these trends will be pursued to identify any mischaracterized or misreported fuel
24 consumption for non-energy uses.
- 25 • Updating the average C content of solvents was researched, since the entire time series depends on one
26 year's worth of solvent composition data. The data on C emissions from solvents that were readily
27 available do not provide composition data for all categories of solvent emissions and also have conflicting
28 definitions for volatile organic compounds, the source of emissive C in solvents. Additional sources of
29 solvents data will be investigated in order to update the C content assumptions.
- 30 • Updating the average C content of cleansers (soaps and detergents) was researched; although production
31 and consumption data for cleansers are published every 5 years by the Census Bureau, the composition (C
32 content) of cleansers has not been recently updated. Recently available composition data sources may
33 facilitate updating the average C content for this category.
- 34 • Revising the methodology for consumption, production, and C content of plastics was researched;
35 because of recent changes to the type of data publicly available for plastics, the NEU model for plastics
36 applies data obtained from personal communications. Potential revisions to the plastics methodology to
37 account for the recent changes in published data will be investigated.
- 38 • Although U.S.-specific storage factors have been developed for feedstocks, asphalt, lubricants, and waxes,
39 default values from IPCC are still used for two of the non-energy fuel types (industrial coking coal,
40 distillate oil), and broad assumptions are being used for miscellaneous products and other petroleum.
41 Over the long term, there are plans to improve these storage factors by analyzing C fate similar to those
42 described in Annex 2.3 or deferring to more updated default storage factors from IPCC where available.
- 43 • Reviewing the storage of carbon black across various sectors in the Inventory; in particular, the carbon
44 black abraded and stored in tires.

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 2020a; 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 CO₂. According to the *2006 IPCC Guidelines*, when the CO₂ emitted is of fossil origin, it is counted as a net anthropogenic emission of CO₂ 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 of MSW and scrap tires—plastics, synthetic rubber, synthetic fibers, and carbon black—are of fossil origin. Plastics in the U.S. waste stream are primarily in the form of containers, packaging, and durable goods. Rubber is found in durable goods, such as carpets, and in non-durable goods, such as clothing and footwear. Fibers in 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. Synthetic fibers within scrap tires are not included in this analysis. 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 29.8 million metric tons of MSW were incinerated in 2019 (EPA 2020a). Carbon dioxide emissions from incineration of waste increased 78 percent since 1990, to an estimated 20.2 MMT CO₂ (20,199 kt) in 2019, as the volume of scrap tires and other fossil C-containing materials in waste increased (see Table 3-25 and Table 3-26). While disposal of MSW has decreased over time, the carbon content of that waste has increased, which drives the increase of emissions.

Waste incineration is also a source of CH₄ and N₂O emissions (De Soete 1993; IPCC 2006). Methane emissions from the incineration of waste were estimated to be less than 0.05 MMT CO₂ Eq. (less than 0.5 kt CH₄) in 2019 and have decreased by 11 percent since 1990. Nitrous oxide emissions from the incineration of waste were estimated to be 0.4 MMT CO₂ Eq. (1 kt N₂O) in 2019 and have decreased by 12 percent since 1990. This decrease is driven by the decrease in total MSW incinerated.

Table 3-25: CO₂, CH₄, and N₂O Emissions from the Incineration of Waste (MMT CO₂ Eq.)

Gas/Waste Product	1990	2005	2015	2016	2017	2018	2019
CO ₂	11.2	17.4	21.5	21.8	21.3	20.9	20.2
CH ₄	+	+	+	+	+	+	+
N ₂ O	0.5	0.4	0.4	0.4	0.4	0.4	0.4
Total	11.6	17.8	21.9	22.3	21.7	21.3	20.6

Note: Totals may not sum due to independent rounding.

+ Does not exceed 0.05 MMT CO₂ Eq.

Table 3-26: CO₂, CH₄, and N₂O Emissions from the Incineration of Waste (kt)

Gas/Waste Product	1990	2005	2015	2016	2017	2018	2019
CO ₂	11,183	17,434	21,478	21,830	21,281	20,886	20,199
CH ₄	+	+	+	+	+	+	+
N ₂ O	2	1	1	1	1	1	1

+ Does not exceed 0.5 kt.

Methodology

CO₂ emissions

Carbon dioxide emissions from incineration of MSW are calculated by an IPCC Tier 2 approach applying a country-specific emission factor based on an aggregated carbon content per ton of waste incinerated to the total MSW tonnage of waste incinerated, excluding tires. Tire tonnage and emissions are calculated separately also based on an IPCC Tier 2 approach and added to the total emissions.

The aggregate carbon content per ton of MSW incinerated was based on discard tonnage data of different fossil based waste components including plastics, synthetic fibers, and synthetic rubber 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; EPA 2020a). Fossil carbon content of individual waste components were based on the properties of the materials and the biogenic carbon contents and moisture contents were based on academic research (Staley and Barlaz 2009, Barlaz 1998). The assumption was made that 98 percent of organic carbon is oxidized (which applies to all waste incineration categories for CO₂ emissions) as reported in EPA’s life cycle analysis of greenhouse gas emissions and sinks from management of solid waste (EPA 2006). This oxidation percentage is multiplied by the carbon content of the MSW to estimate the amount of carbon emitted.

To calculate CO₂ emissions from the incineration of tires, tonnage of tires combusted were obtained biannually from U.S. Scrap Tire Management Summary for 2005 through 2019 data (RMA 2020). Information about scrap tire C content 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 in tires. The assumption that 98 percent of organic carbon is oxidized during combustion was multiplied by the carbon stored in tires to estimate the amount of carbon emitted from incineration of tires.

From 1990 to 2005, MSW incineration tonnage was derived from BioCycle’s *State of Garbage in America* (van Haaren et al. 2010). Because BioCycle data include tire tonnages, EPA disaggregated the MSW tonnage to remove tires by subtracting the tire tonnage from the Rubber Manufacturers’ Association information about scrap tire composition (RMA 2020). From 2006 to 2010, MSW incineration tonnage was derived from an average of BioCycle (van Haaren et al. 2010), U.S. Energy Information Administration (EIA) and St. Louis Federal Reserve’s Economic Data (FRED) (EIA 2019), *Advancing Sustainable Materials Management: Facts and Figures Report* EPA (2019a), and the Energy Recovery Council’s *2018 Directory of Waste to Energy Facilities* (ERC 2018). Data from the Energy Recovery Council is also assumed to include tire data, and EPA subtracted the RMA tire tonnage similar to what was done for the BioCycle data. From 2011 to 2019, MSW incineration tonnage is derived from the EPA’s Greenhouse Gas Reporting Program (GHGRP) Subpart C data (EPA 2020b).

Table 3-27 provides data on MSW incinerated (excluding tires) and carbon content of MSW for the total waste stream.

Table 3-27: Municipal Solid Waste Incinerated for Energy (Metric Tons) and Aggregate Carbon Content for CO₂ Emissions

Year	MSW Incinerated (Metric Tons)	Aggregate C-Content for CO ₂ Emissions (kg CO ₂ /metric ton waste)
1990	30,249,096	347
2005	24,027,373	578
2015	26,356,809	694
2016	26,947,616	697
2017	25,921,996	710
2018	26,455,513	683
2019	25,559,171	683

Non-CO₂ emissions

Incineration of waste also results in emissions of CH₄ and N₂O, which are calculated based on an IPCC Tier 1 approach by applying emission factors to the total MSW tonnage of waste incinerated, including tires. The emission factors of N₂O and CH₄ 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). These emission factors consider a certain amount of tire waste in the carbon content, and therefore, MSW tonnages include tires. The same methodology for deriving MSW tonnage across the time series for CO₂ emissions is used here, but tonnage of tires combusted were added based on U.S. Scrap Tire Management Summary (RMA 2018).

Uncertainty and Time-Series Consistency – TO BE UPDATED FOR FINAL REPORT

An Approach 2 Monte Carlo analysis was performed to determine the level of uncertainty surrounding the estimates of CO₂ emissions and N₂O emissions from the incineration of waste (given the very low emissions for CH₄, 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 N₂O 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 CO₂ emissions in 2018 were estimated to be between 8.2 and 14.4 MMT CO₂ 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 CO₂ Eq. Also at a 95 percent confidence level, waste incineration N₂O emissions in 2018 were estimated to be between 0.2 and 1.3 MMT CO₂ Eq. This indicates a range of 51 percent below to 328 percent above the 2018 emission estimate

of 0.3 MMT CO₂ 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 CO₂ and N₂O from the Incineration of Waste (MMT CO₂ Eq. and Percent)

Source	Gas	2018 Emission Estimate (MMT CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			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 ₂ O	0.3	0.2	1.3	-51%	328%

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

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

The historical emissions estimated for this source category have undergone the following revisions for the period 1990 through 2018:

- MSW incineration tonnage:** Data on waste disposed (excluding tires) and waste incinerated were previously derived from BioCycle's *State of Garbage in America* (van Haaren et al. 2010) and Shin (2014) for years 1990 through 2011, i.e., when the data were last updated. For estimates after 2011, data were proxied using the 2011 disposal and incineration tonnages from Shin (2014). EPA revised these tonnages by using BioCycle data until 2005, an average of BioCycle (van Haaren et al. 2010), U.S. Energy Information Administration (EIA) and St. Louis Federal Reserve's Economic Data (FRED) (EIA 2019), *Advancing Sustainable Materials Management: Facts and Figures Report* EPA (2019a), and the Energy Recovery Council's *2018 Directory of Waste to Energy Facilities* (ERC 2018) from 2006 to 2010, and MSW incineration tonnage derived from the EPA's Greenhouse Gas Reporting Program (GHGRP) (EPA 2020b) after 2011.
- Aggregate carbon-content per ton of MSW incinerated:** In previous Inventories, CO₂ emissions from the incineration of waste were calculated by material separately for plastics, synthetic rubber, and synthetic fibers in MSW. Data on the quantity of product disposed are from *Municipal Solid Waste Generation, Recycling, and Disposal in the United States: Facts and Figures* (EPA 2000-2003, 2005-2014); *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). Data on the percent of disposed material that gets incinerated was obtained from the BioCycle data. The amount of incinerated material, obtained from the BioCycle data, was then multiplied by its carbon content to calculate the total amount of carbon emitted. The carbon content of the products was based on the specific material properties.

Information about scrap tire composition and amount combusted was obtained from the Rubber Manufacturers' Association (RMA 2018).

EPA revised the methodology to use an aggregate carbon content per ton of MSW incinerated based on discard and incineration rates of fossil MSW from EPA's *Advancing Sustainable Materials Management: Facts and Figures – Assessing Trends in Material Generation, Recycling and Disposal in the United States* report (EPA 2019). The fossil MSW categories in EPA (2019) include plastics, textiles, and other non-durable and durable goods. Using a combination of moisture content and carbon content for each category of waste, EPA estimated an annual carbon content for each material and calculated the overall carbon content for incinerated waste using a weighted average of carbon contents for each waste category.

As a result of the recalculations, emissions from the incineration of waste increased by 89 percent for 2018 relative to the previous report. On average, emission estimates for the entire time series increased by approximately 54 percent per year.

Planned Improvements

EPA will continue to investigate the accuracy of the MSW mass flow (i.e., tonnage) data including the effect of non-reporters on GHGRP data. EPA will work to harmonize reporting elements in the *Advancing Sustainable Materials Management: Facts and Figures – Assessing Trends in Material Generation, Recycling and Disposal in the United States* report (EPA 2019) and ongoing GHGRP waste incineration data collection to more closely align the two data sets for improving the overall accuracy of these estimates.

Currently, emission estimates for the biomass and biomass-based fuels source category included in this Inventory are limited to woody biomass, ethanol, and biodiesel. EPA will incorporate emissions from biogenic components of MSW to biomass and biomass-based fuels or waste incineration in future Inventory assessments.

3.4 Coal Mining (CRF Source Category 1B1a)

Three types of coal mining-related activities release CH₄ 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 CH₄ emissions (see Table 3-30 and Table 3-31) due to the higher CH₄ content of coal in the deeper underground coal seams. In 2019, 226 underground coal mines and 432 surface mines were operating in the United States (EIA 2020). In recent years, the total number of active coal mines in the United States has declined. In 2019, the United States was the third-largest coal producer in the world (640 MMT), after China (3,693 MMT) and India (769 MMT) (IEA 2020).

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	334,399	789	691,447	1,398	1,025,846
2015	305	278,344	529	534,092	834	812,435
2016	251	228,707	439	431,282	690	659,989
2017	237	247,778	434	454,301	671	702,080
2018	236	249,804	430	435,521	666	685,325
2019	226	242,557	432	397,750	658	640,307

1 Underground mines liberate CH₄ from ventilation systems and from degasification systems. Ventilation systems
 2 pump air through the mine workings to dilute noxious gases and ensure worker safety; these systems can exhaust
 3 significant amounts of CH₄ to the atmosphere in low concentrations. Degasification systems are wells drilled from
 4 the surface or boreholes drilled inside the mine that remove large, often highly concentrated volumes of CH₄
 5 before, during, or after mining. Some mines recover and use CH₄ generated from ventilation and degasification
 6 systems, thereby reducing emissions to the atmosphere.

7 Surface coal mines liberate CH₄ as the overburden is removed and the coal is exposed to the atmosphere. Methane
 8 emissions are normally a function of coal rank (a classification related to the percentage of carbon in the coal) and
 9 depth. Surface coal mines typically produce lower-rank coals and remove less than 250 feet of overburden, so their
 10 level of emissions is much lower than from underground mines.

11 In addition, CH₄ is released during post-mining activities, as the coal is processed, transported, and stored for use.

12 Total CH₄ emissions in 2019 were estimated to be 1,895 kt (47.4 MMT CO₂ Eq.), a decline of approximately 51
 13 percent since 1990 (see Table 3-30 and Table 3-31). In 2019, underground mines accounted for approximately 73
 14 percent of total emissions, surface mines accounted for 13 percent, and post-mining activities accounted for 14
 15 percent. In 2019, total CH₄ emissions from coal mining decreased by approximately 11 percent relative to the
 16 previous year. This decrease was due to a decrease in annual coal production and a decrease in reported annual
 17 ventilation emissions.⁶⁸ The amount of CH₄ recovered and used in 2019 decreased by approximately 17 percent
 18 compared to 2018 levels. In 2019, all but two mines reported lower levels of CH₄ recovered and used compared to
 19 2018 levels.

20 **Table 3-30: CH₄ Emissions from Coal Mining (MMT CO₂ Eq.)**

Activity	1990	2005	2015	2016	2017	2018	2019
Underground (UG) Mining	74.2	42.0	44.9	40.7	40.7	38.9	34.5
Liberated	80.8	59.7	61.2	57.1	58.1	57.7	50.1
Recovered & Used	(6.6)	(17.7)	(16.4)	(16.4)	(17.4)	(18.8)	(15.7)
Surface Mining	10.8	13.2	9.1	7.2	7.7	7.6	6.4
Post-Mining (UG)	9.2	7.6	5.8	4.8	5.3	5.3	5.2
Post-Mining (Surface)	2.3	2.9	2.0	1.6	1.7	1.6	1.4
Total	96.5	65.7	61.8	54.3	55.4	53.4	47.4

21 **Table 3-31: CH₄ Emissions from Coal Mining (kt)**

Activity	1990	2005	2015	2016	2017	2018	2019
Underground (UG) Mining	2,968	1,682	1,796	1,629	1,626	1,556	1,379
Liberated	3,231	2,388	2,450	2,283	2,324	2,307	2,005
Recovered & Used	(263)	(706)	(654)	(654)	(698)	(751)	(627)
Surface Mining	430	527	366	288	310	302	255
Post-Mining (UG)	368	306	231	193	213	212	206
Post-Mining (Surface)	93	114	79	62	67	65	55
Total	3,860	2,629	2,471	2,172	2,216	2,136	1,895

22 Methodology

23 EPA uses an IPCC Tier 3 method for estimating CH₄ emissions from underground coal mining and an IPCC Tier 2
 24 method for estimating CH₄ emissions from surface mining and post-mining activities (for both coal production from

⁶⁸ This indicates low underground mine activity, which is supported by EIA coal production data for 2019 (reduction in production compared to 2018 and 2017).

1 underground mines and surface mines). The methodology for estimating CH₄ emissions from coal mining consists
2 of two steps:

- 3 • Estimate emissions from underground mines. These emissions have two sources: ventilation systems and
4 degasification systems. They are estimated using mine-specific data, then summed to determine total CH₄
5 liberated. The CH₄ recovered and used is then subtracted from this total, resulting in an estimate of net
6 emissions to the atmosphere.
- 7 • Estimate CH₄ emissions from surface mines and post-mining activities. Unlike the methodology for
8 underground mines, which uses mine-specific data, the methodology for estimating emissions from
9 surface mines and post-mining activities consists of multiplying basin-specific coal production by basin-
10 specific gas content and an emission factor.

11 **Step 1: Estimate CH₄ Liberated and CH₄ Emitted from Underground Mines**

12 Underground mines generate CH₄ from ventilation systems and degasification systems. Some mines recover and
13 use the liberated CH₄, thereby reducing emissions to the atmosphere. Total CH₄ emitted from underground mines
14 equals the CH₄ liberated from ventilation systems, plus the CH₄ liberated from degasification systems, minus the
15 CH₄ recovered and used.

16 *Step 1.1: Estimate CH₄ Liberated from Ventilation Systems*

17 To estimate CH₄ liberated from ventilation systems, EPA uses data collected through its Greenhouse Gas Reporting
18 Program (GHGRP)⁶⁹ (Subpart FF, “Underground Coal Mines”), data provided by the U.S. Mine Safety and Health
19 Administration (MSHA) (MSHA 2020), and occasionally data collected from other sources on a site-specific level
20 (e.g., state gas production databases). Since 2011, the nation’s “gassiest” underground coal mines—those that
21 liberate more than 36,500,000 actual cubic feet of CH₄ per year (about 17,525 MT CO₂ Eq.)—have been required to
22 report to EPA’s GHGRP (EPA 2020).⁷⁰ Mines that report to EPA’s GHGRP must report quarterly measurements of
23 CH₄ emissions from ventilation systems; they have the option of recording and reporting their own measurements,
24 or using the measurements taken by MSHA as part of that agency’s quarterly safety inspections of all mines in the
25 United States with detectable CH₄ concentrations.⁷¹

26 Since 2013, ventilation CH₄ emission estimates have been calculated based on both quarterly GHGRP data
27 submitted by underground mines and on quarterly measurement data obtained directly from MSHA. Because not
28 all mines report under EPA’s GHGRP, the emissions of the mines that do not report must be calculated using MSHA
29 data. The MSHA data also serves as a quality assurance tool for validating GHGRP data. For GHGRP data, reported
30 quarterly vent methane emissions (metric tons) are summed for each mine to develop mine-specific annual vent
31 emissions. For MSHA data, the average daily CH₄ emission rate for each mine is determined using the CH₄ total for
32 all data measurement events conducted during the calendar year and total duration of all data measurement
33 events (in days). The calculated average daily CH₄ emissions rate is then multiplied by 365 days to estimate annual
34 ventilation CH₄ emissions for the MSHA dataset.

35 *Step 1.2: Estimate CH₄ Liberated from Degasification Systems*

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 2019, 65 underground coal mines reported to the program.

⁷¹ MSHA records coal mine CH₄ readings with concentrations of greater than 50 ppm (parts per million) CH₄. Readings below this threshold are considered non-detectable.

1 Particularly gassy underground mines also use degasification systems (e.g., wells or boreholes) to remove CH₄
2 before, during, or after mining. This CH₄ can then be collected for use or vented to the atmosphere. Nineteen
3 mines used degasification systems in 2019 and 17 of these mines reported the CH₄ removed through these
4 systems to EPA’s GHGRP under Subpart FF (EPA 2020). Based on the weekly measurements reported to EPA’s
5 GHGRP, degasification data summaries for each mine are added to estimate the CH₄ liberated from degasification
6 systems. Thirteen of the 19 mines with degasification systems had operational CH₄ recovery and use projects (see
7 step 1.3 below).⁷²

8 Degasification data reported to EPA’s GHGRP by underground coal mines is the primary source of data used to
9 develop estimates of CH₄ liberated from degasification systems. Data reported to EPA’s GHGRP were used
10 exclusively to estimate CH₄ liberated from degasification systems at 14 of the 19 mines that used degasification
11 systems in 2019. Data from state gas well production databases were used exclusively for two mines and state gas
12 well production data were used to supplement GHGRP degasification data for the remaining three mines (DMME
13 2020, GSA 2020, and WVGES 2020).

14 For pre-mining wells, cumulative degasification volumes that occur prior to the well being mined through are
15 attributed to the mine in the inventory year in which the well is mined through.⁷³ EPA’s GHGRP does not require
16 gas production from virgin coal seams (coalbed methane) to be reported by coal mines under Subpart FF.⁷⁴ Most
17 pre-mining wells drilled from the surface are considered coalbed methane wells prior to mine-through and
18 associated CH₄ emissions are reported under another subpart of the GHGRP (Subpart W, “Petroleum and Natural
19 Gas Systems”). As a result, GHGRP data must be supplemented to estimate cumulative degasification volumes that
20 occurred prior to well mine-through. There were five mines with degasification systems that include pre-mining
21 wells that were mined through in 2019. For three of these mines, GHGRP data are supplemented with historical
22 data from state gas well production databases (GSA 2020 and WVGES 2020), as well as with mine-specific
23 information regarding the locations and dates on which the pre-mining wells were mined through (JWR 2010; El
24 Paso 2009; ERG 2020). State gas well production data are exclusively used for the remaining two mines (DMME
25 2020 and GSA 2020).

26 *Step 1.3: Estimate CH₄ Recovered from Ventilation and Degasification Systems, and Utilized or*
27 *Destroyed (Emissions Avoided)*

28 Thirteen mines had CH₄ recovery and use projects in place in 2019. Twelve of these projects involved degasification
29 systems and one involved a ventilation air methane abatement project (VAM). Eleven of these mines sold the
30 recovered CH₄ to a pipeline, including one that also used CH₄ to fuel a thermal coal dryer. One mine used
31 recovered CH₄ to heat mine ventilation air (data were unavailable for estimating CH₄ recovery at this mine). One
32 mine destroyed the recovered CH₄ (VAM) using Regenerative Thermal Oxidation (RTO) without energy recovery.

33 The CH₄ recovered and used (or destroyed) at the twelve mines described above for which data were available are
34 estimated using the following methods:

- 35 • EPA’s GHGRP data is exclusively used to estimate the CH₄ recovered and used from seven of the 12 mines
36 that deployed degasification systems in 2019. Based on weekly measurements, the GHGRP degasification
37 destruction data summaries for each mine are added together to estimate the CH₄ recovered and used
38 from degasification systems.

⁷² Several of the mines venting CH₄ 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 CH₄ use is not considered to be a formal recovery and use project.

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 CH₄ liberated from a pre-drainage well is reported under Subpart FF of EPA’s GHGRP.

- 1 • State sales data are used to estimate CH₄ recovered and used from the remaining five mines that
2 deployed degasification systems in 2019 (DMME 2020, GSA 2020). These five mines intersected pre-
3 mining wells in 2019. Supplemental information is used for these mines because estimating CH₄ recovery
4 and use from pre-mining wells requires additional data not reported under Subpart FF of EPA’s GHGRP
5 (see discussion in step 1.2 above) to account for the emissions avoided prior to the well being mined
6 through. The supplemental data came from state gas production databases as well as mine-specific
7 information on the timing of mined-through pre-mining wells.
- 8 • For the single mine that employed VAM for CH₄ recovery and use, the estimates of CH₄ recovered and
9 used are obtained from the mine’s offset verification statement (OVS) submitted to the California Air
10 Resources Board (CARB) (McElroy OVS 2020).

11 Step 2: Estimate CH₄ Emitted from Surface Mines and Post-Mining Activities

12 Mine-specific data are not available for estimating CH₄ emissions from surface coal mines or for post-mining
13 activities. For surface mines, basin-specific coal production obtained from the Energy Information Administration’s
14 *Annual Coal Report* (EIA 2020) is multiplied by basin-specific CH₄ contents (EPA 1996, 2005) and a 150 percent
15 emission factor (to account for CH₄ from over- and under-burden) to estimate CH₄ emissions (King 1994, Saghafi
16 2013). For post-mining activities, basin-specific coal production is multiplied by basin-specific gas contents and a
17 mid-range 32.5 percent emission factor for CH₄ desorption during coal transportation and storage (Creedy 1993).
18 Basin-specific in situ gas content data were compiled from AAPG (1984) and USBM (1986).

19 Uncertainty and Time-Series Consistency

20 A quantitative uncertainty analysis was conducted for the coal mining source category using the IPCC-
21 recommended Approach 2 uncertainty estimation methodology. Because emission estimates from underground
22 ventilation systems were based on actual measurement data from EPA’s GHGRP or from MSHA, uncertainty is
23 relatively low. A degree of imprecision was introduced because the ventilation air measurements used were not
24 continuous but rather quarterly instantaneous readings that were used to determine the average daily emission
25 rate for the quarter. Additionally, the measurement equipment used can be expected to have resulted in an
26 average of 10 percent overestimation of annual CH₄ emissions (Mutmanský & Wang 2000). Equipment
27 measurement uncertainty is applied to both GHGRP and MSHA data.

28 Estimates of CH₄ liberated and recovered by degasification systems are relatively certain for utilized CH₄ because of
29 the availability of EPA’s GHGRP data and gas sales information. Many of the liberation and recovery estimates use
30 data on wells within 100 feet of a mined area. However, uncertainty exists concerning the radius of influence of
31 each well. The number of wells counted, and thus the liberated CH₄ and avoided emissions may vary if the
32 drainage area is found to be larger or smaller than estimated.

33 EPA’s GHGRP requires weekly CH₄ monitoring of mines that report degasification systems, and continuous CH₄
34 monitoring is required for CH₄ utilized on- or off-site. Since 2012, GHGRP data have been used to estimate CH₄
35 emissions from vented degasification wells, reducing the uncertainty associated with prior MSHA estimates used
36 for this sub-source. Beginning in 2013, GHGRP data were also used for determining CH₄ recovery and use at mines
37 without publicly available gas usage or sales records, which has reduced the uncertainty from previous estimation
38 methods that were based on information from coal industry contacts.

39 Beginning in 2015, a small level of uncertainty was introduced by using estimated rather than measured values of
40 recovered CH₄ from two of the mines with degasification systems. An increased level of uncertainty was applied to
41 these two sub-sources, but the change had little impact on the overall uncertainty.

42 Surface mining and post-mining emissions are associated with considerably more uncertainty than underground
43 mines, because of the difficulty in developing accurate emission factors from field measurements. However, since
44 underground emissions constitute the majority of total coal mining emissions, the uncertainty associated with
45 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 CH₄ emissions in 2018 were estimated to be between 43.9 and 59.2 MMT CO₂ 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 CO₂ Eq.

Table 3-32: Approach 2 Quantitative Uncertainty Estimates for CH₄ Emissions from Coal Mining (MMT CO₂ Eq. and Percent)

Source	Gas	2018 Emission Estimate (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

State gas sales production values were updated for one mine for 2011 and 2012, and for 1994 to 2018 for another mine, as part of normal updates. These changes resulted in slightly higher drainage CH₄ emissions and CH₄ emissions avoided from underground mining. The change in both the drainage emissions and emissions avoided is less than 0.5 percent over the 1994 to 2018 time series, compared to the previous Inventory.

Annual coal production numbers were updated for 2001 to 2018 based on revised data from EIA. The previously used EIA coal production numbers were revised, primarily for the Appalachian basins. This update resulted in changes to surface mining and post-surface mining emissions for 2001 to 2018. The change in emissions averaged approximately 9 percent over the 2001 to 2018 time series. The highest change was in 2007 (11.4 percent) and the lowest change was in 2015 (5.3 percent), compared to the previous Inventory.

Planned Improvements

EPA intends to add methods for estimating fugitive CO₂ 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 CH₄ 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 CH₄ that may find its way to surface structures through overburden fractures. As work stops within the mines, CH₄ liberation decreases but it does not stop completely. Following an initial decline, abandoned mines can liberate CH₄ 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 CH₄ 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;
- CH₄ flow capacity of the mine;
- Mine flooding;
- Presence of vent holes; and
- Mine seals.

Annual gross abandoned mine CH₄ emissions ranged from 7.2 to 10.8 MMT CO₂ Eq. from 1990 through 2019, 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 CO₂ Eq.) due to the large number of gassy mine⁷⁵ 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 2019 there were no gassy mine closures. Gross abandoned mine emissions decreased slightly from 8.9 MMT CO₂ Eq. (355 kt CH₄) in 2018 to 8.5 MMT CO₂ Eq. (341 kt CH₄) in 2019 (see Table 3-33 and Table 3-34). Gross emissions are reduced by CH₄ recovered and used at 45 mines, resulting in net emissions in 2019 of 5.9 MMT CO₂ Eq.

Table 3-33: CH₄ Emissions from Abandoned Coal Mines (MMT CO₂ Eq.)

Activity	1990	2005	2014	2015	2016	2017	2018	2019
Abandoned Underground Mines	7.2	8.4	8.7	9.0	9.5	9.2	8.9	8.5
Recovered & Used	0.0	(1.8)	(2.4)	(2.6)	(2.8)	(2.7)	(2.7)	(2.6)
Total	7.2	6.6	6.3	6.4	6.7	6.4	6.2	5.9

Note: Parentheses indicate negative values.

⁷⁵ A mine is considered a “gassy” mine if it emits more than 100 thousand cubic feet of CH₄ per day (100 mcfd).

1 **Table 3-34: CH₄ Emissions from Abandoned Coal Mines (kt)**

Activity	1990	2005	2014	2015	2016	2017	2018	2019
Abandoned Underground Mines	288	334	350	359	380	367	355	341
Recovered & Used	0.0	(70)	(97)	(102)	(112)	(109)	(107)	(104)
Total	288	264	253	256	268	257	247	237

2 Methodology

3 Estimating CH₄ emissions from an abandoned coal mine requires predicting the emissions of a mine from the time
 4 of abandonment through the inventory year of interest. The flow of CH₄ from the coal to the mine void is primarily
 5 dependent on the mine’s emissions when active and the extent to which the mine is flooded or sealed. The CH₄
 6 emission rate before abandonment reflects the gas content of the coal, the rate of coal mining, and the flow
 7 capacity of the mine in much the same way as the initial rate of a water-free conventional gas well reflects the gas
 8 content of the producing formation and the flow capacity of the well. A well or a mine which produces gas from a
 9 coal seam and the surrounding strata will produce less gas through time as the reservoir of gas is depleted.
 10 Depletion of a reservoir will follow a predictable pattern depending on the interplay of a variety of natural physical
 11 conditions imposed on the reservoir. The depletion of a reservoir is commonly modeled by mathematical
 12 equations and mapped as a type curve. Type curves, which are referred to as decline curves, have been developed
 13 for abandoned coal mines. Existing data on abandoned mine emissions through time, although sparse, appear to
 14 fit the hyperbolic type of decline curve used in forecasting production from natural gas wells.

15 In order to estimate CH₄ emissions over time for a given abandoned mine, it is necessary to apply a decline
 16 function, initiated upon abandonment, to that mine. In the analysis, mines were grouped by coal basin with the
 17 assumption that they will generally have the same initial pressures, permeability and isotherm. As CH₄ leaves the
 18 system, the reservoir pressure (Pr) declines as described by the isotherm’s characteristics. The emission rate
 19 declines because the mine pressure (Pw) is essentially constant at atmospheric pressure for a vented mine, and the
 20 productivity index (PI), which is expressed as the flow rate per unit of pressure change, is essentially constant at
 21 the pressures of interest (atmospheric to 30 psia). The CH₄ flow rate is determined by the laws of gas flow through
 22 porous media, such as Darcy’s Law. A rate-time equation can be generated that can be used to predict future
 23 emissions. This decline through time is hyperbolic in nature and can be empirically expressed as:

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

24 where,

- 26 q = Gas flow rate at time t in million cubic feet per day (mmcf/d)
- 27 q_i = Initial gas flow rate at time zero (t₀), mmcf/d
- 28 b = The hyperbolic exponent, dimensionless
- 29 D_i = Initial decline rate, 1/year
- 30 t = Elapsed time from t₀ (years)

31 This equation is applied to mines of various initial emission rates that have similar initial pressures, permeability
 32 and adsorption isotherms (EPA 2004).

33 The decline curves created to model the gas emission rate of coal mines must account for factors that decrease the
 34 rate of emissions after mining activities cease, such as sealing and flooding. Based on field measurement data, it
 35 was assumed that most U.S. mines prone to flooding will become completely flooded within eight years and
 36 therefore will no longer have any measurable CH₄ emissions. Based on this assumption, an average decline rate for
 37 flooded mines was established by fitting a decline curve to emissions from field measurements. An exponential
 38 equation was developed from emissions data measured at eight abandoned mines known to be filling with water
 39 located in two of the five basins. Using a least squares, curve-fitting algorithm, emissions data were matched to
 40 the exponential equation shown below. For this analysis of flooded abandoned mines, there was not enough data

1 to establish basin-specific equations, as was done with the vented, non-flooding mines (EPA 2004). This decline
 2 through time can be empirically expressed as:

$$3 \quad q = q_i e^{(-Dt)}$$

4 where,

- 5 q = Gas flow rate at time t in mmcfd
- 6 q_i = Initial gas flow rate at time zero (t_0), mmcfd
- 7 D = Decline rate, 1/year
- 8 t = Elapsed time from t_0 (years)

9 Seals have an inhibiting effect on the rate of flow of CH₄ into the atmosphere compared to the flow rate that
 10 would exist if the mine had an open vent. The total volume emitted will be the same, but emissions will occur over
 11 a longer period of time. The methodology, therefore, treats the emissions prediction from a sealed mine similarly
 12 to the emissions prediction from a vented mine, but uses a lower initial rate depending on the degree of sealing. A
 13 computational fluid dynamics simulator was used with the conceptual abandoned mine model to predict the
 14 decline curve for inhibited flow. The percent sealed is defined as $100 \times (1 - [\text{initial emissions from sealed mine} /$
 15 $\text{emission rate at abandonment prior to sealing}])$. Significant differences are seen between 50 percent, 80 percent
 16 and 95 percent closure. These decline curves were therefore used as the high, middle, and low values for
 17 emissions from sealed mines (EPA 2004).

18 For active coal mines, those mines producing over 100 thousand cubic feet per day (mcf/d) of CH₄ account for about
 19 98 percent of all CH₄ emissions. This same relationship is assumed for abandoned mines. It was determined that
 20 the 527 abandoned mines closed after 1972 produced CH₄ emissions greater than 100 mcf/d when active. Further,
 21 the status of 304 of the 527 mines (or 58 percent) is known to be either: 1) vented to the atmosphere; 2) sealed to
 22 some degree (either earthen or concrete seals); or, 3) flooded (enough to inhibit CH₄ flow to the atmosphere). The
 23 remaining 42 percent of the mines for which status is unknown were placed in one of these three categories by
 24 applying a probability distribution analysis based on the known status of other mines located in the same coal
 25 basin (EPA 2004). Table 3-35 presents the count of mines by post-abandonment state, based on EPA's probability
 26 distribution analysis.

27 **Table 3-35: Number of Gassy Abandoned Mines Present in U.S. Basins in 2019, Grouped by**
 28 **Class According to Post-Abandonment State**

Basin	Total			Unknown	Total Mines
	Sealed	Vented	Flooded		
Central Appl.	42	26	52	146	266
Illinois	34	3	14	31	82
Northern Appl.	47	22	16	39	124
Warrior Basin	0	0	16	0	16
Western Basins	28	4	2	10	44
Total	151	55	100	226	532

29
 30 Inputs to the decline equation require the average CH₄ emission rate prior to abandonment and the date of
 31 abandonment. Generally, these data are available for mines abandoned after 1971; however, such data are largely
 32 unknown for mines closed before 1972. Information that is readily available, such as coal production by state and
 33 county, is helpful but does not provide enough data to directly employ the methodology used to calculate
 34 emissions from mines abandoned before 1972. It is assumed that pre-1972 mines are governed by the same
 35 physical, geologic, and hydrologic constraints that apply to post-1971 mines; thus, their emissions may be
 36 characterized by the same decline curves.

37 During the 1970s, 78 percent of CH₄ emissions from coal mining came from seventeen counties in seven states.
 38 Mine closure dates were obtained for two states, Colorado and Illinois, for the hundred-year period extending
 39 from 1900 through 1999. The data were used to establish a frequency of mine closure histogram (by decade) and
 40 applied to the other five states with gassy mine closures. As a result, basin-specific decline curve equations were

1 applied to the 145 gassy coal mines estimated to have closed between 1920 and 1971 in the United States,
 2 representing 78 percent of the emissions. State-specific, initial emission rates were used based on average coal
 3 mine CH₄ emissions rates during the 1970s (EPA 2004).

4 Abandoned mine emission estimates are based on all closed mines known to have active mine CH₄ ventilation
 5 emission rates greater than 100 mcfd at the time of abandonment. For example, for 1990 the analysis included 145
 6 mines closed before 1972 and 258 mines closed between 1972 and 1990. Initial emission rates based on MSHA
 7 reports, time of abandonment, and basin-specific decline curves influenced by a number of factors were used to
 8 calculate annual emissions for each mine in the database (MSHA 2020). Coal mine degasification data are not
 9 available for years prior to 1990, thus the initial emission rates used reflect only ventilation emissions for pre-1990
 10 closures. CH₄ degasification amounts were added to the quantity of CH₄ vented to determine the total CH₄
 11 liberation rate for all mines that closed between 1992 and 2019. Since the sample of gassy mines described above
 12 is assumed to account for 78 percent of the pre-1972 and 98 percent of the post-1971 abandoned mine emissions,
 13 the modeled results were multiplied by 1.22 and 1.02 to account for all U.S. abandoned mine emissions.

14 From 1993 through 2019, emission totals were downwardly adjusted to reflect CH₄ emissions avoided from those
 15 abandoned mines with CH₄ recovery and use or destruction systems. The Inventory totals were not adjusted for
 16 abandoned mine CH₄ emission reductions from 1990 through 1992, because no data was reported for abandoned
 17 coal mine CH₄ recovery and use or destruction projects during that time.

18 Uncertainty and Time-Series Consistency

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

24 As discussed above, the parameters for which values must be estimated for each mine in order to predict its
 25 decline curve are: 1) the coal's adsorption isotherm; 2) CH₄ flow capacity as expressed by permeability; and 3)
 26 pressure at abandonment. Because these parameters are not available for each mine, a methodological approach
 27 to estimating emissions was used that generates a probability distribution of potential outcomes based on the
 28 most likely value and the probable range of values for each parameter. The range of values is not meant to capture
 29 the extreme values, but rather values that represent the highest and lowest quartile of the cumulative probability
 30 density function of each parameter. Once the low, mid, and high values are selected, they are applied to a
 31 probability density function.

32 The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-36. Annual abandoned
 33 coal mine CH₄ emissions in 2019 were estimated to be between 4.7 and 7.3 MMT CO₂ Eq. at a 95 percent
 34 confidence level. This indicates a range of 20 percent below to 23 percent above the 2019 emission estimate of 5.9
 35 MMT CO₂ Eq. One of the reasons for the relatively narrow range is that mine-specific data is available for use in the
 36 methodology for mines closed after 1972. Emissions from mines closed prior to 1972 have the largest degree of
 37 uncertainty because no mine-specific CH₄ liberation rates exist.

38 **Table 3-36: Approach 2 Quantitative Uncertainty Estimates for CH₄ Emissions from**
 39 **Abandoned Underground Coal Mines (MMT CO₂ Eq. and Percent)**

Source	Gas	2019 Emission Estimate (MMT CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			Lower Bound	Upper Bound	Lower Bound (%)	Upper Bound (%)
Abandoned Underground Coal Mines	CH ₄	5.9	4.7	7.3	-20%	+23%

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

1 Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990
2 through 2019. Details on the emission trends through time are described in more detail in the Methodology
3 section, above.

4 QA/QC and Verification

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

11 Recalculations Discussion

12 No recalculations were performed for the 1990 through 2018 portion of the time series.

13 3.6 Petroleum Systems (CRF Source Category 14 1B2a)

15 This IPCC category (1B2a) is for fugitive emissions, which per IPCC include emissions from leaks, venting, and
16 flaring. Methane emissions from petroleum systems are primarily associated with onshore and offshore crude oil
17 production, transportation, and refining operations. During these activities, CH₄ is released to the atmosphere as
18 emissions from leaks, venting (including emissions from operational upsets), and flaring. Carbon dioxide emissions
19 from petroleum systems are primarily associated with onshore and offshore crude oil production and refining
20 operations. Note, CO₂ emissions in Petroleum Systems exclude all combustion emissions (e.g., engine combustion)
21 except for flaring CO₂ emissions. All combustion CO₂ emissions (except for flaring) are accounted for in the fossil
22 fuel combustion chapter (see Section 3.1). Emissions of N₂O from petroleum systems are primarily associated with
23 flaring. Total greenhouse gas emissions (CH₄, CO₂, and N₂O) from petroleum systems in 2019 were 83.5 MMT CO₂
24 Eq., an increase of 43 percent from 1990, primarily due to increases in CO₂ emissions. Since 2009, total emissions
25 increased by 55 percent and since 2018, total emissions increased by 11 percent. Total CO₂ emissions from
26 petroleum systems in 2019 were 43.3 MMT CO₂ (43,308 kt CO₂), 4.4 times higher than in 1990. Total CO₂ emissions
27 in 2019 were 3.2 times higher than in 2009 and 18 percent higher than in 2018. Total CH₄ emissions from
28 petroleum systems in 2019 were 40.2 MMT CO₂ Eq. (1,607 kt CH₄), a decrease of 17 percent from 1990. Since
29 2009, total CH₄ emissions decreased by less than 1 percent; and since 2018, CH₄ emissions increased by 4 percent.
30 Total N₂O emissions from petroleum systems in 2019 were 0.04 MMT CO₂ Eq. (0.15 kt N₂O), 2.6 times higher than
31 in 1990, 2.3 times higher than in 2009, and 5 percent higher than in 2018. Since 1990, U.S. oil production has
32 increased by 67 percent. In 2019, production was 129 percent higher than in 2009 and 12 percent higher than in
33 2018.

34 Each year, some estimates in the Inventory are recalculated with improved methods and/or data. These
35 improvements are implemented consistently across the previous Inventory's time series (i.e., 1990 to 2018) to
36 ensure that the trend is accurate. Recalculations in petroleum systems in this year's Inventory include:

- 37 • Incorporation of an estimate for produced water
- 38 • Recalculations due to GHGRP submission revisions

39 The Recalculations Discussion section below provides more details on the updated methods. In addition, several
40 other updates are planned or are under consideration for this year's Inventory, including an update to use the

1 most recent Enverus DrillingInfo data (the well count data used here has not been updated from the previous
2 Inventory due to time constraints) and an update under consideration for onshore production mud degassing.

3 *Exploration.* Exploration includes well drilling, testing, and completions. Exploration accounted for approximately 1
4 percent of total CH₄ emissions (including leaks, vents, and flaring) from petroleum systems in 2019. The
5 predominant sources of CH₄ emissions from exploration are hydraulically fractured oil well completions. Other
6 sources include well testing, well drilling, and well completions without hydraulic fracturing. Since 1990,
7 exploration CH₄ emissions have decreased 91 percent, and while the number of hydraulically fractured wells
8 completed increased by a factor of 2.6, there were decreases in the fraction of such completions without reduced
9 emissions completions (RECs) or flaring (from 90 percent in 1990 to less than 1 percent in 2019). Emissions of CH₄
10 from exploration were highest in 2012, nearly 30 times higher than in 2019; and lowest in 2019. Emissions of CH₄
11 from exploration decreased 28 percent from 2018 to 2019, due to a decrease in hydraulically fractured oil well
12 completions with flaring. Exploration accounts for 5 percent of total emissions (including leaks, vents, and flaring)
13 from petroleum systems in 2019. Emissions of CO₂ from exploration in 2019 were 5.8 times higher than in 1990,
14 and decreased by 27 percent from 2018, due to a decrease in hydraulically fractured oil well completions with
15 flaring. Emissions of CO₂ from exploration were highest in 2014, around 1.6 times higher than in 2019. Exploration
16 accounts for 2 percent of total N₂O emissions from petroleum systems in 2019. Emissions of N₂O from exploration
17 in 2019 are 4.6 times higher than in 1990, and 36 percent lower than in 2018, due to the abovementioned changes
18 in hydraulically fractured oil well completions with flaring.

19 *Production.* Production accounted for 97 percent of total CH₄ emissions (including leaks, vents, and flaring) from
20 petroleum systems in 2019. The predominant sources of emissions from production field operations are pneumatic
21 controllers, offshore oil platforms, gas engines, chemical injection pumps, leaks from oil wellheads, and oil tanks.
22 These six sources together accounted for 81 percent of the CH₄ emissions from production. Since 1990, CH₄
23 emissions from production have decreased by 13 percent due to decreases in emissions from offshore platforms,
24 tanks, and pneumatic controllers. Overall, production segment CH₄ emissions increased by 4 percent from 2018
25 levels due primarily to a decrease in the number of intermittent bleed controllers as use of low bleed controllers
26 grew in 2018. Production emissions account for 84 percent of the total CO₂ emissions (including leaks, vents, and
27 flaring) from petroleum systems in 2019. The principal sources of CO₂ emissions are associated gas flaring, oil tanks
28 with flares, and miscellaneous production flaring. These three sources together account for 98 percent of the CO₂
29 emissions from production. In 2019, CO₂ emissions from production were 5.9 times higher than in 1990, due to
30 increases in flaring emissions from associated gas flaring, tanks, and miscellaneous production flaring. Overall,
31 production segment CO₂ emissions increased by 20 percent from 2018 levels primarily due to an increase in
32 associated gas flaring in the Permian Basin. Production emissions accounted for 64 percent of the total N₂O
33 emissions from petroleum systems in 2019. The principal sources of N₂O emissions are associated gas flaring, oil
34 tanks with flares, and miscellaneous production flaring. In 2019, N₂O emissions from production were 3.1 times
35 higher than in 2009, due primarily to increases in N₂O from associated gas flaring. In 2019, N₂O emissions from
36 production decreased by 6 percent from 2018 levels.

37 *Crude Oil Transportation.* Emissions from crude oil transportation account for a very small percentage of the total
38 emissions (including leaks, vents, and flaring) from petroleum systems and have little impact on the overall
39 emissions. Crude oil transportation activities account for less than 1 percent of total CH₄ emissions from petroleum
40 systems. Emissions from tanks, marine loading, and truck loading operations account for 76 percent of CH₄
41 emissions from crude oil transportation. Since 1990, CH₄ emissions from transportation have increased by 40
42 percent. In 2019, CH₄ emissions from transportation increased by 8 percent from 2018 levels. Crude oil
43 transportation activities account for less than 0.01 percent of total CO₂ emissions from petroleum systems.
44 Emissions from tanks, marine loading, and truck loading operations account for 76 percent of CO₂ emissions from
45 crude oil transportation.

46 *Crude Oil Refining.* Crude oil refining processes and systems account for 2 percent of total fugitive (including leaks,
47 vents, and flaring) CH₄ emissions from petroleum systems. This low share is because most of the CH₄ in crude oil is
48 removed or escapes before the crude oil is delivered to the refineries. There is an insignificant amount of CH₄ in all
49 refined products. Within refineries, flaring accounts for 47 percent of the CH₄ emissions, while uncontrolled
50 blowdowns, delayed cokers, and process vents account for 15, 12, and 10 percent, respectively. Fugitive CH₄

1 emissions from refining of crude oil have increased by 32 percent since 1990, and increased 16 percent from 2018;
 2 however, like the transportation subcategory, this increase has had little effect on the overall emissions of CH₄
 3 from petroleum systems. Crude oil refining processes and systems account for 10 percent of total fugitive
 4 (including leaks, vents, and flaring) CO₂ emissions from petroleum systems. Of the total fugitive CO₂ emissions
 5 from refining, almost all (about 99 percent) of it comes from flaring.⁷⁶ Refinery fugitive CO₂ emissions were 1.5
 6 times higher in 2019 than in 1990 and increased by 34 percent from the 2018 levels, due to an increase in flaring.
 7 Flaring occurring at crude oil refining processes and systems accounts for 34 percent of total fugitive N₂O
 8 emissions from petroleum systems. Refinery fugitive N₂O emissions increased by 61 percent from 1990 to 2019
 9 and increased by 40 percent from 2018 levels.

10 **Table 3-37: Total Greenhouse Gas Emissions (CO₂, CH₄, and N₂O) from Petroleum Systems**
 11 **(MMT CO₂ Eq.)**

Activity	1990	2005	2015	2016	2017	2018	2019
Exploration	3.4	4.9	4.3	1.7	1.9	3.1	2.2
Production	50.8	43.2	66.0	55.9	59.0	67.3	75.1
Transportation	0.2	0.1	0.2	0.2	0.2	0.2	0.2
Crude Refining	4.0	4.5	4.9	4.8	4.6	4.5	5.9
Total	58.3	52.7	75.5	62.7	65.7	75.1	83.5

Note: Totals may not sum due to independent rounding.

12 **Table 3-38: CH₄ Emissions from Petroleum Systems (MMT CO₂ Eq.)**

Activity	1990	2005	2015	2016	2017	2018	2019
Exploration	3.0	4.5	2.1	0.5	0.3	0.4	0.3
Production	44.7	35.2	39.9	39.3	39.5	37.1	38.8
Pneumatic Controllers	19.3	17.8	20.0	21.0	21.3	18.6	18.9
Offshore Production	9.3	6.5	5.5	5.1	5.1	5.0	5.0
Equipment Leaks	2.2	2.2	2.7	2.6	2.6	2.5	2.5
Gas Engines	2.1	1.7	2.3	2.2	2.2	2.3	2.3
Chemical Injection Pumps	1.2	1.7	2.2	2.1	2.1	2.0	2.0
Tanks	5.5	1.5	1.7	1.9	1.5	1.5	1.5
Other Sources	5.0	3.8	5.4	4.3	4.7	5.3	6.5
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	0.9
Total	48.5	40.6	43.0	40.8	40.9	38.5	40.2

Note: Totals may not sum due to independent rounding.

⁷⁶ Petroleum Systems includes fugitive emissions (leaks, venting, and flaring). In many industries, including petroleum refineries, the largest source of onsite CO₂ emissions is often fossil fuel combustion, which is covered in section 3.1 of this chapter.

1 **Table 3-39: CH₄ Emissions from Petroleum Systems (kt CH₄)**

Activity	1990	2005	2015	2016	2017	2018	2019
Exploration	121	181	84	19	14	15	11
Production	1,786	1,407	1,594	1,571	1,581	1,486	1,551
Pneumatic Controllers	772	710	801	839	853	742	756
Offshore Production	374	261	221	206	205	199	201
Equipment Leaks	88	87	108	104	102	101	101
Gas Engines	86	70	93	90	89	91	94
Chemical Injection Pumps	49	68	87	84	82	81	81
Tanks	219	60	68	76	62	59	60
Other Sources	198	150	217	173	188	212	258
Crude Oil Transportation	7	5	8	8	8	8	9
Refining	27	31	33	33	33	31	36
Total	1,941	1,624	1,720	1,631	1,635	1,540	1,607

Note: Totals may not sum due to independent rounding.

2 **Table 3-40: CO₂ Emissions from Petroleum Systems (MMT CO₂)**

Activity	1990	2005	2015	2016	2017	2018	2019
Exploration	0.3	0.4	2.2	1.2	1.6	2.7	2.0
Production	6.1	8.0	26.1	16.6	19.5	30.1	36.3
Transportation	+	+	+	+	+	+	+
Crude Refining	3.3	3.7	4.1	4.0	3.7	3.7	5.0
Total	9.7	12.1	32.4	21.9	24.8	36.6	43.3

Note: Totals may not sum due to independent rounding.

3 **Table 3-41: CO₂ Emissions from Petroleum Systems (kt CO₂)**

Activity	1990	2005	2015	2016	2017	2018	2019
Exploration	338	354	2,228	1,232	1,590	2,705	1,962
Production	6,109	7,988	26,139	16,631	19,508	30,147	36,326
Transportation	0.9	0.7	1.2	1.1	1.1	1.2	1.3
Crude Refining	3,284	3,728	4,067	3,991	3,714	3,735	5,019
Total	9,732	12,071	32,434	21,855	24,813	36,588	43,308

Note: Totals may not sum due to independent rounding.

4 **Table 3-42: N₂O Emissions from Petroleum Systems (Metric Tons CO₂ Eq.)**

Activity	1990	2005	2015	2016	2017	2018	2019
Exploration	176	181	1,142	627	696	1,275	811
Production	7,502	8,043	20,270	15,061	15,7338	29,332	27,715
Transportation	NE						
Crude Refining	9,138	10,372	11,656	11,575	10,796	10,557	14,749
Total	16,816	18,596	33,068	27,263	27,230	41,164	43,275

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

5 **Table 3-43: N₂O Emissions from Petroleum Systems (Metric Tons N₂O)**

Activity	1990	2005	2015	2016	2017	2018	2019
Exploration	0.6	0.6	3.8	2.1	2.3	4.3	2.7
Production	25.2	27.0	68.0	50.5	52.8	98.4	93.0
Transportation	NE						

Crude Refining	30.7	34.8	39.1	38.8	36.2	35.4	49.5
Total	56.4	62.4	111.0	91.5	91.4	138.1	145.2

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, 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). Certain sources within petroleum refineries are developed with a Tier 3 approach (i.e., all refineries in the nation report emissions data for these sources to the GHGRP, and they are included in the estimates here). Other estimates are developed with a Tier 2 approach. Tier 1 approaches are not used.

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 2020).

Emission factors for hydraulically fractured (HF) oil well completions and workovers (in four control categories) were developed using EPA's 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 CO₂ 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. For

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

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

3 For the exploration and production segments, in general, CO₂ emissions for each source were estimated with
4 GHGRP data or by multiplying CO₂ content factors by the corresponding CH₄ data, as the CO₂ content of gas relates
5 to its CH₄ content. Sources with CO₂ emission estimates calculated using GHGRP data include HF completions and
6 workovers, associated gas venting and flaring, tanks, well testing, pneumatic controllers, chemical injection pumps,
7 miscellaneous production flaring, and certain offshore production facilities (those located off the coasts of
8 California and Alaska). For these sources, CO₂ was calculated using the same methods as used for CH₄. Carbon
9 dioxide emission factors for offshore oil production in the Gulf of Mexico were derived using data from BOEM,
10 following the same methods as used for CH₄ estimates. For other sources, the production field operations emission
11 factors for CO₂ are generally estimated by multiplying the CH₄ emission factors by a conversion factor, which is the
12 ratio of CO₂ content and CH₄ content in produced associated gas.

13 For the exploration and production segments, N₂O emissions were estimated for flaring sources using GHGRP or
14 BOEM OGOR-B data and the same method used for CO₂. Sources with N₂O emissions in the exploration segment
15 include well testing and HF completions with flaring. Sources with N₂O emissions in the production segment
16 include associated gas flaring, tank flaring, miscellaneous production flaring, HF workovers with flaring, and flaring
17 from offshore production sources.

18 For crude oil transportation, emission factors for CH₄ were largely developed using data from EPA (1997), API
19 (1992), and EPA (1999). Emission factors for CO₂ were estimated by multiplying the CH₄ emission factors by a
20 conversion factor, which is the ratio of CO₂ content and CH₄ content in whole crude post-separator.

21 For petroleum refining activities, year-specific emissions from 2010 forward were directly obtained from EPA's
22 GHGRP. All U.S. refineries have been required to report CH₄, CO₂, and N₂O emissions for all major activities starting
23 with emissions that occurred in 2010. The reported total CH₄, CO₂, and N₂O emissions for each activity was used
24 for the emissions in each year from 2010 forward. To estimate emissions for 1990 to 2009, the 2010 to 2013
25 emissions data from GHGRP along with the refinery feed data for 2010 to 2013 were used to derive CH₄ and CO₂
26 emission factors (i.e., sum of activity emissions/sum of refinery feed) and 2010 to 2017 data were used to derive
27 N₂O emission factors; these emission factors were then applied to the annual refinery feed in years 1990 to 2009.
28 GHGRP delayed coker CH₄ emissions for 2010 through 2017 were increased using the ratio of certain reported
29 emissions for 2018 to 2017, to account for a more accurate GHGRP calculation methodology that was
30 implemented starting in reporting year 2018.

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

32 *Activity Data.* References for activity data include DrillingInfo data (Enverus DrillingInfo 2019), Energy Information
33 Administration (EIA) reports, *Methane Emissions from the Natural Gas Industry by the Gas Research Institute and*
34 *EPA* (EPA/GRI 1996), *Estimates of Methane Emissions from the U.S. Oil Industry* (EPA 1999), consensus of industry
35 peer review panels, BOEM reports, the Oil & Gas Journal, the Interstate Oil and Gas Compact Commission, the
36 United States Army Corps of Engineers, and analysis of GHGRP data (EPA 2020).

37 For many sources, complete activity data were not available for all years of the time series. In such cases, one of
38 three approaches was employed to estimate values, consistent with IPCC good practice. Where appropriate, the
39 activity data were calculated from related statistics using ratios developed based on EPA/GRI 1996 and/or GHGRP
40 data. In some cases, activity data are developed by interpolating between recent data points (such as from GHGRP)
41 and earlier data points, such as from EPA/GRI 1996. Lastly, in limited instances the previous year's data were used
42 if current year data were not yet available.

43 A complete list of references for emission factors and activity data by emission source is provided in Annex 3.5. The
44 U.S. reports data to the UNFCCC using this Inventory report along with Common Reporting Format (CRF) tables.
45 This note is provided for those reviewing the CRF tables: The notation key "IE" is used for CO₂ and CH₄ emissions
46 from venting and flaring in CRF table 1.B.2. Disaggregating flaring and venting estimates across the Inventory
47 would involve the application of assumptions and could result in inconsistent reporting and, potentially, decreased
48 transparency. Data availability varies across segments within oil and gas activities systems, and emission factor

1 data available for activities that include flaring can include emissions from multiple sources (flaring, venting and
 2 leaks).

3 **Uncertainty and Time-Series Consistency - TO BE UPDATED** 4 **FOR FINAL INVENTORY REPORT**

5 EPA conducted a quantitative uncertainty analysis using the IPCC Approach 2 methodology (Monte Carlo
 6 Simulation technique) to characterize uncertainty for petroleum systems. For more information on the approach,
 7 please see the memorandum Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2016: Natural Gas and
 8 Petroleum Systems Uncertainty Estimates (2018 Uncertainty Memo).⁷⁸

9 EPA used Microsoft Excel's @RISK add-in tool to estimate the 95 percent confidence bound around methane
 10 emissions from petroleum systems for the current Inventory, then applied the calculated bounds to both CH₄ and
 11 CO₂ emissions estimates. Uncertainty estimates for N₂O were not developed given the minor contribution of N₂O
 12 to emission totals. For the analysis, EPA focused on the six highest methane-emitting sources for the year 2018,
 13 which together emitted 75 percent of methane from petroleum systems in 2018, and extrapolated the estimated
 14 uncertainty for the remaining sources. The @RISK add-in provides for the specification of probability density
 15 functions (PDFs) for key variables within a computational structure that mirrors the calculation of the inventory
 16 estimate. The IPCC guidance notes that in using this method, "some uncertainties that are not addressed by
 17 statistical means may exist, including those arising from omissions or double counting, or other conceptual errors,
 18 or from incomplete understanding of the processes that may lead to inaccuracies in estimates developed from
 19 models." As a result, the understanding of the uncertainty of emission estimates for this category evolves and
 20 improves as the underlying methodologies and datasets improve. The uncertainty bounds reported below only
 21 reflect those uncertainties that EPA has been able to quantify and do not incorporate considerations such as
 22 modeling uncertainty, data representativeness, measurement errors, misreporting or misclassification.

23 The results presented below provide the 95 percent confidence bound within which actual emissions from this
 24 source category are likely to fall for the year 2018, using the recommended IPCC methodology. The results of the
 25 Approach 2 uncertainty analysis are summarized in Table 3-44Table 3-44. Petroleum systems CH₄ emissions in
 26 2018 were estimated to be between 25.0 and 48.4 MMT CO₂ Eq., while CO₂ emissions were estimated to be
 27 between 25.4 and 49.3 MMT CO₂ Eq. at a 95 percent confidence level. Uncertainty bounds for other years of the
 28 time series have not been calculated, but uncertainty is expected to vary over the time series. For example, years
 29 where many emission sources are calculated with interpolated data would likely have higher uncertainty than
 30 years with predominantly year-specific data.

31 **Table 3-44: Approach 2 Quantitative Uncertainty Estimates for CH₄ and CO₂ Emissions from**
 32 **Petroleum Systems (MMT CO₂ 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 CH₄ 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 CO₂ emissions was not performed. The relative uncertainty estimated (expressed as a percent) from the CH₄ uncertainty analysis was applied to the point estimate of petroleum systems CO₂

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

1 EPA's GHGRP data, available starting in 2010 for refineries and in 2011 for other sources, have improved estimates
2 of emissions from petroleum systems. Many of the previously available datasets were collected in the 1990s. To
3 develop a consistent time series for sources with new data, EPA reviewed available information on factors that
4 may have resulted in changes over the time series (e.g., regulations, voluntary actions) and requested stakeholder
5 feedback on trends as well. For most sources, EPA developed annual data for 1993 through 2009 or 2014 by
6 interpolating activity data or emission factors or both between 1992 (when GRI/EPA data are available) and 2010
7 or 2015 data points. Information on time-series consistency for sources updated in this year's Inventory can be
8 found in the Recalculations Discussion below, with additional detail provided in supporting memos (relevant
9 memos are cited in the Recalculations Discussion). For information on other sources, please see the Methodology
10 Discussion above and Annex 3.5. Methodological recalculations were applied to the entire time series to ensure
11 time-series consistency from 1990 through 2019. Details on the emission trends through time are described in
12 more detail in the Methodology section, above.

13 QA/QC and Verification Discussion

14 The petroleum systems emission estimates in the Inventory are continually being reviewed and assessed to
15 determine whether emission factors and activity factors accurately reflect current industry practices. A QA/QC
16 analysis was performed for data gathering and input, documentation, and calculation. QA/QC checks are
17 consistently conducted to minimize human error in the model calculations. EPA performs a thorough review of
18 information associated with new studies, GHGRP data, regulations, public webcasts, and the Natural Gas STAR
19 Program to assess whether the assumptions in the Inventory are consistent with current industry practices. EPA
20 has a multi-step data verification process for GHGRP data, including automatic checks during data-entry, statistical
21 analyses on completed reports, and staff review of the reported data. Based on the results of the verification
22 process, EPA follows up with facilities to resolve mistakes that may have occurred.⁷⁹

23 As in previous years, EPA conducted early engagement and communication with stakeholders on updates prior to
24 public review. EPA held stakeholder webinars on greenhouse gas data for oil and gas in September and November
25 of 2020. EPA released memos detailing updates under consideration and requesting stakeholder feedback.
26 Stakeholder feedback received through these processes is discussed in the Recalculations Discussion and Planned
27 Improvements sections below.

28 In recent years, several studies have measured emissions at the source level and at the national or regional level
29 and calculated emission estimates that may differ from the Inventory. There are a variety of potential uses of data
30 from new studies, including replacing a previous estimate or factor, verifying or QA of an existing estimate or
31 factor, and identifying areas for updates. In general, there are two major types of studies related to oil and gas
32 greenhouse gas data: studies that focus on measurement or quantification of emissions from specific activities,
33 processes, and equipment, and studies that use tools such as inverse modeling to estimate the level of overall
34 emissions needed to account for measured atmospheric concentrations of greenhouse gases at various scales. The
35 first type of study can lead to direct improvements to or verification of Inventory estimates. In the past few years,
36 EPA has reviewed, and in many cases, incorporated data from these data sources. The second type of study can
37 provide general indications on potential over- and under-estimates. A key challenge in using these types of studies
38 to assess Inventory results is having a relevant basis for comparison (i.e., the independent study should assess data
39 from the Inventory and not another data set, such as the Emissions Database for Global Atmospheric Research, or
40 "EDGAR"). In an effort to improve the ability to compare the national-level Inventory with measurement results
41 that may be at other scales, a team at Harvard University along with EPA and other coauthors developed a gridded
42 inventory of U.S. anthropogenic methane emissions with 0.1 degree x 0.1 degree spatial resolution, monthly

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

1 temporal resolution, and detailed scale-dependent error characterization.⁸⁰ The gridded methane inventory is
2 designed to be consistent with the U.S. EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2014*
3 estimates for the year 2012, which presents national totals.⁸¹

4 As discussed above, refinery emissions are quantified by using the total emissions reported to GHGRP for the
5 refinery emission categories included in Petroleum Systems. Subpart Y has provisions that refineries are not
6 required to report under Subpart Y if their emissions fall below certain thresholds. Each year, a review is conducted
7 to determine whether an adjustment is needed to the Inventory emissions to include emissions from refineries
8 that stopped reporting to the GHGRP. The 2018 GHGRP data indicates that 2 refineries stopped reporting in 2018
9 (i.e., 2017 is the last reported year). One of them permanently shut down towards the end of 2017 and the other
10 one did not report in 2018 due to a merger. Based on this assessment, cessation of reporting does not impact the
11 completeness of data for 2018 refinery emissions and therefore no adjustment has been made to these estimates
12 for the Inventory. This check will be completed on the RY2019 data for the final 1990 to 2019 Inventory.

13 Recalculations Discussion

14 EPA received information and data related to the emission estimates through GHGRP reporting, the annual
15 Inventory formal public notice periods, stakeholder feedback on updates under consideration, and new studies. In
16 September 2020, EPA released a draft memorandum that discussed changes under consideration to estimate
17 emissions from produced water and requested stakeholder feedback on those changes.⁸² The EPA memorandum
18 *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2019: Update Under Consideration for Produced Water*
19 *Emissions (Produced Water memo)* is cited below.

20 EPA thoroughly evaluated relevant information available and made updates to include of an estimate for produced
21 water emissions. In addition, certain sources did not undergo methodological updates, but CH₄ and/or CO₂
22 emissions changed by greater than 0.05 MMT CO₂ Eq., comparing the previous estimate for 2018 to the current
23 (recalculated) estimate for 2018 (the emissions changes were mostly due to GHGRP data submission
24 revisions). These sources are discussed below and include hydraulically fractured oil well completions, associated
25 gas flaring, miscellaneous production flaring, production storage tanks, and pneumatic controllers. Note that
26 additional changes will occur in the final Inventory due to the planned incorporation of updated Enverus well data,
27 and other changes could occur due to potential updates to include mud degassing and potential revisions to
28 existing methods based on stakeholder feedback.

29 The combined impact of revisions to 2018 petroleum systems CH₄ emission estimates, compared to the previous
30 Inventory, is an increase from 36.2 to 38.5 MMT CO₂ Eq. (2.3 MMT CO₂ Eq., or 6 percent). The recalculations
31 resulted in an average increase in CH₄ emission estimates across the 1990 through 2018 time series, compared to
32 the previous Inventory, of 2.0 MMT CO₂ Eq., or 5 percent, with the largest increase being in the estimate for 2015
33 (2.5 MMT CO₂ Eq. or 6 percent).

34 The combined impact of revisions to 2018 petroleum systems CO₂ emission estimates, compared to the previous
35 Inventory, is a decrease from 36.8 to 36.6 MMT CO₂ (0.2 MMT CO₂, or less than 1 percent). The recalculations
36 resulted in an average decrease in emission estimates across the 1990 through 2018 time series, compared to the
37 previous Inventory, of 0.1 MMT CO₂ Eq., or 0.4 percent with the largest changes being for 2016 (1.1 MMT CO₂ or 5
38 percent) primarily due to the recalculations for flaring from tanks.

39 The combined impact of revisions to 2018 petroleum systems N₂O emission estimates, compared to the previous
40 Inventory, is a decrease of 0.03 MMT CO₂, Eq. or 42 percent. The recalculations resulted in an average decrease in

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>>.

⁸² Stakeholder materials including draft memoranda for the current (i.e., 1990 to 2019) Inventory are available at
<<https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems>>.

1 emission estimates across the 1990 through 2018 time series, compared to the previous Inventory, of 0.001 MMT
 2 CO₂ Eq., or 2 percent.

3 In Table 3-45 and Table 3-46 below are categories in Petroleum Systems with updated methodologies or with
 4 recalculations resulting in a change of greater than 0.05 MMT CO₂ Eq., comparing the previous estimate for 2018
 5 to the current (recalculated) estimate for 2018. For more information, please see the discussion below.

6 **Table 3-45: Recalculations of CO₂ in Petroleum Systems (MMT CO₂)**

Segment/Source	<i>Previous Estimate Year 2018, 2020 Inventory</i>	<i>Current Estimate Year 2018, 2021 Inventory</i>	<i>Current Estimate Year 2019, 2021 Inventory</i>
Exploration	2.8	2.7	2.0
HF Oil Well Completions	2.7	2.7	2.0
Production	30.3	30.1	36.3
Produced Water	NE	NE	NE
Tanks	6.4	6.3	6.1
Associated Gas Flaring	19.0	19.0	22.4
Miscellaneous Flaring	4.2	4.1	7.1
Transportation	+	+	+
Refining	3.7	3.7	5.0
Petroleum Systems Total	36.8	36.6	43.3

7 + Does not exceed 0.05 MMT CO₂.

8 NE (Not Estimated)

9

10 **Table 3-46: Recalculations of CH₄ in Petroleum Systems (MMT CO₂ Eq.)**

Segment/Source	<i>Previous Estimate Year 2018, 2020 Inventory</i>	<i>Current Estimate Year 2018, 2021 Inventory</i>	<i>Current Estimate Year 2019, 2021 Inventory</i>
Exploration	0.4	0.4	0.3
Production	34.9	37.1	38.8
Produced Water	NE	1.9	1.9
Pneumatic Controllers	18.7	18.6	18.9
Associated Gas Flaring	1.3	1.7	1.8
Miscellaneous Flaring	0.4	0.3	0.5
Transportation	0.2	0.2	0.2
Refining	0.8	0.8	0.9
Petroleum Systems Total	36.2	38.5	40.2

11 NE (Not Estimated)

12 + Does not exceed 0.05 MMT CO₂ Eq.

13

14 Exploration

15 *HF Oil Well Completions (Recalculation with Updated Data)*

16 HF oil well completion CO₂ emissions decreased by an average of less than 0.5 percent across the time series and
 17 decreased by 2 percent in 2018, compared the to the previous Inventory. The emissions changes were due to
 18 GHGRP data submission revisions.

1 **Table 3-47: HF Oil Well Completions National CO₂ Emissions (kt CO₂)**

Source	1990	2005	2015	2016	2017	2018	2019
HF Completions: Non-REC with Venting	2.5	4.0	1.4	0.2	0.2	+	+
HF Completions: Non-REC with Flaring	89	139	446	252	368	534	749
HF Completions: REC with Venting	0.0	0.0	0.2	0.1	0.1	0.1	0.1
HF Completions: REC with Flaring	0.0	0.0	1,518	940	1,184	2,137	1,209
Total Emissions	92	143	1,965	1,191	1,552	2,671	1,958
<i>Previous Estimate</i>	92	143	1,966	1,192	1,529	2,730	NA

+ Does not exceed 0.05 kt CO₂.

NA (Not Applicable)

2 **Production**

3 *Produced Water (Methodological Update)*

4 EPA developed a new estimate for produced water from oil wells. Previous Inventories did not include emissions
 5 from produced water from oil wells. EPA’s considerations for this source are documented in the *Produced Water*
 6 Memo.⁸³ Produced water quantities (i.e., bbl) were obtained for the 29 largest oil-producing states as described
 7 below:

- 8 • Produced water quantities were obtained from Enverus DrillingInfo data for 22 states (i.e., AK, AL, AR, AZ,
 9 CA, CO, FL, LA, MI, MO, MS, MT, ND, NE, NM, NV, NY, SD, TX, UT, VA, and WY) (Enverus DrillingInfo 2019)
- 10 • Produced water quantities were provided by 4 states – KS (Kansas Department of Health and Environment
 11 2020), OH (Ohio Environmental Protection Agency 2020), OK (Oklahoma Department of Environmental
 12 Quality 2020), and PA (Pennsylvania Department of Environmental Protection 2020)
- 13 • Produced water quantities were estimated for 3 states (IL, IN, and WV) using produced water production
 14 ratios estimated using 2011 Enverus DrillingInfo data combined with EIA state-level oil production
 15 quantities (IL and IN [1990-1999]) (EIA 2020), state-provided oil production quantities (IN [2000-2019])
 16 (Indiana Department of Natural Resources 2020), and Enverus DrillingInfo data (WV)

17 Based upon findings of the CenSARA emissions inventory (CenSARA 2012), EPA assumed that 73 percent of the
 18 produced water was from low pressure oil wells (i.e., wells requiring artificial lifts) and that 27 percent of the
 19 produced water was from regular pressure oil wells (i.e., wells not requiring artificial lifts).. EPA applied emission
 20 factors unique to low pressure and regular pressure oil wells, obtained from the Production Module of the 2017 Oil
 21 and Gas Tool. Produced water CH₄ emissions average 74,000 mt CH₄, over the 1990 to 2018 time series.

22 EPA received comments on the *Produced Water* Memo and is continues to seek feedback on the fraction of
 23 produced water that is routed to tanks and undergoes flashing, and the fraction of these tanks that have controls
 24 and how such controls should be taken into account.

25 **Table 3-48: Produced Water National CH₄ Emissions (Metric Tons CH₄)**

Source	1990	2005	2015	2016	2017	2018	2019
Low Pressure Oil Wells	20,569	14,235	18,790	17,666	17,990	16,857	16,857
Regular Pressure Oil Wells	72,156	49,938	65,917	61,975	63,112	59,138	59,138
Total	92,725	64,173	84,707	79,641	81,102	75,995	75,995
<i>Previous Estimate</i>	NA						

NA (Not Applicable)

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

1 *Tanks (Recalculation with Updated Data)*

2 Tank CO₂ emissions estimates increased by an average of 2 percent across the 1990 to 2018 time series, compared
3 to the previous inventory. This change was due to GHGRP submission revisions.

4 **Table 3-49: Tanks National CO₂ Emissions (kt CO₂)**

Source	1990	2005	2015	2016	2017	2018	2019
Large Tanks w/Flares	0	2,451	7,074	4,489	4,298	6,219	6,037
Large Tanks w/VRU	0	5	14	3	4	4	7
Large Tanks w/o Control	24	6	6	5	5	4	5
Small Tanks w/Flares	0	2	7	13	11	8	10
Small Tanks w/o Flares	6	3	5	4	4	4	4
Malfunctioning Separator Dump Valves	86	50	104	32	43	39	34
Total Emissions	116	2,517	7,209	4,546	4,364	6,278	6,098
<i>Previous Estimate</i>	46	2,641	7,584	5,913	4,413	6,369	NA

NA (Not Applicable)

5 *Pneumatic Controllers (Recalculation with Updated Data)*

6 Pneumatic controller CH₄ emission estimates increased by an average of 0.7 percent across the 1990 to 2018 time
7 series, compared to the previous Inventory. This change was due to GHGRP submission revisions.

8 **Table 3-50: Pneumatic Controller National CH₄ Emissions (Metric Tons CH₄)**

Source	1990	2005	2015	2016	2017	2018	2019
Low Bleed	722,968	423,884	78,424	83,187	60,808	48,451	53,821
High Bleed	49,343	44,418	25,465	17,476	19,497	30,476	36,863
Intermittent Bleed	0	241,861	696,636	738,006	772,298	663,251	665,665
Total Emissions	772,311	710,164	800,525	838,668	852,603	742,178	756,349
<i>Previous Estimate</i>	772,311	704,401	789,484	822,989	850,624	734,824	NA

NA (Not Applicable)

9 *Associated Gas Flaring (Recalculation with Updated Data)*

10 Associated gas flaring CO₂ emission estimates increased by an average of 1 percent across the time series in the
11 current Inventory, compared to the previous Inventory. This change was due to GHGRP submission revisions. The
12 changes in CO₂ emissions for 2018 (the year with the largest change) were mainly driven by Williston Basin data.

13 **Table 3-51: Associated Gas Flaring National CO₂ Emissions (kt CO₂)**

Source	1990	2005	2015	2016	2017	2018	2019
220 - Gulf Coast Basin (LA, TX)	234	127	673	404	738	632	560
360 - Anadarko Basin	108	66	239	1	64	74	16
395 - Williston Basin	984	1,261	8,562	6,087	6,909	11,056	14,695
430 - Permian Basin	2,983	2,046	4,443	2,246	3,161	6,524	5,578
"Other" Basins	932	503	551	326	396	700	1,554
Total Emissions	5,240	4,002	14,468	9,065	11,268	18,986	22,403
<i>220 - Gulf Coast Basin (LA, TX)</i>	234	127	631	673	404	740	NA
<i>360 - Anadarko Basin</i>	108	65	230	238	2	57	NA
<i>395 - Williston Basin</i>	966	1,239	7,799	8,412	5,838	6,530	NA
<i>430 - Permian Basin</i>	2,983	2,046	3,869	4,443	2,246	3,148	NA
<i>"Other" Basins</i>	925	499	520	544	326	414	NA
<i>Previous Estimate</i>	5,217	3,977	13,050	14,311	8,815	10,889	NA

NA (Not Applicable)

1 Associated gas flaring CH₄ emission estimates increased by an average of 2 percent across the time series in the
 2 current Inventory, compared to the previous inventory. The CH₄ estimates increased by 25 percent in 2018,
 3 primarily due to Williston Basin data. These changes were due to GHGRP submission revisions.

4 **Table 3-52 Associated Gas Flaring National CH₄ Emissions (MT CH₄)**

Source	1990	2005	2015	2016	2017	2018	2019
220 - Gulf Coast Basin (LA, TX)	922	500	2,659	1,572	2,910	2,407	2,519
360 - Anadarko Basin	473	286	1,041	4	274	324	76
395 - Williston Basin	2,921	3,745	25,422	16,939	20,707	37,469	42,966
430 - Permian Basin	11,816	8,104	17,596	8,913	12,994	25,541	21,043
"Other" Basins	4,310	2,326	2,552	1,201	1,320	2,111	5,504
Total Emissions	20,442	14,961	49,269	28,630	38,206	66,852	72,107
<i>220 - Gulf Coast Basin (LA, TX)</i>	<i>922</i>	<i>500</i>	<i>2,659</i>	<i>1,572</i>	<i>2,918</i>	<i>2,779</i>	<i>NA</i>
<i>360 - Anadarko Basin</i>	<i>471</i>	<i>285</i>	<i>1,038</i>	<i>7</i>	<i>252</i>	<i>190</i>	<i>NA</i>
<i>395 - Williston Basin</i>	<i>2,874</i>	<i>3,686</i>	<i>25,020</i>	<i>16,151</i>	<i>20,130</i>	<i>26,011</i>	<i>NA</i>
<i>430 - Permian Basin</i>	<i>11,816</i>	<i>8,104</i>	<i>17,596</i>	<i>8,913</i>	<i>12,974</i>	<i>22,597</i>	<i>NA</i>
<i>"Other" Basins</i>	<i>4,274</i>	<i>2,306</i>	<i>2,514</i>	<i>1,196</i>	<i>1,388</i>	<i>1,862</i>	<i>NA</i>
<i>Previous Estimate</i>	<i>20,357</i>	<i>14,881</i>	<i>48,826</i>	<i>27,839</i>	<i>37,662</i>	<i>53,438</i>	<i>NA</i>

NA (Not Applicable)

5 *Miscellaneous Production Flaring (Recalculation with Updated Data)*

6 Miscellaneous production flaring CH₄ emission estimates decreased by 28 percent in 2018 and decreased by an
 7 average of 4 percent for other years of the time series, compared to the previous Inventory. The 2018 decrease
 8 was primarily due to recalculations in the Permian and Gulf Coast basins, where GHGRP data showed lower CH₄
 9 flaring emissions, by 49 and 19 percent, respectively. These changes were due to GHGRP submission revisions.

10 **Table 3-53: Miscellaneous Production Flaring National CH₄ Emissions (Metric Tons CH₄)**

Source	1990	2005	2015	2016	2017	2018	2019
220 - Gulf Coast Basin (LA, TX)	0	428	4,028	1,979	2,160	1,918	2,449
395 - Williston Basin	0	182	2,183	854	1,618	3,022	3,462
430 - Permian Basin	0	803	3,085	2,794	4,981	4,280	11,023
Other Basins	0	1,311	2,814	1,463	1,996	2,005	2,605
Total Emissions	0	2,724	12,110	7,090	10,755	11,225	19,539
<i>220 - Gulf Coast Basin (LA, TX)</i>	<i>0</i>	<i>424</i>	<i>3,985</i>	<i>1,979</i>	<i>2,164</i>	<i>2,370</i>	<i>NA</i>
<i>395 - Williston Basin</i>	<i>0</i>	<i>191</i>	<i>2,293</i>	<i>888</i>	<i>1,603</i>	<i>2,947</i>	<i>NA</i>
<i>430 - Permian Basin</i>	<i>0</i>	<i>805</i>	<i>3,091</i>	<i>2,794</i>	<i>5,024</i>	<i>8,406</i>	<i>NA</i>
<i>Other Basins</i>	<i>0</i>	<i>1,440</i>	<i>3,074</i>	<i>1,452</i>	<i>2,018</i>	<i>1,812</i>	<i>NA</i>
<i>Previous Total Estimate</i>	<i>0</i>	<i>2,859</i>	<i>12,443</i>	<i>7,113</i>	<i>10,810</i>	<i>15,536</i>	<i>NA</i>

NA (Not Applicable)

11 Miscellaneous production flaring CO₂ emission estimates decreased by 2 percent in 2018 and decreased by less
 12 than 1 percent for other years of the time series, compared to the previous Inventory. The 2018 decrease was
 13 primarily due to recalculations of CO₂ from flaring in the Gulf Coast Basin, where GHGRP data showed lower CO₂
 14 emissions from flaring, by 17 percent. These changes were due to GHGRP submission revisions.

15 **Table 3-54: Miscellaneous Production Flaring National CO₂ Emissions (kt CO₂)**

Source	1990	2005	2015	2016	2017	2018	2019
220 - Gulf Coast Basin (LA, TX)	0	107	1,005	497	522	567	600
395 - Williston Basin	0	73	873	303	537	1,693	2,602
430 - Permian Basin	0	214	823	794	1,411	1,197	2,882

Other Basins	0	406	872	596	578	679	971
Total Emissions	0	800	3,574	2,190	3,048	4,136	7,055
<i>220 - Gulf Coast Basin (LA, TX)</i>	<i>0</i>	<i>106</i>	<i>997</i>	<i>497</i>	<i>526</i>	<i>687</i>	<i>NA</i>
<i>395 - Williston Basin</i>	<i>0</i>	<i>73</i>	<i>882</i>	<i>315</i>	<i>531</i>	<i>1,653</i>	<i>NA</i>
<i>430 - Permian Basin</i>	<i>0</i>	<i>215</i>	<i>825</i>	<i>794</i>	<i>1,424</i>	<i>1,183</i>	<i>NA</i>
<i>Other Basins</i>	<i>0</i>	<i>407</i>	<i>870</i>	<i>592</i>	<i>585</i>	<i>703</i>	<i>NA</i>
<i>Previous Total Estimate</i>	<i>0</i>	<i>801</i>	<i>3,573</i>	<i>2,198</i>	<i>3,066</i>	<i>4,226</i>	<i>NA</i>

NA (Not Applicable)

1 Transportation

2 Recalculations for the transportation segment have resulted in an average increase in calculated CH₄ and CO₂
3 emissions over the time series from this segment of less than 0.02 percent, compared to the previous Inventory.

4 Refining

5 Recalculations due to resubmitted GHGRP data in the refining segment have resulted in an average increase in
6 calculated CH₄ emissions over the time series from this segment of 0.1 percent and an average increase in
7 calculated CO₂ emissions over the time series of less than 0.01 percent, compared to the previous Inventory.

8 Planned Improvements

9 Mud Degassing

10 As part of the stakeholder process for the current (1990 to 2019) Inventory, EPA developed draft CH₄ emission
11 estimates for mud degassing in the exploration segment. To date, the Inventory has not included emissions from
12 exploration mud degassing. EPA's considerations for this source are documented in the EPA memorandum
13 *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2019: Update Under Consideration for Mud Degassing*
14 *Emissions (Mud Degassing Memo)*.⁸⁴ EPA estimated emissions using CH₄ emission factors from EPA (EPA 1977) and
15 the count of wells drilled from Enverus DrillingInfo data. To calculate emissions per well drilled, EPA incorporated
16 an estimate of 26 days as an average drilling duration and 61.2 percent (by weight) as the default CH₄ content of
17 associated gas. EPA developed national estimates for two different scenarios: 1) EPA assumed 80 percent of
18 drilling operations were performed using water-based muds and the remaining 20 percent used oil-based muds;
19 and 2) EPA assumed 100 percent of drilling operations were performed using water-based muds. Mud degassing
20 CH₄ emissions averaged 100 kt over the time series for scenario 1 and 118 kt for scenario 2, or around 3 MMT CO₂
21 Eq. This update would increase emissions from the exploration segment but would have a small impact on overall
22 CH₄ emissions from petroleum systems.

23 EPA notes that estimates for mud degassing using similar assumptions are included in several other bottom-up
24 inventories for greenhouse gases and other gases, including New York state, and the NEI. In response to
25 stakeholder feedback on the *Mud Degassing* memo, EPA continues to seek feedback on alternate assumptions for
26 borehole diameter and porosity, average total drilling days and drilling days in the producing formation, CH₄
27 content of the gas, and the effect of balanced and over-balanced mud degassing systems. EPA will further assess
28 the average drilling duration in an updated Enverus DrillingInfo dataset. Additionally, EPA is considering developing
29 CO₂ estimates for onshore production mud degassing using the CH₄ estimates and a ratio of CO₂-to-CH₄.

⁸⁴ Stakeholder materials including draft memoranda for the current (i.e., 1990 to 2019) Inventory are available at
<<https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems>>.

1 **Table 3-55: Draft Mud Degassing National CH₄ Emissions—Not Included in Totals (Metric**
 2 **Tons CH₄)**

Source	1990	2005	2015	2016	2017	2018	2019
Scenario 1 (80/20)	105,862	98,024	93,555	56,256	101,179	101,179	101,179
Scenario 2 (100)	124,543	115,322	110,065	66,183	119,035	119,035	119,035
Previous Estimate	NA	NA	NA	NA	NA	NA	NA

NA (Not Applicable)

Scenario 1 (80/20) = 80% water-based mud usage and 20% oil-based mud usage

Scenario 2 (100) = 100% water-based mud usage

3 CO₂ Uncertainty

4 As part of the stakeholder process for the current (1990 to 2019) Inventory, EPA developed a draft update to the
 5 uncertainty analysis for CO₂. The updated under consideration is documented in the memoranda, *Inventory of U.S.*
 6 *Greenhouse Gas Emissions and Sinks 1990-2019: Update Under Consideration for Natural Gas and Petroleum*
 7 *Systems CO₂ Uncertainty Estimates*.⁸⁵ EPA continues to seek stakeholder feedback on this update.

8 Upcoming Data, and Additional Data that Could Inform the Inventory

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

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

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

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

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

24 **Box 3-6: Carbon Dioxide Transport, Injection, and Geological Storage - TO BE UPDATED FOR FINAL REPORT**

Carbon dioxide is produced, captured, transported, and used for Enhanced Oil Recovery (EOR) as well as commercial and non-EOR industrial applications. This CO₂ is produced from both naturally-occurring CO₂ reservoirs and from industrial sources such as natural gas processing plants and ammonia plants. In the Inventory, emissions from naturally-produced CO₂ are estimated based on the specific application.

In the Inventory, CO₂ 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 CO₂, as noted in the *2006 IPCC Guidelines*, “At the Tier 1 or 2 methodology levels [EOR CO₂ is] indistinguishable from fugitive greenhouse gas emissions by the associated oil and gas activities.” In the U.S.

⁸⁵ <https://www.epa.gov/sites/production/files/2020-11/documents/ghgi-webinar-nov2020-co2.pdf>

estimates for oil and gas fugitive emissions, the Tier 2 emission factors for CO₂ include CO₂ 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 CO₂ from EOR and CO₂ occurring in the produced natural gas. Therefore, EOR CO₂ emitted through those pathways is included in CO₂ estimates in 1B2.

IPCC includes methodological guidance to estimate emissions from the capture, transport, injection, and geological storage of CO₂. 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 CO₂ 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 CO₂ emission estimates for geologic storage.

In the United States, facilities that produce CO₂ for various end-use applications (including capture facilities such as acid gas removal plants and ammonia plants), importers of CO₂, exporters of CO₂, facilities that conduct geologic sequestration of CO₂, and facilities that inject CO₂ underground, are required to report greenhouse gas data annually to EPA through its GHGRP. Facilities conducting geologic sequestration of CO₂ are required to develop and implement an EPA-approved site-specific monitoring, reporting and verification plan, and to report the amount of CO₂ sequestered using a mass balance approach.

GHGRP data relevant for this inventory estimate consists of national-level annual quantities of CO₂ 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 CO₂ sequestered in subsurface geological formations and 9,818 metric tons of CO₂ emitted from equipment leaks. In 2017, three facilities reported 9.1 MMT of CO₂ sequestered in subsurface geological formations, and 9,577 metric tons of CO₂ emitted from equipment leaks. In 2018, five facilities reported 16.7 MMT of CO₂ sequestered in subsurface geological formations and 11,023 metric tons of CO₂ emitted from equipment leaks.

The amount of CO₂ captured and extracted from natural and industrial sites for EOR applications in 2018 is 59.3 MMT CO₂ Eq. (59,318 kt) (see Table 3-56 and Table 3-57). The quantity of CO₂ captured and extracted is noted here for information purposes only; CO₂ captured and extracted from industrial and commercial processes is assumed to be emitted and included in emissions totals from those processes.

Table 3-56: Quantity of CO₂ Captured and Extracted for EOR Operations (MMT CO₂)

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 3-57: Quantity of CO₂ 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 (CH₄, CO₂, and N₂O) from natural gas systems in 2019 were 193.3 MMT CO₂ Eq., a decrease of 12 percent from 1990, primarily due to decreases in CH₄ emissions, and increased 5 percent from 2018, primarily due to increases in CH₄ emissions. From 2009, emissions increased by 5 percent, primarily due to increases in CO₂ emissions. National total dry gas production in the United States increased by 91 percent from 1990 to 2019, by 10 percent from 2018 to 2019, and by 65 percent from 2009 to 2019. Of the overall greenhouse gas emissions (193.3 MMT CO₂ Eq.), 81 percent are CH₄ emissions (156.4 MMT CO₂ Eq.), 19 percent are CO₂ emissions (36.8 MMT), and less than 0.01 percent are N₂O emissions (0.01 MMT CO₂ Eq.).

Overall, natural gas systems emitted 156.4 MMT CO₂ Eq. (6,258 kt CH₄) of CH₄ in 2019, a 17 percent decrease compared to 1990 emissions, and 4 percent increase compared to 2018 emissions (see Table 3-59 and Table 3-60). For non-combustion CO₂, a total of 36.9 MMT CO₂ Eq. (36,854 kt) was emitted in 2019, a 15 percent increase compared to 1990 emissions, and a 9 percent increase compared to 2018 levels. The 2019 N₂O emissions were estimated to be 0.01 MMT CO₂ Eq. (0.04 kt N₂O), a 120 percent increase compared to 1990 emissions, and a 2 percent increase compared to 2018 levels.

The 1990 to 2019 trend is not consistent across segments or gases. Overall, the 1990 to 2019 decrease in CH₄ emissions is due primarily to the decrease in emissions from the following segments: distribution (69 percent decrease), transmission and storage (35 percent decrease), processing (42 percent decrease), and exploration (87 percent decrease). Over the same time period, the production segment saw increased CH₄ emissions of 55 percent (with onshore production emissions increasing 38 percent, offshore production emissions decreasing 82 percent, and gathering and boosting [G&B] emissions increasing 120 percent). The 1990 to 2019 increase in CO₂ emissions is primarily due to an increase in CO₂ emissions in the production segment, where emissions from flaring have increased over time.

Methane and CO₂ 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 N₂O from flaring activities are included in the Inventory, with most of the emissions occurring in the processing and production segments. Note, CO₂ emissions exclude all combustion emissions (e.g., engine combustion) except for flaring CO₂ emissions. All combustion CO₂ emissions (except for flaring) are accounted for in Section 3.1 – CO₂ 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 2018) to ensure that the trend is accurate. Recalculations in natural gas systems in this year's Inventory include:

- Updated methodology for produced water (to expand included basins)
- Updated methodology for customer meters to use data from GTI 2009 and GTI 2019
- Recalculations due to GHGRP submission revisions

The Recalculations Discussion section below provides more details on the updated methods. In addition, several other updates are planned or under consideration for this year's Inventory, including an update to use the most recent Enverus DrillingInfo data (the well count data used here has not been updated from the previous Inventory due to time constraints) and an update under consideration on mud degassing.

1 Below is a characterization of the five major segments of the natural gas system: exploration, production (including
2 gathering and boosting), processing, transmission and storage, and distribution. Each of the segments is described
3 and the different factors affecting CH₄, CO₂, and N₂O emissions are discussed.

4 *Exploration.* Exploration includes well drilling, testing, and completions. Emissions from exploration accounted for
5 less than 1 percent of CH₄ emissions and of CO₂ emissions from natural gas systems in 2019. Well completions
6 accounted for approximately 95 percent of CH₄ emissions from the exploration segment in 2019, with the rest
7 resulting from well testing and drilling. Flaring emissions account for most of the CO₂ emissions. Methane
8 emissions from exploration decreased by 87 percent from 1990 to 2019, with the largest decreases coming from
9 hydraulically fractured gas well completions without reduced emissions completions (RECs). Methane emissions
10 decreased 36 percent from 2018 to 2019 due to decreases in emissions from hydraulically fractured well
11 completions with RECs and venting. Methane emissions were highest from 2005 to 2008. Carbon dioxide emissions
12 from exploration decreased by 42 percent from 1990 to 2019 and decreased 33 percent from 2018 to 2019 due to
13 decreases in flaring. Carbon dioxide emissions were highest from 2006 to 2008. Nitrous oxide emissions decreased
14 73 percent from 1990 to 2019 and decreased 94 percent from 2018 to 2019.

15 *Production (including gathering and boosting).* In the production segment, wells are used to withdraw raw gas
16 from underground formations. Emissions arise from the wells themselves, and from well-site equipment and
17 activities such as pneumatic controllers, tanks and separators, and liquids unloading. Gathering and boosting
18 emission sources are included within the production sector. The gathering and boosting sources include gathering
19 and boosting stations (with multiple emission sources on site) and gathering pipelines. The gathering and boosting
20 stations receive natural gas from production sites and transfer it, via gathering pipelines, to transmission pipelines
21 or processing facilities (custody transfer points are typically used to segregate sources between each segment).
22 Boosting processes include compression, dehydration, and transport of gas to a processing facility or pipeline.
23 Emissions from production (including gathering and boosting) accounted for 59 percent of CH₄ emissions and 29
24 percent of CO₂ emissions from natural gas systems in 2019. Emissions from gathering and boosting and pneumatic
25 controllers in onshore production accounted for most of the production segment CH₄ emissions in 2019. Within
26 gathering and boosting, the largest sources of CH₄ are compressor exhaust slip, compressor venting and leaks, and
27 tanks. Flaring emissions account for most of the CO₂ emissions from production, with the highest emissions coming
28 from flare stacks at gathering stations, miscellaneous onshore production flaring, and tank flaring. Methane
29 emissions from production increased by 55 percent from 1990 to 2019, due primarily to increases in emissions
30 from pneumatic controllers (due to an increase in the number of controllers, particularly in the number of
31 intermittent bleed controllers) and increases in emissions from compressor exhaust slip in gathering and boosting.
32 Methane emissions increased 4 percent from 2018 to 2019 due to increases in the number of high intermittent
33 bleed controllers and increase in emissions from tanks in gathering and boosting. Carbon dioxide emissions from
34 production increased by approximately a factor of 3.5 from 1990 to 2019 due to increases in emissions at flare
35 stacks in gathering and boosting and miscellaneous onshore production flaring, and increased 8 percent from 2018
36 to 2019 due primarily to increases in emissions from flare stacks and acid gas removal in gathering and boosting.
37 Nitrous oxide emissions increased 25 percent from 1990 to 2019 and increased 6 percent from 2018 to 2019. The
38 increase in N₂O emissions from 1990 to 2019 and from 2018 to 2019 is primarily due to increase in emissions from
39 flare stacks at gathering and boosting stations.

40 *Processing.* In the processing segment, natural gas liquids and various other constituents from the raw gas are
41 removed, resulting in “pipeline quality” gas, which is injected into the transmission system. Methane emissions
42 from compressors, including compressor seals, are the primary emission source from this stage. Most of the CO₂
43 emissions come from acid gas removal (AGR) units, which are designed to remove CO₂ from natural gas. Processing
44 plants accounted for 8 percent of CH₄ emissions and 67 percent of CO₂ emissions from natural gas systems.
45 Methane emissions from processing decreased by 42 percent from 1990 to 2019 as emissions from compressors
46 (leaks and venting) and equipment leaks decreased; and increased 3 percent from 2018 to 2019 due to increased
47 emissions from gas engines. Carbon dioxide emissions from processing decreased by 13 percent from 1990 to
48 2019, due to a decrease in AGR emissions, and increased 7 percent from 2018 to 2019 due to increased emissions
49 from flaring. Nitrous oxide emissions increased 39 percent from 2018 to 2019.

1 *Transmission and Storage.* Natural gas transmission involves high pressure, large diameter pipelines that transport
 2 gas long distances from field production and processing areas to distribution systems or large volume customers
 3 such as power plants or chemical plants. Compressor station facilities are used to move the gas throughout the
 4 U.S. transmission system. Leak CH₄ emissions from these compressor stations and venting from pneumatic
 5 controllers account for most of the emissions from this stage. Uncombusted compressor engine exhaust and
 6 pipeline venting are also sources of CH₄ emissions from transmission. Natural gas is also injected and stored in
 7 underground formations, or liquefied and stored in above ground tanks, during periods of low demand (e.g.,
 8 summer), and withdrawn, processed, and distributed during periods of high demand (e.g., winter). Leak and
 9 venting emissions from compressors are the primary contributors to CH₄ emissions from storage. Emissions from
 10 liquefied natural gas (LNG) stations and terminals are also calculated under the transmission and storage segment.
 11 Methane emissions from the transmission and storage segment accounted for approximately 23 percent of
 12 emissions from natural gas systems, while CO₂ emissions from transmission and storage accounted for 3 percent of
 13 the CO₂ emissions from natural gas systems. CH₄ emissions from this source decreased by 35 percent from 1990 to
 14 2019 due to reduced compressor station emissions (including emissions from compressors and leaks) and
 15 increased 6 percent from 2018 to 2019 due to increased emissions from transmission compressors. CO₂ emissions
 16 from transmission and storage were 6.9 times higher in 2019 than in 1990, due to increased emissions from LNG
 17 export terminals, and increased by 128 percent from 2018 to 2019, also due to LNG export terminals. The quantity
 18 of LNG exported from the U.S. increased by a factor of 21 from 1990 to 2019, and by 68 percent from 2018 to
 19 2019. LNG emissions are about 1 percent of CH₄ and 80 percent of CO₂ emissions from transmission and storage in
 20 year 2019. Nitrous oxide emissions from transmission and storage increased by 145 percent from 1990 to 2019
 21 and increased 169 percent from 2018 to 2019.

22 *Distribution.* Distribution pipelines take the high-pressure gas from the transmission system at “city gate” stations,
 23 reduce the pressure and distribute the gas through primarily underground mains and service lines to individual end
 24 users. There were 1,316,689 miles of distribution mains in 2019, an increase of 372,532 miles since 1990 (PHMSA
 25 2020). Distribution system emissions, which accounted for 9 percent of CH₄ emissions from natural gas systems
 26 and less than 1 percent of CO₂ emissions, result mainly from leak emissions from pipelines and stations. An
 27 increased use of plastic piping, which has lower emissions than other pipe materials, has reduced both CH₄ and
 28 CO₂ emissions from this stage, as have station upgrades at metering and regulating (M&R) stations. Distribution
 29 system CH₄ emissions in 2019 were 62 percent lower than 1990 levels and 1 percent lower than 2018 emissions.
 30 Distribution system CO₂ emissions in 2019 were 69 percent lower than 1990 levels and 1 percent lower than 2018
 31 emissions. Annual CO₂ emissions from this segment are less than 0.1 MMT CO₂ Eq. across the time series.

32 Total greenhouse gas emissions from the five major segments of natural gas systems are shown in MMT CO₂ Eq. in
 33 Table 3-58. Total CH₄ emissions for these same segments of natural gas systems are shown in MMT CO₂ Eq. (Table
 34 3-59) and kt (Table 3-60). Most emission estimates are calculated using a net emission approach. However, a few
 35 sources are still calculated with a potential emission approach. Reductions data are applied to those sources that
 36 use a potential emissions approach. In recent years 6.1 MMT CO₂ Eq. CH₄ are subtracted from production segment
 37 emissions and 6.7 MMT CO₂ Eq. CH₄ are subtracted from the transmission and storage segment to calculate net
 38 emissions. More disaggregated information on potential emissions, net emissions, and reductions data are
 39 available in Annex 3.6, Methodology for Estimating CH₄ and CO₂ Emissions from Natural Gas Systems.

40 **Table 3-58: Total Greenhouse Gas Emissions (CH₄, CO₂, and N₂O) from Natural Gas Systems**
 41 **(MMT CO₂ Eq.)**

Stage	1990	2005	2015	2016	2017	2018	2019
Exploration	4.4	11.9	1.3	0.9	1.7	1.2	0.8
Production	62.7	84.7	95.8	93.5	95.5	98.9	103.1
Processing	49.7	30.4	32.0	33.2	34.5	35.2	37.2
Transmission and Storage	57.4	36.2	34.4	34.8	32.9	35.3	38.2

Distribution	45.5	25.6	14.4	14.3	14.2	14.1	14.0
Total	219.7	188.9	177.8	176.8	178.8	184.7	193.3

Note: Totals may not sum due to independent rounding.

1 **Table 3-59: CH₄ Emissions from Natural Gas Systems (MMT CO₂ Eq.)^a**

Stage	1990	2005	2015	2016	2017	2018	2019
Exploration^b	4.0	10.3	1.0	0.7	1.2	0.8	0.5
Production	59.6	80.2	88.1	86.0	88.3	89.1	92.5
Onshore Production	36.9	54.4	50.9	48.9	49.6	50.0	57.1
Gathering and Boosting ^c	4.3	1.8	0.6	0.8	0.7	0.8	0.8
Offshore Production	18.5	23.9	36.6	36.3	38.0	38.3	40.7
Processing	21.3	11.6	11.0	11.2	11.5	12.1	12.4
Transmission and Storage	57.2	36.1	34.1	34.5	32.4	34.8	37.0
Distribution	45.5	25.6	14.3	14.3	14.2	14.1	14.0
Total	187.7	163.7	148.6	146.7	147.6	150.8	156.4

Note: Totals may not sum due to independent rounding.

^a These values represent CH₄ emitted to the atmosphere. CH₄ 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.

2 **Table 3-60: CH₄ Emissions from Natural Gas Systems (kt)^a**

Stage	1990	2005	2015	2016	2017	2018	2019
Exploration^b	162	411	41	27	48	34	22
Production	2,386	3,208	3,524	3,441	3,530	3,562	3,700
Onshore Production	1,478	2,177	2,036	1,955	1,983	2,001	2,285
Gathering and Boosting ^c	170	73	24	32	26	31	31
Offshore Production	738	958	1,464	1,453	1,521	1,531	1,627
Processing	853	463	440	448	460	483	497
Transmission and Storage	2,288	1,443	1,366	1,379	1,298	1,390	1,478
Distribution	1,819	1,023	574	573	569	565	560
Total	7,508	6,547	5,944	5,868	5,905	6,034	6,258

Note: Totals may not sum due to independent rounding.

^a These values represent CH₄ emitted to the atmosphere. CH₄ 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.

3 **Table 3-61: Non-combustion CO₂ Emissions from Natural Gas Systems (MMT)**

Stage	1990	2005	2015	2016	2017	2018	2019
Exploration	0.4	1.6	0.3	0.2	0.4	0.4	0.2
Production	3.0	4.5	7.7	7.5	7.3	9.8	10.6
Processing	28.3	18.8	21.0	22.0	23.0	23.1	24.8
Transmission and Storage	0.2	0.2	0.2	0.3	0.5	0.5	1.2
Distribution	0.1	+	+	+	+	+	+
Total	32.0	25.2	29.2	30.1	31.2	33.9	36.8

Note: Totals may not sum due to independent rounding.

+ Does not exceed 0.05 MMT CO₂ Eq.

1 **Table 3-62: Non-combustion CO₂ Emissions from Natural Gas Systems (kt)**

Stage	1990	2005	2015	2016	2017	2018	2019
Exploration	408	1,648	281	192	444	350	236
Production	3,046	4,491	7,656	7,496	7,268	9,825	10,571
Processing	28,338	18,836	20,977	22,022	22,980	23,126	24,786
Transmission and Storage	181	176	228	339	498	546	1,244
Distribution	50	26	13	13	12	12	12
Total	32,022	25,178	29,155	30,063	31,202	33,860	36,849

Note: Totals may not sum due to independent rounding.

2 **Table 3-63: N₂O Emissions from Natural Gas Systems (Metric Tons CO₂ Eq.)**

Stage	1990	2005	2015	2016	2017	2018	2019
Exploration	460	1,340	3,203	115	243	2,076	123
Production	4,346	5,823	9,884	8,902	4,459	5,090	5,414
Processing	NO	3,348	5,766	3,819	3,066	3,587	4,987
Transmission and Storage	257	309	346	382	462	234	630
Distribution	NO	NO	NO	NO	NO	NO	NO
Total	5,062	10,819	19,200	13,219	8,231	10,987	11,153

Note: Totals may not sum due to independent rounding.

NO (Not Occurring)

3 **Table 3-64: N₂O Emissions from Natural Gas Systems (Metric Tons N₂O)**

Stage	1990	2005	2015	2016	2017	2018	2019
Exploration	1.5	4.5	10.7	0.4	0.8	7.0	0.4
Production	14.6	19.5	33.2	29.9	15.0	17.1	18.2
Processing	NO	11.2	19.3	12.8	10.3	12.0	16.7
Transmission and Storage	0.9	1.0	1.2	1.3	1.6	0.8	2.1
Distribution	NO						
Total	17.0	36.3	64.4	44.4	27.6	36.9	37.4

Note: Totals may not sum due to independent rounding.

NO (Not Occurring)

4 Methodology

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

8 This section provides a general overview of the methodology for natural gas system emission estimates in the
9 Inventory, which involves the calculation of CH₄, CO₂, and N₂O emissions for over 100 emissions sources (i.e.,
10 equipment types or processes), and then the summation of emissions for each natural gas segment.

11 The approach for calculating emissions for natural gas systems generally involves the application of emission
12 factors to activity data. For most sources, the approach uses technology-specific emission factors or emission
13 factors that vary over time and take into account changes to technologies and practices, which are used to
14 calculate net emissions directly. For others, the approach uses what are considered “potential methane factors”
15 and emission reduction data to calculate net emissions. The estimates are developed with a Tier 2 approach. Tier 1
16 approaches are not used.

17 *Emission Factors.* Key references for emission factors for CH₄ and CO₂ emissions from the U.S. natural gas industry
18 include a 1996 study published by the Gas Research Institute (GRI) and EPA (GRI/EPA 1996), the EPA's GHGRP (EPA
19 2020), and others.

1 The 1996 GRI/EPA study developed over 80 CH₄ emission factors to characterize emissions from the various
2 components within the operating segments of the U.S. natural gas system. The GRI/EPA study was based on a
3 combination of process engineering studies, collection of activity data, and measurements at representative
4 natural gas facilities conducted in the early 1990s. Year-specific natural gas CH₄ compositions are calculated using
5 U.S. Department of Energy’s Energy Information Administration (EIA) annual gross production data for National
6 Energy Modeling System (NEMS) oil and gas supply module regions in conjunction with data from the Gas
7 Technology Institute (GTI, formerly GRI) Unconventional Natural Gas and Gas Composition Databases (GTI 2001).
8 These year-specific CH₄ compositions are applied to emission factors, which therefore may vary from year to year
9 due to slight changes in the CH₄ composition of natural gas for each NEMS region.

10 GHGRP Subpart W data were used to develop CH₄, CO₂, and N₂O emission factors for many sources in the
11 Inventory. In the exploration and production segments, GHGRP data were used to develop emission factors used
12 for all years of the time series for well testing, gas well completions and workovers with and without hydraulic
13 fracturing, pneumatic controllers and chemical injection pumps, condensate tanks, liquids unloading,
14 miscellaneous flaring, gathering and boosting pipelines, and certain sources at gathering and boosting stations. In
15 the processing segment, for recent years of the times series, GHGRP data were used to develop emission factors
16 for leaks, compressors, flares, dehydrators, and blowdowns/venting. In the transmission and storage segment,
17 GHGRP data were used to develop factors for all years of the time series for LNG stations and terminals and
18 transmission pipeline blowdowns, and for pneumatic controllers for recent years of the times series.

19 Other data sources used for CH₄ emission factors include Zimmerle et al. (2015) for transmission and storage
20 station leaks and compressors, GSI (2019) for underground storage well leaks, GTI (2009 and 2019) for commercial
21 and industrial meters, Lamb et al. (2015) for recent years for distribution pipelines and meter/regulator stations,
22 Zimmerle et al. (2019) for gathering and boosting stations, and Bureau of Ocean Energy Management (BOEM)
23 reports.

24 For CO₂ emissions from sources in the exploration, production and processing segments that use emission factors
25 not directly calculated from GHGRP data, data from the 1996 GRI/EPA study and a 2001 GTI publication were used
26 to adapt the CH₄ emission factors into related CO₂ emission factors. For sources in the transmission and storage
27 segment that use emission factors not directly calculated from GHGRP data, and for sources in the distribution
28 segment, data from the 1996 GRI/EPA study and a 1993 GTI publication were used to adapt the CH₄ emission
29 factors into non-combustion related CO₂ emission factors.

30 Flaring N₂O emissions were estimated for flaring sources using GHGRP data.

31 See Annex 3.6 for more detailed information on the methodology and data used to calculate CH₄, CO₂, and N₂O
32 emissions from natural gas systems.

33 *Activity Data.* Activity data were taken from various published data sets, as detailed in Annex 3.6. Key activity data
34 sources include data sets developed and maintained by EPA’s GHGRP; Enverus DrillingInfo, Inc. (Enverus
35 DrillingInfo 2019); BOEM; Federal Energy Regulatory Commission (FERC); EIA; the Natural Gas STAR Program
36 annual data; Oil and Gas Journal; and PHMSA.

37 For a few sources, recent direct activity data are not available. For these sources, either 2018 data were used as a
38 proxy for 2019 data, or a set of industry activity data drivers was developed and used to calculate activity data over
39 the time series. Drivers include statistics on gas production, number of wells, system throughput, miles of various
40 kinds of pipe, and other statistics that characterize the changes in the U.S. natural gas system infrastructure and
41 operations. More information on activity data and drivers is available in Annex 3.6.

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

43 *Calculating Net Emissions.* For most sources, net emissions are calculated directly by applying emission factors to
44 activity data. Emission factors used in net emission approaches reflect technology-specific information, and take
45 into account regulatory and voluntary reductions. However, for production and transmission and storage, some
46 sources are calculated using potential emission factors, and the step of deducting CH₄ that is not emitted from the
47 total CH₄ potential estimates to develop net CH₄ emissions is applied. To take into account use of such
48 technologies and practices that result in lower emissions but are not reflected in “potential” emission factors, data

1 are collected on both regulatory and voluntary reductions. Regulatory actions addressed using this method include
 2 EPA National Emission Standards for Hazardous Air Pollutants (NESHAP) regulations for dehydrator vents.
 3 Voluntary reductions included in the Inventory are those reported to Natural Gas STAR for certain sources.

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

7 The United States reports data to the UNFCCC using this Inventory report along with Common Reporting Format
 8 (CRF) tables. This note is provided for those reviewing the CRF tables: The notation key “IE” is used for CO₂ and CH₄
 9 emissions from venting and flaring in CRF table 1.B.2. Disaggregating flaring and venting estimates across the
 10 Inventory would involve the application of assumptions and could result in inconsistent reporting and, potentially,
 11 decreased transparency. Data availability varies across segments within oil and gas activities systems, and emission
 12 factor data available for activities that include flaring can include emissions from multiple sources (flaring, venting
 13 and leaks).

14 **Uncertainty and Time-Series Consistency-TO BE UPDATED FOR** 15 **FINAL INVENTORY REPORT**

16 EPA has conducted a quantitative uncertainty analysis using the IPCC Approach 2 methodology (Monte Carlo
 17 Simulation technique) to characterize the uncertainty for natural gas systems. For more information on the
 18 approach, please see the memorandum *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2016: Natural*
 19 *Gas and Petroleum Systems Uncertainty Estimates (2018 Uncertainty Memo)*.⁸⁶ EPA used Microsoft Excel's @RISK
 20 add-in tool to estimate the 95 percent confidence bound around CH₄ emissions from natural gas systems for the
 21 current Inventory, then applied the calculated bounds to both CH₄ and CO₂ emissions estimates. For the analysis,
 22 EPA focused on the 13 highest-emitting sources for the year 2018, which together emitted 83 percent of methane
 23 from natural gas systems in 2018, and extrapolated the estimated uncertainty for the remaining sources. The
 24 @RISK add-in provides for the specification of probability density functions (PDFs) for key variables within a
 25 computational structure that mirrors the calculation of the inventory estimate. The IPCC guidance notes that in
 26 using this method, "some uncertainties that are not addressed by statistical means may exist, including those
 27 arising from omissions or double counting, or other conceptual errors, or from incomplete understanding of the
 28 processes that may lead to inaccuracies in estimates developed from models." The uncertainty bounds reported
 29 below only reflect those uncertainties that EPA has been able to quantify and do not incorporate considerations
 30 such as modeling uncertainty, data representativeness, measurement errors, misreporting or misclassification. The
 31 understanding of the uncertainty of emission estimates for this category evolves and improves as the underlying
 32 methodologies and datasets improve.

33 The results presented below provide the 95 percent confidence bound within which actual emissions from this
 34 source category are likely to fall for the year 2018, using the IPCC methodology. The results of the Approach 2
 35 uncertainty analysis are summarized in Table 3-65. Natural gas systems CH₄ emissions in 2018 were estimated to
 36 be between 118.2 and 159.6 MMT CO₂ Eq. at a 95 percent confidence level. Natural gas systems CO₂ emissions in
 37 2018 were estimated to be between 29.5 and 39.9 MMT CO₂ Eq. at a 95 percent confidence level. Uncertainty
 38 bounds for other years of the time series have not been calculated, but uncertainty is expected to vary over the
 39 time series. For example, years where many emission sources are calculated with interpolated data would likely
 40 have higher uncertainty than years with predominantly year-specific data.

41 **Table 3-65: Approach 2 Quantitative Uncertainty Estimates for CH₄ and Non-combustion CO₂**
 42 **Emissions from Natural Gas Systems (MMT CO₂ Eq. and Percent)**

Source	Gas	2018 Emission Estimate	Uncertainty Range Relative to Emission Estimate ^a
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⁸⁶ See <<https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems>>.

		(MMT CO ₂ Eq.) ^b	(MMT CO ₂ Eq.)		(%)	
			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 CH₄ 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 3-59 and Table 3-60.

^c An uncertainty analysis for the CO₂ emissions was not performed. The relative uncertainty estimated (expressed as a percent) from the CH₄ uncertainty analysis was applied to the point estimate of CO₂ emissions.

1 GHGRP data available (starting in 2011) and other recent data sources have improved estimates of emissions from
2 natural gas systems. To develop a consistent time series, for sources with new data, EPA reviewed available
3 information on factors that may have resulted in changes over the time series (e.g., regulations, voluntary actions)
4 and requested stakeholder feedback on trends as well. For most sources, EPA developed annual data for 1993
5 through 2010 by interpolating activity data or emission factors or both between 1992 and 2011 data points.
6 Information on time-series consistency for sources updated in this year's Inventory can be found in the
7 Recalculations Discussion below, with additional detail provided in supporting memos (relevant memos are cited in
8 the Recalculations Discussion). For detailed documentation of methodologies, please see Annex 3.5.
9 Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990
10 through 2019. Details on the emission trends through time are described in more detail in the Methodology
11 section, above.

12 QA/QC and Verification Discussion

13 The natural gas systems emission estimates in the Inventory are continually being reviewed and assessed to
14 determine whether emission factors and activity factors accurately reflect current industry practices. A QA/QC
15 analysis was performed for data gathering and input, documentation, and calculation. QA/QC checks are
16 consistently conducted to minimize human error in the model calculations. EPA performs a thorough review of
17 information associated with new studies, GHGRP data, regulations, public webcasts, and the Natural Gas STAR
18 Program to assess whether the assumptions in the Inventory are consistent with current industry practices. The
19 EPA has a multi-step data verification process for GHGRP data, including automatic checks during data-entry,
20 statistical analyses on completed reports, and staff review of the reported data. Based on the results of the
21 verification process, the EPA follows up with facilities to resolve mistakes that may have occurred.⁸⁷

22 As in previous years, EPA conducted early engagement and communication with stakeholders on updates prior to
23 public review. EPA held stakeholder webinars in September and November of 2020. EPA released memos detailing
24 updates under consideration and requesting stakeholder feedback.

25 In recent years, several studies have measured emissions at the source level and at the national or regional level
26 and calculated emission estimates that may differ from the Inventory. There are a variety of potential uses of data
27 from new studies, including replacing a previous estimate or factor, verifying or QA of an existing estimate or
28 factor, and identifying areas for updates. In general, there are two major types of studies related to oil and gas
29 greenhouse gas data: studies that focus on measurement or quantification of emissions from specific activities,
30 processes and equipment, and studies that use tools such as inverse modeling to estimate the level of overall
31 emissions needed to account for measured atmospheric concentrations of greenhouse gases at various scales. The
32 first type of study can lead to direct improvements to or verification of Inventory estimates. In the past few years,
33 EPA has reviewed and in many cases, incorporated data from these data sources. The second type of study can
34 provide general indications of potential over- and under-estimates. A key challenge in using these types of studies
35 to assess Inventory results is having a relevant basis for comparison (i.e., the independent study should assess data

⁸⁷ See <https://www.epa.gov/sites/production/files/2015-07/documents/ghgrp_verification_factsheet.pdf>.

1 from the Inventory and not another data set, such as the Emissions Database for Global Atmospheric Research, or
 2 “EDGAR”). In an effort to improve the ability to compare the national-level inventory with measurement results
 3 that may be at other scales, a team at Harvard University along with EPA and other coauthors developed a gridded
 4 inventory of U.S. anthropogenic methane emissions with 0.1° x 0.1° spatial resolution, monthly temporal
 5 resolution, and detailed scale-dependent error characterization.⁸⁸ The gridded methane inventory is designed to
 6 be consistent with the 2016 *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2014* estimates for the
 7 year 2012, which presents national totals.⁸⁹

8 Recalculations Discussion

9 EPA received information and data related to the emission estimates through GHGRP reporting, the annual
 10 Inventory formal public notice periods, stakeholder feedback on updates under consideration, and new studies. In
 11 September and November 2020, EPA released draft memoranda that discussed changes under consideration, and
 12 requested stakeholder feedback on those changes. Memoranda cited in the Recalculations Discussion below are:
 13 *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2019: Update Under Consideration for Natural Gas*
 14 *Customer Meter Emissions (Customer Meters memo)* and *Inventory of U.S. Greenhouse Gas Emissions and Sinks*
 15 *1990-2019: Update Under Consideration for Produced Water Emissions (Produced Water memo)*.

16 EPA thoroughly evaluated relevant information available and made several updates to the Inventory, including
 17 using revised emission factors and produced water volumes to calculate produced water emissions, and using GTI
 18 2019 along with GTI 2009 study data to calculate customer meter emissions. In addition, certain sources did not
 19 undergo methodological updates, but CH₄ and/or CO₂ emissions changed by greater than 0.05 MMT CO₂ Eq.,
 20 comparing the previous estimate for 2018 to the current (recalculated) estimate for 2018. The emissions changes
 21 were mostly due to GHGRP data submission revisions.

22 The combined impact of revisions to 2018 natural gas sector CH₄ emissions, compared to the previous Inventory, is
 23 an increase from 140.0 to 150.8 MMT CO₂ Eq. (10.9 MMT CO₂ Eq., or 8 percent). The recalculations resulted in an
 24 average increase in CH₄ emission estimates across the 1990 through 2018 time series, compared to the previous
 25 Inventory, of 5.8 MMT CO₂ Eq., or 4 percent.

26 The combined impact of revisions to 2018 natural gas sector CO₂ emissions, compared to the previous Inventory, is
 27 a decrease from 35.0 MMT to 33.9 MMT, or 3 percent. The recalculations resulted in an average decrease in
 28 emission estimates across the 1990 through 2018 time series, compared to the previous Inventory, of 0.1 MMT
 29 CO₂ Eq., or 0.4 percent.

30 The combined impact of revisions to 2018 natural gas sector N₂O emissions, compared to the previous Inventory, is
 31 an increase from 10.4 kt CO₂ Eq. to 11.0 kt CO₂ Eq., or 6 percent. The recalculations resulted in an average increase
 32 in emission estimates across the 1990 through 2018 time series, compared to the previous Inventory, of 6 percent.

33 In Table 3-66 and Table 3-67 below are categories in Natural Gas Systems with recalculations resulting in a change
 34 of greater than 0.05 MMT CO₂ Eq., comparing the previous estimate for 2018 to the current (recalculated)
 35 estimate for 2018. No changes made to N₂O estimates resulted in a change greater than 0.05 MMT CO₂ Eq. For
 36 more information, please see the Recalculations Discussion below.

37 **Table 3-66: Recalculations of CO₂ in Natural Gas Systems (MMT CO₂)**

Stage and Emission Source	Previous Estimate Year 2018, 2020 Inventory	Current Estimate Year 2018, 2021 Inventory	Current Estimate Year 2019, 2021 Inventory
Exploration	0.4	0.4	0.2
HF Gas Well Completions	0.4	0.3	0.2

⁸⁸ See <<https://www.epa.gov/ghgemissions/gridded-2012-methane-emissions>>.

⁸⁹ See <<https://www.epa.gov/ghgemissions/us-greenhouse-gas-inventory-report-1990-2014>>.

Production	9.6	9.8	10.6
Gathering Stations Flares Stacks	4.2	4.4	5.0
Processing	24.5	23.1	24.8
AGR Vents	17.5	16.7	16.5
Flares	7.0	6.4	8.3
Transmission and Storage	0.5	0.5	1.2
LNG Export Terminals	0.3	0.3	1.0
Distribution	+	+	+
Customer Meters	+	+	+
Total	35.0	33.9	36.9

+ Does not exceed 0.05 MMT CO₂.

1 **Table 3-67: Recalculations of CH₄ in Natural Gas Systems (MMT CO₂ Eq.)**

Stage and Emission Source	Previous Estimate Year 2018, 2020 Inventory	Current Estimate Year 2018, 2021 Inventory	Current Estimate Year 2019, 2021 Inventory
Exploration	1.1	0.8	0.5
HF Gas Well Completions	1.0	0.8	0.5
Non-HF Gas Well Completions	0.1	+	+
Production	80.9	89.1	92.5
Produced Water (Onshore Production)	1.5	5.1	5.1
G&B Stations	31.4	34.9	37.1
Pneumatic Controllers (Onshore Production)	25.4	25.6	27.3
Liquids Unloading	4.4	4.9	4.3
HF Workovers	0.6	0.5	0.4
Processing	12.2	12.1	12.4
Reciprocating Compressors	1.6	1.5	1.2
Transmission and Storage	33.9	34.8	37.0
Reciprocating Compressors (Transmission)	9.2	9.3	10.2
Pneumatic Controllers (Storage)	+	0.6	0.6
Distribution	11.8	14.1	14.0
Customer Meters	1.4	3.7	3.7
Total	140.0	150.8	156.4

+ Does not exceed 0.05 MMT CO₂ Eq.

2 Exploration

3 HF Gas Well Completions (Recalculation with Updated Data)

- 4 HF gas well completions CH₄ emissions estimates decreased by an average of 1 percent across the time series.
5 Emissions decreased by 18 percent in 2018, compared to the previous Inventory, with the largest change being in
6 RECs with Venting. These changes were due to GHGRP submission revisions.

1 **Table 3-68: HF Gas Well Completions National Emissions (Metric Tons CH₄)**

Source	1990	2005	2015	2016	2017	2018	2019
HF Completions - Non-REC with Venting	151,775	382,269	924	1,109	2,932	1,085	641
HF Completions - Non-REC with Flaring	2,149	6,822	394	75	476	621	335
HF Completions - REC with Venting	0	6,483	14,463	12,569	37,650	28,934	17,827
HF Completions - REC with Flaring	0	1,853	8,760	4,581	5,656	1,344	1,139
Total Emissions	153,924	397,427	24,541	18,334	46,713	31,984	19,942
<i>Previous Estimate</i>	<i>153,924</i>	<i>397,427</i>	<i>24,566</i>	<i>18,177</i>	<i>47,414</i>	<i>39,036</i>	<i>NA</i>

NA (Not Applicable)

2 HF gas well completion CO₂ emissions estimates decreased by an average of approximately 2 percent across the
3 time series and decreased by 26 percent in 2018, compared to the previous Inventory, primarily due to decreases
4 in emissions from RECs with Flaring. These changes were due to GHGRP submission revisions.

5 **Table 3-69: HF Gas Well Completions National Emissions (kt CO₂)**

Source	1990	2005	2015	2016	2017	2018	2019
HF Completions - Non-REC with Venting	10	26	0.2	+	0.4	+	+
HF Completions - Non-REC with Flaring	389	1,235	49	12	37	54	32
HF Completions - REC with Venting	0	3	1	0	1	3	0
HF Completions - REC with Flaring	0	370	217	167	398	233	198
Total Emissions	399	1,633	267	179	436	290	230
<i>Previous Estimate</i>	<i>399</i>	<i>1,633</i>	<i>268</i>	<i>177</i>	<i>449</i>	<i>392</i>	<i>NA</i>

+ Does not exceed 0.5 kt CO₂

NA (Not Applicable)

6 **Non-HF Gas Well Completions (Recalculation with Updated Data)**

7 Non-HF gas well completion CH₄ emissions estimates decreased by an average of 3 percent across the time series
8 and decreased by 84 percent in 2018, compared to the previous inventory. These changes were due to GHGRP
9 submission revisions and a correction to the Inventory calculations of the number of non-HF completions that
10 were vented versus flared in 2018.

11 **Table 3-70: Non-HF Gas Well Completions National Emissions (Metric Tons CH₄)**

Source	1990	2005	2015	2016	2017	2018	2019
Non-HF Completions - Vented	5,717	10,250	13,631	8,001	783	248	769
Non-HF Completions - Flared	20	36	36	76	657	437	0.2
Total Emissions	5,736	10,286	13,667	8,077	1,440	685	769
<i>Previous Estimate</i>	<i>5,717</i>	<i>10,252</i>	<i>13,667</i>	<i>8,077</i>	<i>1,440</i>	<i>4,285</i>	<i>NA</i>

NA (Not Applicable)

12 Production

13 *Produced Water (Methodological Update)*

1 EPA developed a revised estimate for produced water from natural gas wells. Previous Inventories only estimated
 2 emissions for two CBM formations (i.e., Powder River in Wyoming and Black Warrior in Alabama. The revised
 3 estimate covers all gas formations. EPA’s considerations for this source are documented in the *Produced Water*
 4 *Memo*.⁹⁰ Produced water quantities (i.e., bbl) from natural gas wells were obtained for the 29 largest natural gas-
 5 producing states as described below:

- 6 • Produced water quantities were obtained from Enverus DrillingInfo data for 22 states (i.e., AK, AL, AR, AZ,
 7 CA, CO, FL, LA, MI, MO, MS, MT, ND, NE, NM, NV, NY, SD, TX, UT, VA, and WY) (Enverus DrillingInfo 2019)
- 8 • Produced water quantities were provided by 4 states – KS (Kansas Department of Health and Environment
 9 2020), OH (Ohio Environmental Protection Agency 2020), OK (Oklahoma Department of Environmental
 10 Quality 2020), and PA (Pennsylvania Department of Environmental Protection 2020)
- 11 • Produced water quantities were estimated for 3 states (IL, IN, and WV) using produced water production
 12 ratios estimated using 2011 Enverus DrillingInfo data combined with EIA state-level natural gas/CBM
 13 production quantities (IL and IN [1990-1999]) (EIA 2020), state-provided natural gas/CBM production
 14 quantities (IN [2000-2019]) (Indiana Department of Natural Resources 2020), and Enverus DrillingInfo
 15 data (WVEPA applied an emission factor from the Production Module of the 2017 Oil and Gas Tool.

16 While the previous estimate included only two CBM basins and the revision includes all CBM basins, the revision
 17 results in an overall decrease in the produced water CH₄ calculated for CBM wells of about 50 percent in recent
 18 years. Overall, the update increases the emission estimate for produced water (now including all gas production),
 19 which is around 3 times higher in recent years than in the previous Inventory.

20 EPA received comments on the *Produced Water Memo* and continues to seek feedback. These comments included
 21 a recommendation to use the same emission factors for produced water from natural gas wells and CBM wells,
 22 which is implemented here. EPA continues to seek feedback on the fraction of produced water that is routed to
 23 tanks and undergoes flashing, and the fraction of these tanks that have controls and how such controls should be
 24 taken into account.

25 **Table 3-71: Produced Water National CH₄ Emissions (Metric Tons CH₄)**

Source	1990	2005	2015	2016	2017	2018	2019
Natural Gas Wells	74,637	120,849	156,460	140,575	143,592	173,459	173,459
CBM Wells	10,271	64,131	37,083	33,004	31,658	30,011	30,011
Total	84,908	184,980	193,543	173,579	175,250	203,470	203,470
<i>Previous Estimate</i>							
<i>Black Warrior CBM</i>	<i>2,724</i>	<i>9,879</i>	<i>12,788</i>	<i>12,796</i>	<i>12,796</i>	<i>12,796</i>	<i>12,796</i>
<i>Powder River CBM</i>	<i>43</i>	<i>50,005</i>	<i>47,957</i>	<i>48,877</i>	<i>48,877</i>	<i>48,877</i>	<i>48,877</i>
Total	2,767	59,884	60,745	61,673	61,673	61,673	61,673

26 ***Gathering and Boosting (G&B) Stations (Recalculation with Updated Data)***

27 Methane emission estimates for sources at gathering and boosting stations increased in the current Inventory by
 28 an average of 2 percent across the time series, compared to the previous Inventory. The G&B sources with the
 29 largest increase in CH₄ emissions estimates for year 2018 are tanks (increase of 70 kt, or 39 percent), gas engines
 30 (increase of 19 kt, or 5 percent), and station blowdowns (increase of 17 kt or 27 percent). The 2018 CH₄ estimates
 31 in the current Inventory for gathering station sources increased by 10 percent, compared to the previous
 32 Inventory. These changes were due to GHGRP submission revisions.

33 Flare stack CO₂ emissions at G&B stations increased in the current inventory by an average 0.7 percent, compared
 34 to the previous Inventory. These changes were due to GHGRP submission revisions.

⁹⁰ See <<https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems>>.

1 **Table 3-72: Gathering Stations Sources National CH₄ Emissions (Metric Tons CH₄)**

Source	1990	2005	2015	2016	2017	2018	2019
Compressors	130,319	165,625	262,671	260,325	278,692	296,279	309,465
Tanks	130,726	166,142	263,492	261,139	255,244	251,243	301,338
Station Blowdowns	20,648	26,242	41,619	41,247	63,833	78,550	68,773
Dehydrator Vents - Large units	35,905	45,632	72,370	71,724	61,297	56,932	55,218
High-bleed Pneumatic Devices	17,409	22,126	35,091	34,777	33,985	24,599	23,624
Intermittent Bleed Pneumatic Devices	80,004	101,679	161,256	159,816	178,037	163,253	170,952
Low-Bleed Pneumatic Devices	2,775	3,527	5,594	5,544	5,877	5,803	6,819
Gas Engines	172,478	219,206	347,647	344,542	369,192	392,459	410,376
Other Gathering Sources	147,967	207,753	274,289	274,273	275,121	261,539	280,391
Total Emissions	738,231	957,932	1,464,029	1,453,387	1,521,278	1,530,657	1,626,956
<i>Previous Estimate</i>	728,959	946,086	1,445,417	1,435,084	1,442,951	1,390,566	NA

NA (Not Applicable)

2 **Table 3-73: Gathering Stations Flare Stacks National CO₂ Emissions (Metric Tons CO₂)**

Source	1990	2005	2015	2016	2017	2018	2019
Flare Stacks	1,362,734	1,731,928	2,746,736	2,722,202	2,317,495	4,386,761	5,005,631
<i>Previous Estimate</i>	1,354,751	1,721,783	2,730,646	2,706,255	2,300,171	4,205,760	NA

NA (Not Applicable)

3 *Pneumatic Controllers (Recalculation with Updated Data)*

4 Pneumatic controller CH₄ emission estimates increased in the current Inventory by an average of 0.2 percent
5 across the time series, compared to the previous Inventory. This change was due to GHGRP submission revisions
6 which increased the number of intermittent bleed controllers.

7 **Table 3-74: Production Segment Pneumatic Controller National Emissions (Metric Tons CH₄)**

Source	1990	2005	2015	2016	2017	2018	2019
Low Bleed	0	23,222	31,837	31,824	34,643	34,034	32,508
High Bleed	296,948	464,683	102,209	105,119	108,950	88,623	72,274
Intermittent Bleed	193,647	538,247	942,141	901,222	922,176	903,626	987,134
Total Emissions	490,594	1,026,151	1,076,187	1,038,165	1,065,770	1,026,283	1,091,915
<i>Previous Estimate</i>	490,594	1,023,770	1,072,732	1,037,136	1,062,086	1,016,357	NA

NO (Not Occurring)
NA (Not Applicable)

8 *Liquids Unloading (Recalculation with Updated Data)*

9 Liquids unloading CH₄ emission estimates increased for 2018 by 10 percent in the current Inventory, compared to
10 the previous Inventory. Compared to the previous Inventory, on average across the time series, liquids unloading
11 CH₄ emission estimates increased slightly more than 1 percent. These changes were due to GHGRP submission
12 revisions.

1 **Table 3-75: Liquids Unloading National Emissions (Metric Tons CH₄)**

Source	1990	2005	2015	2016	2017	2018	2019
Unloading with Plunger Lifts	NO	125,627	62,867	59,881	58,670	79,994	74,573
Unloading without Plunger Lifts	371,391	247,053	98,247	82,070	87,697	114,632	95,853
Total Emissions	371,391	372,680	161,114	141,951	146,367	194,626	170,426
<i>Previous Estimated Emissions</i>	<i>371,391</i>	<i>372,614</i>	<i>160,061</i>	<i>127,663</i>	<i>129,790</i>	<i>177,298</i>	<i>NA</i>

NO (Not Occurring)
NA (Not Applicable)

2 *HF Gas Well Workovers (Recalculation with Updated Data)*

3 HF gas well workover CH₄ emissions decreased an average of 1 percent across the 1990 to 2018 time series and
4 decreased by 16 percent in 2018, when comparing the current Inventory to the previous Inventory, mostly due to
5 decreases in emissions from RECs with Venting. These changes were due to GHGRP submission revisions.

6 **Table 3-76: HF Gas Well Workovers National Emissions (Metric Tons CH₄)**

Source	1990	2005	2015	2016	2017	2018	2019
HF Workovers - Non-REC with Venting	25,774	60,903	1,752	7,530	8,638	1,394	4,301
HF Workovers - Non-REC with Flaring	365	953	80	72	521	1,094	606
HF Workovers - REC with Venting	NO	576	8,685	6,384	16,146	18,010	8,824
HF Workovers - REC with Flaring	NO	4	1,695	1,234	4,885	39	257
Total Emissions	26,139	62,437	12,212	15,220	30,190	20,537	13,988
<i>Previous Estimate</i>	<i>26,139</i>	<i>62,437</i>	<i>12,175</i>	<i>15,155</i>	<i>31,485</i>	<i>24,422</i>	<i>NA</i>

NO (Not Occurring)
NA (Not Applicable)

7 **Processing**

8 *Acid Gas Removal (Recalculation with Updated Data)*

9 Acid gas removal unit (AGR) CO₂ emission estimates decreased by less than 1 percent across the time series,
10 compared to the previous Inventory. The 2018 estimate decreased by 4 percent when compared to the previous
11 inventory. These changes are due to GHGRP submission revisions.

12 **Table 3-77: AGR National CO₂ Emissions (kt CO₂)**

Source	1990	2005	2015	2016	2017	2018	2019
Acid Gas Removal	28,282	15,281	14,878	16,741	17,218	16,699	16,498
<i>Previous Estimate</i>	<i>28,282</i>	<i>15,339</i>	<i>14,979</i>	<i>16,679</i>	<i>17,182</i>	<i>17,451</i>	<i>NA</i>

NA (Not Applicable)

13 *Flares (Recalculation with Updated Data)*

14 Processing segment flare CO₂ emission estimates decreased by less than 1 percent across the 1993 to 2018 time
15 series in the current Inventory. Processing segment flare CO₂ emission estimates decreased by approximately 8
16 percent for 2018 in the current Inventory, compared to the previous Inventory. These changes are due to GHGRP
17 submission revisions.

18 **Table 3-78: Processing Segment Flares National Emissions (kt CO₂)**

Source	1990	2005	2015	2016	2017	2018	2019
Flares	NO	3,517	6,057	5,246	5,726	6,394	8,257
<i>Previous Estimate</i>	<i>NO</i>	<i>3,515</i>	<i>6,054</i>	<i>5,195</i>	<i>5,679</i>	<i>6,981</i>	<i>NA</i>

NO (Not Occurring)
 NA (Not Applicable)

1 *Reciprocating Compressors (Recalculation with Updated Data)*

2 Reciprocating compressor CH₄ emission estimates decreased by less than 1 percent on average for 2011 to 2018 in
 3 the current Inventory and decreased by 5 percent for 2018 in the current Inventory, compared to the previous
 4 Inventory. This decrease in the CH₄ emission estimates is due to GHGRP submission revisions.

5 **Table 3-79: Processing Segment Reciprocating Compressors National Emissions (Metric**
 6 **Tons CH₄)**

Source	1990	2005	2015	2016	2017	2018	2019
Reciprocating Compressors	324,939	NA	67,988	63,565	64,789	59,373	46,652
<i>Previous Estimate</i>	324,939	NA	67,982	63,682	64,955	62,574	NA

NA (Not Applicable)

7 **Transmission and Storage**

8 There were no methodological updates to the transmission and storage segment, but there were recalculations
 9 due to updated data that resulted in an average increase in calculated emissions over the time series from this
 10 segment of 0.19 MMT CO₂ Eq. of CH₄ (or 0.5 percent) and less than 0.01 MMT CO₂ (or 2 percent).

11 *Transmission Station Reciprocating Compressors (Recalculation with Updated Data)*

12 Methane emission estimates from reciprocating compressors at transmission compressor stations increased by an
 13 average of 0.2 percent for 2011 to 2018, compared to the previous Inventory. This increase in the CH₄ emission
 14 estimates is due to GHGRP submission revisions.

15 **Table 3-80: Transmission Station Reciprocating Compressors National Emissions (Metric**
 16 **Tons CH₄)**

Source	1990	2005	2015	2016	2017	2018	2019
Transmission Station – Reciprocating Compressors	NO	NO	341,316	345,224	347,830	373,233	406,453
<i>Previous Estimate</i>	NO	NO	341,316	345,224	346,527	369,976	NA

NO (Not Occurring)

NA (Not Applicable)

17 *Storage Pneumatic Controllers (Recalculation with Updated Data)*

18 Storage segment pneumatic controller CH₄ emission estimates increased in the current Inventory for 2014-2018,
 19 compared to the previous Inventory. Emission estimates for 2018 increased by 24,169 metric tons CH₄, compared
 20 to the previous Inventory. This increase in the CH₄ emission estimates is due to GHGRP submission revisions.

21

22 **Table 3-81: Storage Segment Pneumatic Controller National Emissions (Metric Tons CH₄)**

Source	1990	2005	2015	2016	2017	2018	2019
Low Bleed	NE	NE	15,902	19,904	20,465	17,291	17,187
High Bleed	NE	NE	5,734	5,648	6,419	6,485	6,365
Intermittent Bleed	NE	NE	401	413	480	535	516
Total Emissions	44,441	35,263	22,038	25,965	27,364	24,310	24,067

<i>Previous Estimate</i>	44,441	35,263	22,094	1,402	27,364	141	NA
NE (Not Estimated)							
NA (Not Applicable)							

1 **LNG Export Terminals (Recalculation with Updated Data)**

2 LNG export terminal CO₂ emissions estimates for equipment leaks, compressors, and flares increased by 20
3 percent in 2018, compared to the previous Inventory. This increase in the CO₂ emission estimate for 2018 is due to
4 GHGRP submission revisions.

5 **Table 3-82: LNG Export Terminal National Emissions (Metric Tons CO₂)**

Source	1990	2005	2015	2016	2017	2018	2019
LNG Export Terminals (eq. leaks, compressors, flares)	23	23	23	97,935	277,979	327,535	979,142
<i>Previous Estimate</i>	23	23	23	97,935	277,979	273,956	NA
NA (Not Applicable)							

6 **Distribution**

7 **Customer Meters (Methodological Update)**

8 EPA updated the commercial and industrial meters methodologies to use data leak data from a GTI 2009 and a GTI
9 2019 study. The GTI 2019 study measured CH₄ emissions rates at commercial and industrial meters in six regions
10 across the country and calculated population EFs for each meter type. The GTI 2009 study conducted similar
11 measurements and was used to calculate emissions for commercial and industrial meters in the previous (1990 to
12 2018) Inventory. EPA applied weighted average population EFs from the two studies across the time series for the
13 methodology implemented in the Inventory. The *Customer Meters memo* provides details on the methodology
14 implemented into the final inventory.

15 Commercial and industrial meter CH₄ and CO₂ emissions increased by an average of 173 percent across the time
16 series, compared to the previous Inventory. The increase in both CH₄ and CO₂ emissions is due to differences in the
17 EFs used in the current Inventory and the previous Inventory. The previous inventory used a lower EF (based on
18 commercial meter measurements only) and applied that EF to both commercial and industrial meter counts. The
19 updated methodology uses commercial meter data from both the 2009 and 2019 GTI studies to develop an EF that
20 is applied to commercial meter counts, and uses industrial meter data from both the 2009 (leak emissions only)
21 and GTI 2019 studies to develop an EF that is applied to industrial meter counts. No change was made to the
22 activity data approach.

23 EPA received comments on the *Customer Meters Memo* and continues to seek feedback on this update. These
24 comments included a recommendation to delay updates until additional data could be collected. EPA seeks
25 feedback on upcoming or ongoing research studies or other data collection efforts that could be used to update
26 emission estimates for this source. In addition, the largest source of emissions from customer meters in the 2009
27 study was vented emissions from industrial meters, with an average emission factor per meter of 3,487 kg/year,
28 compared with an average emission factor per industrial meter from leaks of 105 kg/year. Venting emissions were
29 observed and measured at 2 out of the 6 companies participating in the 2009 GTI study. This source of emissions
30 was not studied in the 2019 GTI study. The emission estimates for industrial meters presented here include only
31 leak emissions. EPA seeks stakeholder feedback on upcoming or ongoing research studies that measure vented
32 emissions from industrial meters.

33 **Table 3-83: Commercial and Industrial Meter National Emissions (Metric Tons CH₄)**

Source	1990	2005	2015	2016	2017	2018	2019
Commercial Meters	99,129	121,634	127,615	128,108	128,698	129,130	129,796

Industrial Meters	22,926	21,653	19,775	19,828	19,419	19,426	19,239
Total	122,055	143,287	147,390	147,936	148,118	148,555	149,036
<i>Previous Estimate</i>	43,362	52,605	54,919	55,129	55,324	56,140	NA

NA (Not Applicable)

1 **Table 3-84: Commercial and Industrial Meter National Emissions (Metric Tons CO₂)**

Source	1990	2005	2015	2016	2017	2018	2019
Commercial Meters	2,919	3,581	3,757	3,772	3,789	3,802	3,822
Industrial Meters	675	638	582	584	572	572	566
Total	3,594	4,219	4,340	4,356	4,361	4,374	4,388
<i>Previous Estimate</i>	1,277	1,549	1,617	1,623	1,629	1,653	NA

NA (Not Applicable)

2 Planned Improvements

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

4 Mud Degassing

5 As part of the stakeholder process for the current (1990 to 2019) Inventory, EPA developed new CH₄ emission
6 estimates for mud degassing in the exploration segment. To date, the Inventory has not included emissions from
7 exploration mud degassing. EPA's considerations for this source are documented in the EPA memorandum
8 *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2019: Update Under Consideration for Mud Degassing*
9 *Emissions (Mud Degassing memo)*. EPA estimated preliminary emissions using CH₄ emission factors from EPA (EPA
10 1977) and well counts data from Enverus DrillingInfo data. In estimating national preliminary CH₄ estimates for
11 mud degassing, EPA incorporated an estimate of 26 days as an average drilling duration and 61.2 percent (by
12 weight) as the default CH₄ content of natural gas. EPA developed preliminary national estimates for 2 different
13 scenarios: 1) EPA assumed 80 percent of drilling operations were performed using water-based muds and the
14 remaining 20 percent used oil-based muds; and 2) EPA assumed 100 percent of drilling operations were performed
15 using water-based muds. Methane emissions from mud degassing averaged 73 kt over the time series for scenario
16 1 and 86 kt for scenario 2 (100 percent water-based muds), or around 2 MMT CO₂ Eq. This update would increase
17 emissions from the exploration segment but would have a small impact on overall CH₄ emissions from natural gas
18 systems.

19 EPA notes that estimates for mud degassing using similar assumptions are included in several other bottom-up
20 inventories for greenhouse gases and other gases, including New York state, and the NEI. In response to
21 stakeholder feedback on the *Mud Degassing memo*, EPA continues to seek feedback on alternate assumptions for
22 borehole diameter and porosity, average total drilling days and drilling days in the producing formation, CH₄
23 content of the gas, and the effect of balanced and over-balanced mud degassing systems. EPA will further assess
24 the average drilling duration in an updated Enverus DrillingInfo dataset. Additionally, EPA is considering developing
25 CO₂ estimates for onshore production mud degassing using the CH₄ estimates and a ratio of CO₂-to-CH₄.

26 **Table 3-85: Draft Mud Degassing National CH₄ Emissions – Not Included in Totals (Metric**
27 **Tons CH₄)**

Source	1990	2005	2015	2016	2017	2018	2019
Scenario 1 (80/20)	95,133	146,766	18,211	11,736	19,301	19,301	19,301
Scenario 2 (100)	111,922	172,666	21,425	13,808	22,707	22,707	22,707
<i>Previous Estimate</i>	NA	NA	NA	NA	NA	NA	NA

NA (Not Applicable)

Scenario 1 (80/20) – 80% water-based mud usage and 20% oil-based mud usage

Scenario 2 (100) – 100% water-based mud usage

1 Underground Storage Wells

2 As part of the stakeholder process for the current (1990 to 2019) Inventory, EPA developed draft CH₄ emission
3 estimates for underground storage well leak emissions in the transmission and storage segment. EPA's
4 considerations for this source are documented in the EPA memorandum *Inventory of U. S. Greenhouse Gas*
5 *Emissions and Sinks 1990-2019: Updates Under Consideration to Natural Gas Underground Storage Well Emissions*
6 *(Underground Storage Wells memo)*.⁹¹ EPA presented multiple options to calculate storage well emissions in the
7 *Underground Storage Wells memo*, and estimated emissions here using a 'per station' EF along with underground
8 storage station counts.

9 To develop the estimates presented below, EPA calculated a 'per station' weighted average EF using measurement
10 data from a GSI 2019 study, GHGRP wellhead component counts, and field type distributions from EIA; this EF was
11 applied over the time series. The current Inventory uses an EF from the 1996 GRI/EPA study. EPA updated the
12 activity approach here to use underground storage station counts. The current Inventory uses a storage well count
13 from 1992 and scales that value based on residential gas consumption. EPA has not received feedback on the
14 *Underground Storage Wells memo* to date and is still seeking feedback on these considerations.

15 **Table 3-86: Draft Underground Storage Wells National Emissions – Not Included in Totals**
16 **(Metric Tons CH₄)**

Source	1990	2005	2015	2016	2017	2018	2019
Storage Wells	9,004	9,627	7,269	7,214	7,195	7,139	7,139
Previous Estimate	13,565	14,910	14,250	13,428	13,629	15,365	NA

NA (Not Applicable)

Note: The Previous Estimate shows the routine storage well leak emissions only, to allow for a direct comparison, and does not include the Aliso Canyon leak emissions that occurred in 2015 and 2016 and that are included in the Inventory under the storage wells line item.

17 CO₂ Uncertainty

18 As part of the stakeholder process for the current (2021) Inventory, EPA developed a draft update to the
19 uncertainty analysis for CO₂. The updated under consideration is documented in the memoranda, *Inventory of U.S.*
20 *Greenhouse Gas Emissions and Sinks 1990-2019: Update Under Consideration for Natural Gas and Petroleum*
21 *Systems CO₂ Uncertainty Estimates*.⁹² EPA continues to seek stakeholder feedback on this update.

22 Upcoming Data, and Additional Data that Could Inform the Inventory

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

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

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

- 32 • Tank malfunction and control efficiency data.

⁹¹ Stakeholder materials, including draft memoranda for the current (i.e. 1990 to 2019) Inventory are available at
<<https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems>>

⁹² <https://www.epa.gov/sites/production/files/2020-11/documents/ghgi-webinar-nov2020-co2.pdf>

- 1 • Activity data and emissions data for production facilities that do not report to GHGRP.
 - 2 • Natural gas leaks at point of use estimates.
 - 3 • Anomalous leak events, such as a 2018 well blowout in Ohio.
- 4 EPA will continue to seek available data on these and other sources as part of the process to update the Inventory.

5 3.8 Abandoned Oil and Gas Wells (CRF Source 6 Categories 1B2a and 1B2b)

7 For this Public Review draft, the 1990 to 2018 time series has not been updated, and the 2018 data from the
8 previous (1990 to 2018) Inventory have been used as a proxy for 2019. The time series will be updated with the
9 most recent activity data for the final Inventory.

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

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

16 The U.S. population of abandoned wells is around 3.2 million (with around 2.6 million abandoned oil wells and 0.6
17 million abandoned gas wells). Abandoned wells emit both CH₄ and CO₂. Wells that are plugged have much lower
18 average emissions than wells that are unplugged (less than 1 kg CH₄ per well per year, versus over 100 kg CH₄ per
19 well per year). Around a third of the abandoned well population in the United States is plugged. This fraction has
20 increased over the time series (from around 19 percent in 1990) as more wells fall under regulations and programs
21 requiring or promoting plugging of abandoned wells.

22 *Abandoned oil wells.* Abandoned oil wells emitted 227 kt CH₄ and 5 kt CO₂ in 2019. Emissions of both gases
23 decreased by 1 percent from 1990, while the total population of abandoned oil wells increased 27 percent.

24 *Abandoned gas wells.* Abandoned gas wells emitted 54 kt CH₄ and 2 kt CO₂ in 2019. Emissions of both gases
25 increased by 50 percent from 1990, as the total population of abandoned gas wells increased 79 percent.

26 **Table 3-87: CH₄ Emissions from Abandoned Oil and Gas Wells (MMT CO₂ Eq.)**

Activity	1990	2005	2015	2016	2017	2018	2019
Abandoned Oil Wells	5.7	5.9	5.8	5.8	5.7	5.7	5.7
Abandoned Gas Wells	0.9	1.1	1.3	1.4	1.4	1.4	1.4
Total	6.6	6.9	7.1	7.2	7.1	7.0	7.0

Note: Totals may not sum due to independent rounding.

27 **Table 3-88: CH₄ Emissions from Abandoned Oil and Gas Wells (kt)**

Activity	1990	2005	2015	2016	2017	2018	2019
Abandoned Oil Wells	227	236	233	234	227	227	227
Abandoned Gas Wells	36	43	53	55	55	54	54
Total	263	278	286	289	282	281	281

Note: Totals may not sum due to independent rounding.

28 **Table 3-89: CO₂ Emissions from Abandoned Oil and Gas Wells (MMT CO₂)**

Activity	1990	2005	2015	2016	2017	2018	2019
Abandoned Oil Wells	+	+	+	+	+	+	+
Abandoned Gas Wells	+	+	+	+	+	+	+
Total	+						

+ Does not exceed 0.05 MMT CO₂.

1 **Table 3-90: CO₂ Emissions from Abandoned Oil and Gas Wells (kt)**

Activity	1990	2005	2015	2016	2017	2018	2019
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.

2 Methodology

3 EPA developed abandoned well CH₄ emission factors using data from Kang et al. (2016) and Townsend-Small et al.
 4 (2016). Plugged and unplugged abandoned well CH₄ emission factors were developed at the national-level
 5 (emission data from Townsend-Small et al.) and for the Appalachia region (using emission data from
 6 measurements in Pennsylvania and Ohio conducted by Kang et al. and Townsend-Small et al., respectively). The
 7 Appalachia region emissions factors were applied to abandoned wells in states in the Appalachian basin region,
 8 and the national-level emission factors were applied to all other abandoned wells.

9 EPA developed abandoned well CO₂ emission factors using the CH₄ emission factors and an assumed ratio of CO₂-
 10 to-CH₄ gas content, similar to the approach used to calculate CO₂ emissions for many sources in Petroleum
 11 Systems and Natural Gas Systems. For abandoned oil wells, EPA used the Petroleum Systems default production
 12 segment associated gas ratio of 0.020 MT CO₂/MT CH₄, which was derived through API TankCalc modeling runs. For
 13 abandoned gas wells, EPA used the Natural Gas Systems default production segment CH₄ and CO₂ gas content
 14 values (GRI/EPA 1996, GTI 2001) to develop a ratio of 0.044 MT CO₂/MT CH₄.

15 The total population of abandoned wells over the time series was estimated using historical data and DrillingInfo
 16 data. For the most recent year of the Inventory time series (year 2018), the prior year total counts are used as
 17 surrogate data, as the DrillingInfo query approach for the most recent year would likely overestimate abandoned
 18 well counts, because many wells might be spud and not reporting production—not because they are
 19 dry/abandoned, but due to the time required for completion. The abandoned well population was then split into
 20 plugged and unplugged wells by assuming that all abandoned wells were unplugged in 1950, using year-specific
 21 Drilling info data to calculate the fraction of abandoned wells plugged in 2016 (31 percent) and 2017 and 2018 (34
 22 percent in both years), and applying linear interpolation between the 1950 value and 2016 value to calculate the
 23 plugged fraction for intermediate years. See the memorandum *Inventory of U.S. Greenhouse Gas Emissions and*
 24 *Sinks 1990-2016: Abandoned Wells in Natural Gas and Petroleum Systems (2018 Abandoned Wells Memo)* for
 25 details.⁹³

26 Abandoned Oil Wells

27 **Table 3-91: Abandoned Oil Wells Activity Data, CH₄ and CO₂ Emissions (Metric Tons)**

Source	1990	2005	2015	2016	2017	2018	2019
Plugged abandoned oil wells	387,506	617,887	780,434	801,199	882,850	889,068	889,068
Unplugged abandoned oil wells	1,688,445	1,789,493	1,792,458	1,800,130	1,750,802	1,744,585	1,744,585
Total Abandoned Oil Wells	2,075,950	2,407,380	2,572,893	2,601,329	2,633,652	2,633,652	2,633,652

⁹³ See <<https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems>>.

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	577	592	652	657	657
CH ₄ from unplugged abandoned oil wells (MT)	226,740	235,212	232,197	233,191	226,801	225,995	225,995
Total CH₄ from Abandoned oil wells (MT)	227,058	235,688	232,773	233,782	227,453	226,652	226,652
Total CO₂ from Abandoned oil wells (MT)	4,607	4,782	4,723	4,744	4,615	4,599	4,599

1 Abandoned Gas Wells

2 **Table 3-92: Abandoned Gas Wells Activity Data, CH₄ and CO₂ Emissions (Metric Tons)**

Source	1990	2005	2015	2016	2017	2018	2019
Plugged abandoned gas wells	60,126	104,652	162,215	171,979	193,375	194,736	194,736
Unplugged abandoned gas wells	261,982	303,089	372,566	386,402	383,486	382,124	382,124
Total Abandoned Gas Wells	322,108	407,741	534,781	558,381	576,861	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	155	164	185	186	186
CH ₄ from unplugged abandoned gas wells (MT)	36,199	42,582	52,919	54,884	54,470	54,276	54,276
Total CH₄ from abandoned gas wells (MT)	36,253	42,679	53,074	55,048	54,654	54,462	54,462
Total CO₂ from abandoned gas wells (MT)	1,589	1,870	2,326	2,413	2,395	2,387	2,387

3 Uncertainty and Time-Series Consistency -TO BE UPDATED

4 To characterize uncertainty surrounding estimates of abandoned well emissions, EPA conducted a quantitative
5 uncertainty analysis using the IPCC Approach 2 methodology (Monte Carlo simulation technique). See the *2018*
6 *Abandoned Wells Memo* for details of the uncertainty analysis methods. EPA used Microsoft Excel's @RISK add-in
7 tool to estimate the 95 percent confidence bound around total methane emissions from abandoned oil and gas
8 wells in year 2018, then applied the calculated bounds to both CH₄ and CO₂ emissions estimates for each
9 population. The @RISK add-in provides for the specification of probability density functions (PDFs) for key variables
10 within a computational structure that mirrors the calculation of the inventory estimate. EPA used measurement
11 data from the Kang et al. (2016) and Townsend-Small et al. (2016) studies to characterize the CH₄ emission factor
12 PDFs. For activity data inputs (e.g., total count of abandoned wells, split between plugged and unplugged), EPA
13 assigned default uncertainty bounds of +/- 10 percent based on expert judgment.

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

1 uncertainty, data representativeness, measurement errors, misreporting or misclassification.

2 The results presented below in Table 3-93 provide the 95 percent confidence bound within which actual emissions
 3 from abandoned oil and gas wells are likely to fall for the year 2018, using the recommended IPCC methodology.
 4 Abandoned oil well CH₄ emissions in 2018 were estimated to be between 1.0 and 18.1 MMT CO₂ Eq., while
 5 abandoned gas well CH₄ emissions were estimated to be between 0.2 and 4.3 MMT CO₂ Eq. at a 95 percent
 6 confidence level. Uncertainty bounds for other years of the time series have not been calculated, but uncertainty is
 7 expected to vary over the time series.

8 **Table 3-93: Approach 2 Quantitative Uncertainty Estimates for CH₄ and CO₂ Emissions from**
 9 **Petroleum and Natural Gas Systems (MMT CO₂ 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
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 CH₄ 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.

10 To calculate a time series of emissions for abandoned wells, EPA developed annual activity data for 1990 through
 11 2018 by summing an estimate of total abandoned wells not included in recent databases, to an annual estimate of
 12 abandoned wells in the Enverus DrillingInfo data set (with year 2017 estimates used as surrogates for year 2018
 13 data). As discussed above, the abandoned well population was split into plugged and unplugged wells by assuming
 14 that all abandoned wells were unplugged in 1950, using year-specific Drilling info data to calculate the fraction of
 15 abandoned wells plugged in 2016 through 2018, and applying linear interpolation between the 1950 value and
 16 2016 value to calculate plugged fraction for intermediate years. The same emission factors were applied to the
 17 corresponding categories for each year of the time series.

18 QA/QC and Verification Discussion

19 The emission estimates in the Inventory are continually being reviewed and assessed to determine whether
 20 emission factors and activity factors accurately reflect current industry practices. A QA/QC analysis was performed
 21 for data gathering and input, documentation, and calculation. QA/QC checks are consistently conducted to
 22 minimize human error in the model calculations. EPA performs a thorough review of information associated with
 23 new studies to assess whether the assumptions in the Inventory are consistent with industry practices and
 24 whether new data is available that could be considered for updates to the estimates. As in previous years, EPA
 25 conducted early engagement and communication with stakeholders on updates prior to public review. EPA held
 26 stakeholder webinars on greenhouse gas data for oil and gas in September and November of 2020.

27 Recalculations Discussion -TO BE UPDATED FOR FINAL 28 INVENTORY REPORT

29 The counts of national abandoned wells were recalculated across the time series to use the latest DrillingInfo data,
 30 which resulted in minor changes to the total abandoned well population and the allocation between petroleum
 31 and natural gas systems. The minor changes resulted from changes to the year-specific data for 1990 to 2017 as
 32 processed from DrillingInfo, which led EPA to recalculate the estimate of historical wells not included in the
 33 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

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 UNFCCC⁹⁴ request that information be provided on precursor greenhouse gases, which include carbon monoxide (CO), nitrogen oxides (NO_x), non-CH₄ volatile organic compounds (NMVOCs), and sulfur dioxide (SO₂). 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 SO₂, 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 2019 are reported in Table 3-94. Sulfur dioxide emissions are presented in Section 2.3 of the Trends chapter and Annex 6.3.

Table 3-94: NO_x, CO, and NMVOC Emissions from Energy-Related Activities (kt)

Gas/Activity	1990	2005	2015	2016	2017	2018	2019
NO_x	21,106	16,602	9,429	8,268	7,928	7,471	7,080
Mobile Fossil Fuel Combustion	10,862	10,295	5,634	4,739	4,563	4,123	3,862
Stationary Fossil Fuel Combustion	10,023	5,858	3,084	2,856	2,728	2,711	2,581
Oil and Gas Activities	139	321	622	594	565	565	565
Waste Combustion	82	128	88	80	71	71	71
<i>International Bunker Fuels^a</i>	1,956	1,704	1,363	1,470	1,481	1,462	1,297
CO	125,640	64,985	38,521	34,461	33,582	32,048	31,208
Mobile Fossil Fuel Combustion	119,360	58,615	32,635	28,789	28,124	26,590	25,749
Stationary Fossil Fuel Combustion	5,000	4,648	3,688	3,690	3,692	3,692	3,692
Waste Combustion	978	1,403	1,576	1,375	1,175	1,175	1,175
Oil and Gas Activities	302	318	622	607	592	592	592
<i>International Bunker Fuels^a</i>	103	133	144	150	156	160	157
NMVOCs	12,620	7,191	6,738	5,941	5,626	5,410	5,304
Mobile Fossil Fuel Combustion	10,932	5,724	3,458	2,873	2,758	2,543	2,437
Oil and Gas Activities	554	510	2,656	2,459	2,262	2,262	2,262
Stationary Fossil Fuel Combustion	912	716	493	489	496	496	496
Waste Combustion	222	241	132	121	109	109	109
<i>International Bunker Fuels^a</i>	57	54	47	50	51	51	46

⁹⁴ See <<http://unfccc.int/resource/docs/2013/cop19/eng/10a03.pdf>>.

Note: Totals may not sum due to independent rounding.

^a These values are presented for informational purposes only and are not included in totals.

1 Methodology

2 Emission estimates for 1990 through 2019 were obtained from data published on the National Emission Inventory
3 (NEI) Air Pollutant Emission Trends web site (EPA 2020), and disaggregated based on EPA (2003). Emissions were
4 calculated either for individual categories or for many categories combined, using basic activity data (e.g., the
5 amount of raw material processed) as an indicator of emissions. National activity data were collected for individual
6 applications from various agencies.

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

12 Uncertainty and Time-Series Consistency

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

15 Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990
16 through 2019. Details on the emission trends through time are described in more detail in the Methodology
17 section, above.

18 3.10 International Bunker Fuels (CRF Source 19 Category 1: Memo Items)

20 Emissions resulting from the combustion of fuels used for international transport activities, termed international
21 bunker fuels under the UNFCCC, are not included in national emission totals, but are reported separately based
22 upon location of fuel sales. The decision to report emissions from international bunker fuels separately, instead of
23 allocating them to a particular country, was made by the Intergovernmental Negotiating Committee in establishing
24 the Framework Convention on Climate Change.⁹⁵ These decisions are reflected in the IPCC methodological
25 guidance, including IPCC (2006), in which countries are requested to report emissions from ships or aircraft that
26 depart from their ports with fuel purchased within national boundaries and are engaged in international transport
27 separately from national totals (IPCC 2006).⁹⁶

28 Two transport modes are addressed under the IPCC definition of international bunker fuels: aviation and marine.⁹⁷
29 Greenhouse gases emitted from the combustion of international bunker fuels, like other fossil fuels, include CO₂,
30 CH₄ and N₂O for marine transport modes, and CO₂ and N₂O for aviation transport modes. Emissions from ground

⁹⁵ 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).

⁹⁶ Note that the definition of international bunker fuels used by the UNFCCC differs from that used by the International Civil Aviation Organization.

⁹⁷ 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).

1 transport activities—by road vehicles and trains—even when crossing international borders are allocated to the
 2 country where the fuel was loaded into the vehicle and, therefore, are not counted as bunker fuel emissions.

3 The *2006 IPCC Guidelines* distinguish between three different modes of air traffic: civil aviation, military aviation,
 4 and general aviation. Civil aviation comprises aircraft used for the commercial transport of passengers and freight,
 5 military aviation comprises aircraft under the control of national armed forces, and general aviation applies to
 6 recreational and small corporate aircraft. The *2006 IPCC Guidelines* further define international bunker fuel use
 7 from civil aviation as the fuel combusted for civil (e.g., commercial) aviation purposes by aircraft arriving or
 8 departing on international flight segments. However, as mentioned above, and in keeping with the *2006 IPCC*
 9 *Guidelines*, only the fuel purchased in the United States and used by aircraft taking-off (i.e., departing) from the
 10 United States are reported here. The standard fuel used for civil and military aviation is kerosene-type jet fuel,
 11 while the typical fuel used for general aviation is aviation gasoline.⁹⁸

12 Emissions of CO₂ from aircraft are essentially a function of fuel consumption. Nitrous oxide emissions also depend
 13 upon engine characteristics, flight conditions, and flight phase (i.e., take-off, climb, cruise, decent, and landing).
 14 Recent data suggest that little or no CH₄ is emitted by modern engines (Anderson et al. 2011), and as a result, CH₄
 15 emissions from this category are reported as zero. In jet engines, N₂O is primarily produced by the oxidation of
 16 atmospheric nitrogen, and the majority of emissions occur during the cruise phase.

17 International marine bunkers comprise emissions from fuels burned by ocean-going ships of all flags that are
 18 engaged in international transport. Ocean-going ships are generally classified as cargo and passenger carrying,
 19 military (i.e., U.S. Navy), fishing, and miscellaneous support ships (e.g., tugboats). For the purpose of estimating
 20 greenhouse gas emissions, international bunker fuels are solely related to cargo and passenger carrying vessels,
 21 which is the largest of the four categories, and military vessels. Two main types of fuels are used on sea-going
 22 vessels: distillate diesel fuel and residual fuel oil. Carbon dioxide is the primary greenhouse gas emitted from
 23 marine shipping.

24 Overall, aggregate greenhouse gas emissions in 2019 from the combustion of international bunker fuels from both
 25 aviation and marine activities were 117.2 MMT CO₂ Eq., or 12.1 percent above emissions in 1990 (see Table 3-95
 26 and Table 3-96). Emissions from international flights and international shipping voyages departing from the United
 27 States have increased by 112.5 percent and decreased by 46.1 percent, respectively, since 1990. The majority of
 28 these emissions were in the form of CO₂; however, small amounts of CH₄ (from marine transport modes) and N₂O
 29 were also emitted.⁹⁹

30 **Table 3-95: CO₂, CH₄, and N₂O Emissions from International Bunker Fuels (MMT CO₂ Eq.)**

Gas/Mode	1990	2005	2015	2016	2017	2018	2019
CO₂	103.5	113.2	110.8	116.5	120.0	122.0	116.1
Aviation	38.0	60.1	71.9	74.1	77.7	80.8	80.8
Commercial	30.0	55.6	68.6	70.8	74.5	77.7	77.7
Military	8.1	4.5	3.3	3.3	3.2	3.1	3.1
Marine	65.4	53.1	38.9	42.4	42.3	41.2	35.2
CH₄	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
N₂O	0.9	1.0	1.0	1.0	1.1	1.1	1.0
Aviation	0.4	0.6	0.7	0.7	0.7	0.8	0.8
Marine	0.5	0.4	0.3	0.3	0.3	0.3	0.3
Total	104.5	114.3	111.9	117.6	121.2	123.2	117.2

⁹⁸ Naphtha-type jet fuel was used in the past by the military in turbojet and turboprop aircraft engines.

⁹⁹ Military marine and military aircraft bunker fuel consumption data from the Defense Fuels Automated Management System (DLA Energy 2020) and aviation emission estimates from the Aviation Environmental Design Tool (FAA 2019) data for 2019 were proxied to 2018 values. Revised data from these sources will be integrated for Public Review.

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

^a CH₄ emissions from aviation are estimated to be zero.

1 **Table 3-96: CO₂, CH₄, and N₂O Emissions from International Bunker Fuels (kt)**

Gas/Mode	1990	2005	2015	2016	2017	2018	2019
CO₂	103,471	113,188	110,803	116,501	120,009	122,005	116,056
Aviation	38,034	60,125	71,942	74,059	77,696	80,788	80,814
Marine	65,437	53,063	38,862	42,442	42,313	41,217	35,242
CH₄	7	5	4	4	4	4	4
Aviation ^a	0	0	0	0	0	0	0
Marine	7	5	4	4	4	4	4
N₂O	3	3	3	3	4	4	3
Aviation	1	2	2	2	3	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 CH₄ emissions from aviation are estimated to be zero.

2 Methodology

3 Emissions of CO₂ were estimated by applying C content and fraction oxidized factors to fuel consumption activity
 4 data. This approach is analogous to that described under Section 3.1 – CO₂ from Fossil Fuel Combustion. Carbon
 5 content and fraction oxidized factors for jet fuel, distillate fuel oil, and residual fuel oil are the same as used for CO₂
 6 from Fossil Fuel Combustion and are presented in Annex 2.1, Annex 2.2, and Annex 3.8 of this Inventory. Density
 7 conversions were taken from Chevron (2000), ASTM (1989), and USAF (1998). Heat content for distillate fuel oil
 8 and residual fuel oil were taken from EIA (2020) and USAF (1998), and heat content for jet fuel was taken from EIA
 9 (2020).

10 A complete description of the methodology and a listing of the various factors employed can be found in Annex
 11 2.1. See Annex 3.8 for a specific discussion on the methodology used for estimating emissions from international
 12 bunker fuel use by the U.S. military.

13 Emission estimates for CH₄ and N₂O were calculated by multiplying emission factors by measures of fuel
 14 consumption by fuel type and mode. Emission factors used in the calculations of CH₄ and N₂O emissions were
 15 obtained from the *2006 IPCC Guidelines* (IPCC 2006). For aircraft emissions, the following value, in units of grams of
 16 pollutant per kilogram of fuel consumed (g/kg), was employed: 0.1 for N₂O (IPCC 2006). For marine vessels
 17 consuming either distillate diesel or residual fuel oil the following values (g/MJ), were employed: 0.32 for CH₄ and
 18 0.08 for N₂O. Activity data for aviation included solely jet fuel consumption statistics, while the marine mode
 19 included both distillate diesel and residual fuel oil.

20 Activity data on domestic and international aircraft fuel consumption were developed by the U.S. Federal Aviation
 21 Administration (FAA) using radar-informed data from the FAA Enhanced Traffic Management System (ETMS) for
 22 1990 and 2000 through 2018 as modeled with the Aviation Environmental Design Tool (AEDT).¹⁰⁰ This bottom-up
 23 approach is built from modeling dynamic aircraft performance for each flight occurring within an individual
 24 calendar year. The analysis incorporates data on the aircraft type, date, flight identifier, departure time, arrival
 25 time, departure airport, arrival airport, ground delay at each airport, and real-world flight trajectories. To generate
 26 results for a given flight within AEDT, the radar-informed aircraft data is correlated with engine and aircraft
 27 performance data to calculate fuel burn and exhaust emissions. Information on exhaust emissions for in-
 28 production aircraft engines comes from the International Civil Aviation Organization (ICAO) Aircraft Engine

¹⁰⁰ For 2019, activity data on domestic and international aircraft fuel consumption developed by the U.S. Federal Aviation Administration (FAA) were not available for Public Review and were proxied to 2018 data.

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

3 International aviation CO₂ estimates for 1990 and 2000 through 2018 were obtained directly from FAA’s AEDT
 4 model (FAA 2019). The radar-informed method that was used to estimate CO₂ emissions for commercial aircraft
 5 for 1990 and 2000 through 2018 was not possible for 1991 through 1999 because the radar dataset was not
 6 available for years prior to 2000. FAA developed Official Airline Guide (OAG) schedule-informed inventories
 7 modeled with AEDT and great circle trajectories for 1990, 2000, and 2010. Because fuel consumption and CO₂
 8 emission estimates for years 1991 through 1999 are unavailable, consumption estimates for these years were
 9 calculated using fuel consumption estimates from the Bureau of Transportation Statistics (DOT 1991 through
 10 2013), adjusted based on 2000 through 2005 data. See Annex 3.3 for more information on the methodology for
 11 estimating emissions from commercial aircraft jet fuel consumption.

12 Data on U.S. Department of Defense (DoD) aviation bunker fuels and total jet fuel consumed by the U.S. military
 13 was supplied by the Office of the Under Secretary of Defense (Installations and Environment), DoD. Estimates of
 14 the percentage of each Service’s total operations that were international operations were developed by DoD.
 15 Military aviation bunkers included international operations, operations conducted from naval vessels at sea, and
 16 operations conducted from U.S. installations principally over international water in direct support of military
 17 operations at sea. Military aviation bunker fuel emissions were estimated using military fuel and operations data
 18 synthesized from unpublished data from DoD’s Defense Logistics Agency Energy (DLA Energy 2020). Together, the
 19 data allow the quantity of fuel used in military international operations to be estimated. Densities for each jet fuel
 20 type were obtained from a report from the U.S. Air Force (USAF 1998). Final jet fuel consumption estimates are
 21 presented in Table 3-97. See Annex 3.8 for additional discussion of military data.

22 **Table 3-97: Aviation Jet Fuel Consumption for International Transport (Million Gallons)**

Nationality	1990	2005	2015	2016	2017	2018	2019
U.S. and Foreign Carriers	3,222	5,983	7,383	7,610	8,011	8,352	8,352
U.S. Military	862	462	341	333	326	315	318
Total	4,084	6,445	7,725	7,943	8,338	8,667	8,670

Note: Totals may not sum due to independent rounding.

23 In order to quantify the civilian international component of marine bunker fuels, activity data on distillate diesel
 24 and residual fuel oil consumption by cargo or passenger carrying marine vessels departing from U.S. ports were
 25 collected for individual shipping agents on a monthly basis by the U.S. Customs and Border Protection. This
 26 information was then reported in unpublished data collected by the Foreign Trade Division of the U.S. Department
 27 of Commerce’s Bureau of the Census (DOC 1991 through 2020) for 1990 through 2001, 2007 through 2019, and
 28 the Department of Homeland Security’s *Bunker Report* for 2003 through 2006 (DHS 2008). Fuel consumption data
 29 for 2002 was interpolated due to inconsistencies in reported fuel consumption data. Activity data on distillate
 30 diesel consumption by military vessels departing from U.S. ports were provided by DLA Energy (2020). The total
 31 amount of fuel provided to naval vessels was reduced by 21 percent to account for fuel used while the vessels
 32 were not-underway (i.e., in port). Data on the percentage of steaming hours underway versus not underway were
 33 provided by the U.S. Navy. These fuel consumption estimates are presented in Table 3-98Table 3-98.

1 **Table 3-98: Marine Fuel Consumption for International Transport (Million Gallons)**

Fuel Type	1990	2005	2015	2016	2017	2018	2019
Residual Fuel Oil	4,781	3,881	2,718	3,011	2,975	2,790	2,246
Distillate Diesel Fuel & Other	617	444	492	534	568	684	702
U.S. Military Naval Fuels	522	471	326	314	307	285	281
Total	5,920	4,796	3,536	3,858	3,850	3,759	3,229

Note: Totals may not sum due to independent rounding.

2 Uncertainty and Time-Series Consistency

3 Emission estimates related to the consumption of international bunker fuels are subject to the same uncertainties
 4 as those from domestic aviation and marine mobile combustion emissions; however, additional uncertainties
 5 result from the difficulty in collecting accurate fuel consumption activity data for international transport activities
 6 separate from domestic transport activities.¹⁰¹ For example, smaller aircraft on shorter routes often carry
 7 sufficient fuel to complete several flight segments without refueling in order to minimize time spent at the airport
 8 gate or take advantage of lower fuel prices at particular airports. This practice, called tankering, when done on
 9 international flights, complicates the use of fuel sales data for estimating bunker fuel emissions. Tankering is less
 10 common with the type of large, long-range aircraft that make many international flights from the United States,
 11 however. Similar practices occur in the marine shipping industry where fuel costs represent a significant portion of
 12 overall operating costs and fuel prices vary from port to port, leading to some tankering from ports with low fuel
 13 costs.

14 Uncertainties exist with regard to the total fuel used by military aircraft and ships. Total aircraft and ship fuel use
 15 estimates were developed from DoD records, which document fuel sold to the DoD Components (e.g., Army,
 16 Department of Navy and Air Force) from the Defense Logistics Agency Energy. These data may not include fuel
 17 used in aircraft and ships as a result of a Service procuring fuel from, selling fuel to, trading fuel with, or giving fuel
 18 to other ships, aircraft, governments, or other entities.

19 Additionally, there are uncertainties in historical aircraft operations and training activity data. Estimates for the
 20 quantity of fuel actually used in Navy and Air Force flying activities reported as bunker fuel emissions had to be
 21 estimated based on a combination of available data and expert judgment. Estimates of marine bunker fuel
 22 emissions were based on Navy vessel steaming hour data, which reports fuel used while underway and fuel used
 23 while not underway. This approach does not capture some voyages that would be classified as domestic for a
 24 commercial vessel. Conversely, emissions from fuel used while not underway preceding an international voyage
 25 are reported as domestic rather than international as would be done for a commercial vessel. There is uncertainty
 26 associated with ground fuel estimates for 1997 through 2019, including estimates for the quantity of jet fuel
 27 allocated to ground transportation. Small fuel quantities may have been used in vehicles or equipment other than
 28 that which was assumed for each fuel type.

29 There are also uncertainties in fuel end-uses by fuel type, emissions factors, fuel densities, diesel fuel sulfur
 30 content, aircraft and vessel engine characteristics and fuel efficiencies, and the methodology used to back-
 31 calculate the data set to 1990 using the original set from 1995. The data were adjusted for trends in fuel use based
 32 on a closely correlating, but not matching, data set. All assumptions used to develop the estimate were based on
 33 process knowledge, DoD data, and expert judgments. The magnitude of the potential errors related to the various
 34 uncertainties has not been calculated but is believed to be small. The uncertainties associated with future military
 35 bunker fuel emission estimates could be reduced through revalidation of assumptions based on data regarding
 36 current equipment and operational tempo, however, it is doubtful data with more fidelity exist at this time.

¹⁰¹ See uncertainty discussions under section 3.1 Carbon Dioxide Emissions from Fossil Fuel Combustion.

1 Although aggregate fuel consumption data have been used to estimate emissions from aviation, the recommended
2 method for estimating emissions of gases other than CO₂ in the *2006 IPCC Guidelines* (IPCC 2006) is to use data by
3 specific aircraft type, number of individual flights and, ideally, movement data to better differentiate between
4 domestic and international aviation and to facilitate estimating the effects of changes in technologies. The IPCC
5 also recommends that cruise altitude emissions be estimated separately using fuel consumption data, while
6 landing and take-off (LTO) cycle data be used to estimate near-ground level emissions of gases other than CO₂.¹⁰²
7 There is also concern regarding the reliability of the existing DOC (1991 through 2019) data on marine vessel fuel
8 consumption reported at U.S. customs stations due to the significant degree of inter-annual variation.
9 Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990
10 through 2019. Details on the emission trends through time are described in more detail in the Methodology
11 section, above.

12 QA/QC and Verification

13 In order to ensure the quality of the emission estimates from international bunker fuels, General (IPCC Tier 1) and
14 category-specific (Tier 2) Quality Assurance/Quality Control (QA/QC) procedures were implemented consistent
15 with the U.S. Inventory QA/QC plan outlined in Annex 8. The Tier 2 procedures that were implemented involved
16 checks specifically focusing on the activity data and emission factor sources and methodology used for estimating
17 CO₂, CH₄, and N₂O emissions from international bunker fuels in the United States. Emission totals for the different
18 sectors and fuels were compared and trends were investigated. No corrective actions were necessary.

19 Recalculations Discussion

20 EPA revised distillate fuel oil heat contents and carbon contents, which affect marine distillate fuel oil consumption
21 (EPA 2020). Revisions resulted in an average annual decrease of 7.8 MMT CO₂ Eq. in emissions from marine
22 residual and distillate fuel oil.

23 Planned Improvements

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

¹⁰² 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.

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 CO₂ in addition to CH₄ and N₂O already covered in this chapter. In line with the reporting requirements for inventories submitted under the UNFCCC, CO₂ emissions from biomass combustion have been estimated separately from fossil fuel CO₂ 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 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 CO₂ emissions to U.S. totals within the Land Use, Land-Use Change, and Forestry sector's approach.

Therefore, CO₂ 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 2019, total CO₂ emissions from the burning of woody biomass in the industrial, residential, commercial, and electric power sectors were approximately 216.5 MMT CO₂ Eq. (216,533 kt) (see Table 3-99 and Table 3-100). As the largest consumer of woody biomass, the industrial sector was responsible for 61.3 percent of the CO₂ emissions from this source. The residential sector was the second largest emitter, constituting 25.2 percent of the total, while the commercial and electric power sectors accounted for the remainder.

Table 3-99: CO₂ Emissions from Wood Consumption by End-Use Sector (MMT CO₂ Eq.)

End-Use Sector	1990	2005	2015	2016	2017	2018	2019
Industrial	135.3	136.3	138.5	138.3	135.4	135.0	132.6
Residential	59.8	44.3	52.9	45.6	43.8	53.3	54.5
Commercial	6.8	7.2	8.2	8.6	8.6	8.7	8.7
Electric Power	13.3	19.1	25.1	23.1	23.6	22.8	20.7
Total	215.2	206.9	224.7	215.7	211.5	219.8	216.5

Table 3-100: CO₂ Emissions from Wood Consumption by End-Use Sector (kt)

End-Use Sector	1990	2005	2015	2016	2017	2018	2019
Industrial	135,348	136,269	138,537	138,339	135,386	134,983	132,635
Residential	59,808	44,340	52,872	45,598	43,844	53,346	54,528
Commercial	6,779	7,218	8,176	8,635	8,634	8,669	8,693
Electric Power	13,252	19,074	25,146	23,140	23,647	22,795	20,677
Total	215,186	206,901	224,730	215,712	211,511	219,794	216,533

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 2019, the United States transportation sector consumed an estimated 1,170.8 trillion Btu of ethanol (97 percent of total), and as a result, produced approximately 80.2 MMT CO₂ Eq. (80,151 kt) (see Table 3-101 and Table 3-102) of CO₂ 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.

1 **Table 3-101: CO₂ Emissions from Ethanol Consumption (MMT CO₂ Eq.)**

End-Use Sector	1990	2005	2015	2016	2017	2018	2019
Transportation ^a	4.1	21.8	76.6	79.4	80.2	78.6	80.2
Industrial	0.1	1.0	1.0	0.8	0.8	1.4	1.0
Commercial	0.1	0.1	1.4	1.1	1.1	1.9	1.4
Total	4.2	22.9	78.9	81.2	82.1	81.9	82.6

Note: Totals may not sum due to independent rounding.

^a See Annex 3.2, Table A-83 for additional information on transportation consumption of these fuels.

2 **Table 3-102: CO₂ Emissions from Ethanol Consumption (kt)**

End-Use Sector	1990	2005	2015	2016	2017	2018	2019
Transportation ^a	4,059	21,816	76,578	79,413	80,238	78,603	80,151
Industrial	105	999	958	756	782	1,404	1,028
Commercial	63	128	1,397	1,081	1,068	1,910	1,399
Total	4,227	22,943	78,934	81,250	82,088	81,917	82,578

Note: Totals may not sum due to independent rounding.

^a See Annex 3.2, Table A-83 for additional information on transportation consumption of these fuels.

3 The transportation sector is assumed to be responsible for all of the biodiesel consumption in the United States
 4 (EIA 2020). Biodiesel is currently produced primarily from soybean oil, but it can be produced from a variety of
 5 biomass feedstocks including waste oils, fats and greases. Biodiesel for transportation use appears in low-level
 6 blends (less than 5 percent) with diesel fuel, high-level blends (between 6 and 20 percent) with diesel fuel, and 100
 7 percent biodiesel (EIA 2020b).

8 In 2019, the United States consumed an estimated 231.3 trillion Btu of biodiesel, and as a result, produced
 9 approximately 17.1 MMT CO₂ Eq. (17,080 kt) (see Table 3-103 and Table 3-104) of CO₂ emissions. Biodiesel
 10 production and consumption has grown significantly since 2001 due to the favorable economics of blending
 11 biodiesel into diesel and federal policies that have encouraged use of renewable fuels (EIA 2020b). There was no
 12 measured biodiesel consumption prior to 2001 EIA (2020).

13 **Table 3-103: CO₂ Emissions from Biodiesel Consumption (MMT CO₂ Eq.)**

End-Use Sector	1990	2005	2015	2016	2017	2018	2019
Transportation ^a	NO	0.9	14.1	19.6	18.7	17.9	17.1
Total	NO	0.9	14.1	19.6	18.7	17.9	17.1

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.

14 **Table 3-104: CO₂ Emissions from Biodiesel Consumption (kt)**

End-Use Sector	1990	2005	2015	2016	2017	2018	2019
Transportation ^a	NO	856	14,077	19,648	18,705	17,936	17,080
Total	NO	856	14,077	19,648	18,705	17,936	17,080

Note: Totals may not sum due to independent rounding.

NO (Not Occurring)

^a See Annex 3.2, Table A-83 for additional information on transportation consumption of these fuels.

15 Methodology

16 Woody biomass emissions were estimated by applying two gross heat contents from EIA (Lindstrom 2006) to U.S.
 17 consumption data (EIA 2020) (see Table 3-105), provided in energy units for the industrial, residential, commercial,
 18 and electric power sectors. One heat content (16.95 MMBtu/MT wood and wood waste) was applied to the
 19 industrial sector's consumption, while the other heat content (15.43 MMBtu/MT wood and wood waste) was

1 applied to the consumption data for the other sectors. An EIA emission factor of 0.434 MT C/MT wood (Lindstrom
 2 2006) was then applied to the resulting quantities of woody biomass to obtain CO₂ emission estimates. The woody
 3 biomass is assumed to contain black liquor and other wood wastes, have a moisture content of 12 percent, and
 4 undergo complete combustion to be converted into CO₂.

5 The amount of ethanol allocated across the transportation, industrial, and commercial sectors was based on the
 6 sector allocations of ethanol-blended motor gasoline. The sector allocations of ethanol-blended motor gasoline
 7 were determined using a bottom-up analysis conducted by EPA, as described in the Methodology section of Fossil
 8 Fuel Combustion. Total U.S. ethanol consumption from EIA (2020) was allocated to individual sectors using the
 9 same sector allocations as ethanol-blended motor gasoline. The emissions from ethanol consumption were
 10 calculated by applying an emission factor of 18.67 MMT C/Qbtu (EPA 2010) to adjusted ethanol consumption
 11 estimates (see Table 3-106). The emissions from biodiesel consumption were calculated by applying an emission
 12 factor of 20.1 MMT C/Qbtu (EPA 2010) to U.S. biodiesel consumption estimates that were provided in energy units
 13 (EIA 2020) (see Table 3-107).¹⁰³

14 **Table 3-105: Woody Biomass Consumption by Sector (Trillion Btu)**

End-Use Sector	1990	2005	2015	2016	2017	2018	2019
Industrial	1,441.9	1,451.7	1,475.9	1,473.8	1,442.3	1,438.0	1,413.0
Residential	580.0	430.0	512.7	442.2	425.2	517.3	528.8
Commercial	65.7	70.0	79.3	83.7	83.7	84.1	84.3
Electric Power	128.5	185.0	243.9	224.4	229.3	221.1	200.5
Total	2,216.2	2,136.7	2,311.8	2,224.1	2,180.6	2,260.5	2,226.6

Note: Totals may not sum due to independent rounding.

15 **Table 3-106: Ethanol Consumption by Sector (Trillion Btu)**

End-Use Sector	1990	2005	2015	2016	2017	2018	2019
Transportation	59.3	318.7	1,118.6	1,160.0	1,172.1	1,148.2	1,170.8
Industrial	1.5	14.6	14.0	11.0	11.4	20.5	15.0
Commercial	0.9	1.9	20.4	15.8	15.6	27.9	20.4
Total	61.7	335.1	1,153.1	1,186.9	1,199.1	1,196.6	1,206.3

Note: Totals may not sum due to independent rounding.

16 **Table 3-107: Biodiesel Consumption by Sector (Trillion Btu)**

End-Use Sector	1990	2005	2015	2016	2017	2018	2019
Transportation	NO	11.6	190.6	266.1	253.3	242.9	231.3
Total	NO	11.6	190.6	266.1	253.3	242.9	231.3

Note: Totals may not sum due to independent rounding.

NO (Not Occurring)

17 Uncertainty and Time-Series Consistency

18 It is assumed that the combustion efficiency for woody biomass is 100 percent, which is believed to be an
 19 overestimate of the efficiency of wood combustion processes in the United States. Decreasing the combustion
 20 efficiency would decrease emission estimates for CO₂. Additionally, the heat content applied to the consumption
 21 of woody biomass in the residential, commercial, and electric power sectors is unlikely to be a completely accurate
 22 representation of the heat content for all the different types of woody biomass consumed within these sectors.

¹⁰³ CO₂ 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.

1 Emission estimates from ethanol and biodiesel production are more certain than estimates from woody biomass
2 consumption due to better activity data collection methods and uniform combustion techniques.

3 Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990
4 through 2019. Details on the emission trends through time are described in more detail in the Methodology
5 section, above.

6 Recalculations Discussion

7 EIA (2020) revised approximate heat rates for electricity and the heat content of electricity for noncombustible
8 renewable energy, which impacted wood energy consumption by the industrial sector from 2016 through 2018.
9 Revisions to biomass consumption resulted in an average annual decrease of 0.7 MMT CO₂ Eq. (0.3 percent).

10 Planned Improvements

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

13 The availability of facility-level combustion emissions through EPA's GHGRP will be examined to help better
14 characterize the industrial sector's energy consumption in the United States, and further classify woody biomass
15 consumption by business establishments according to industrial economic activity type. Most methodologies used
16 in EPA's GHGRP are consistent with IPCC, though for EPA's GHGRP, facilities collect detailed information specific to
17 their operations according to detailed measurement standards, which may differ with the more aggregated data
18 collected for the Inventory to estimate total, national U.S. emissions. In addition, and unlike the reporting
19 requirements for this chapter under the UNFCCC reporting guidelines, some facility-level fuel combustion
20 emissions reported under EPA's GHGRP may also include industrial process emissions.¹⁰⁴ In line with UNFCCC
21 reporting guidelines, fuel combustion emissions are included in this chapter, while process emissions are included
22 in the Industrial Processes and Product Use chapter of this report. In examining data from EPA's GHGRP that would
23 be useful to improve the emission estimates for the CO₂ from biomass combustion category, particular attention
24 will also be made to ensure time series consistency, as the facility-level reporting data from EPA's GHGRP are not
25 available for all inventory years as reported in this Inventory. Additionally, analyses will focus on aligning reported
26 facility-level fuel types and IPCC fuel types per the national energy statistics, ensuring CO₂ emissions from biomass
27 are separated in the facility-level reported data, and maintaining consistency with national energy statistics
28 provided by EIA. In implementing improvements and integration of data from EPA's GHGRP, the latest guidance
29 from the IPCC on the use of facility-level data in national inventories will be relied upon.¹⁰⁵

30 Currently emission estimates from biomass and biomass-based fuels included in this Inventory are limited to
31 woody biomass, ethanol, and biodiesel. Additional forms of biomass-based fuel consumption include biogas and
32 the biogenic components of MSW. EPA will examine EIA data on biogas to see if it can be included in future
33 inventories. EIA (2020) natural gas data already deducts biogas used in the natural gas supply, so no adjustments
34 are needed to the natural gas fuel consumption data to account for biogas. Sources of estimates for the biogenic
35 fraction of MSW will be examined, including the GHGRP, EIA data, and EPA MSW characterization data.

36 Carbon dioxide emissions from biomass used in the electric power sector are calculated using woody biomass
37 consumption data from EIA's *Monthly Energy Review* (EIA 2020), whereas non-CO₂ biomass emissions from the
38 electric power sector are estimated by applying technology and fuel use data from EPA's Clean Air Market Acid
39 Rain Program dataset (EPA 2020) to fuel consumption data from EIA (2020). There were significant discrepancies
40 identified between the EIA woody biomass consumption data and the consumption data estimated using EPA's
41 Acid Rain Program dataset (see the Methodology section for CH₄ and N₂O from Stationary Combustion). EPA will

¹⁰⁴ See <<https://unfccc.int/resource/docs/2013/cop19/eng/10a03.pdf#page=2>>.

¹⁰⁵ See <http://www.ipcc-nggip.iges.or.jp/public/tb/TFI_Technical_Bulletin_1.pdf>.

- 1 continue to investigate this discrepancy in order to apply a consistent approach to both CO₂ and non-CO₂ emission
- 2 calculations for woody biomass consumption in the electric power sector.