3. Energy

Energy-related activities were the primary sources of U.S. anthropogenic greenhouse gas emissions, accounting for 82.2 percent of total greenhouse gas emissions on a carbon dioxide (CO_2) equivalent basis in 2019.[1] This included 96.7, 40.6, and 9.5 percent of the nation's CO_2, methane (CH_4), and nitrous oxide (N_2O) emissions, respectively. Energy-related CO_2 emissions alone constituted 77.5 percent of U.S. greenhouse gas emissions from all sources on a CO_2-equivalent basis, while the non-CO_2 emissions from energy-related activities represented a much smaller portion of total national emissions (4.7 percent collectively).

Emissions from fossil fuel combustion comprise the vast majority of energy-related emissions, with CO_2 being the primary gas emitted (see Figure 3-1 and Figure 3-2). Globally, approximately 33,300 million metric tons (MMT) of CO_2 were added to the atmosphere through the combustion of fossil fuels in 2019, of which the United States accounted for approximately 15 percent.[2] Due to their relative importance over time (see Figure 3-2), fossil fuel combustion-related CO_2 emissions are considered separately and in more detail than other energy-related emissions (see Figure 3-3).

Fossil fuel combustion also emits CH_4 and N_2O. Stationary combustion of fossil fuels was the third largest source of N_2O 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 CH_4 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 CO_2 Eq.), which weight each gas by its global warming potential, or GWP, value. See section on global warming potentials in the Executive Summary.

[2] Global CO_2 emissions from fossil fuel combustion were taken from International Energy Agency *Energy related CO2 emissions, 1990-2019 – Charts* Available at: <https://www.iea.org/data-and-statistics/charts/energy-related-co2-emissions-1990-2019> (IEA 2020).

Figure 3-1: 2019 Energy Chapter Greenhouse Gas Sources

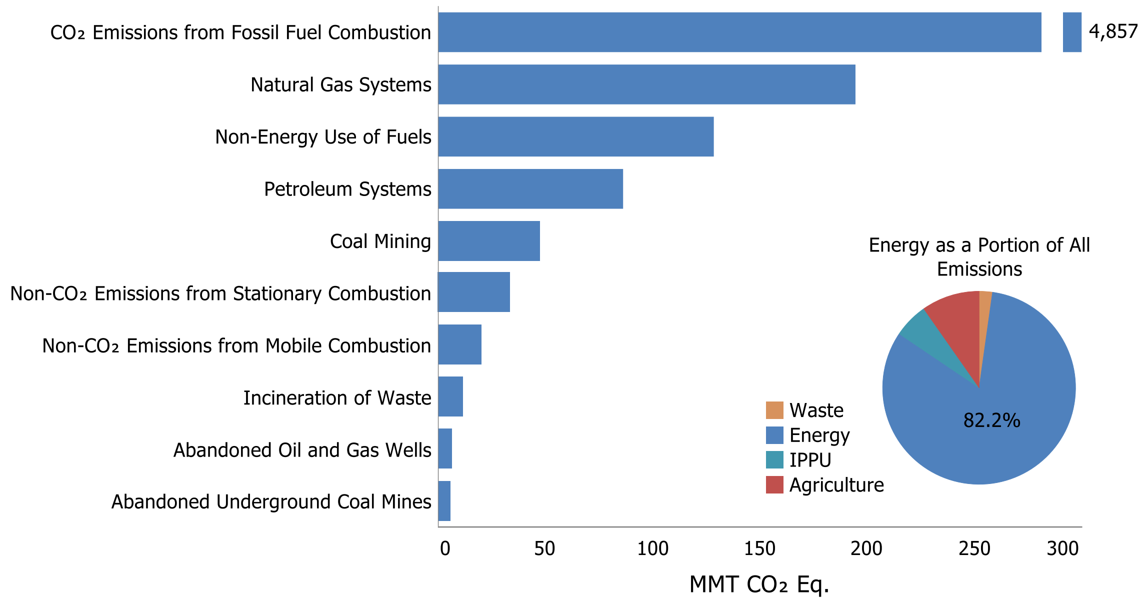


Figure 3-2: Trends in Energy Chapter Greenhouse Gas Sources

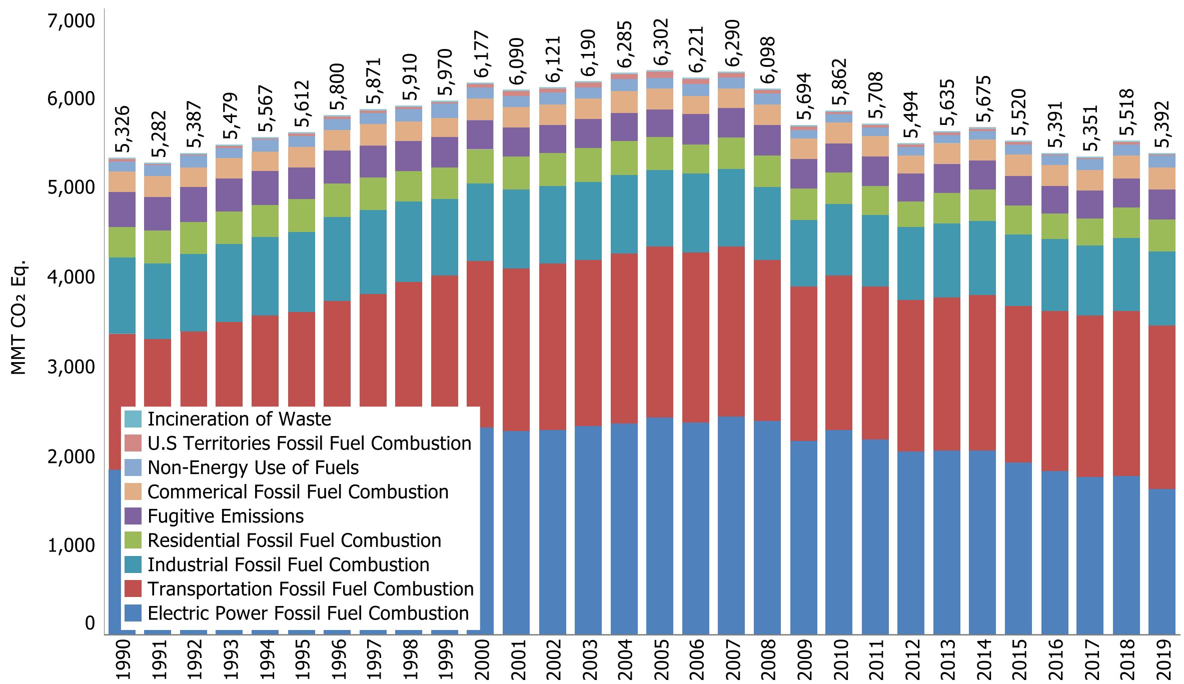


Figure 3-3: 2019 U.S. Fossil Carbon Flows

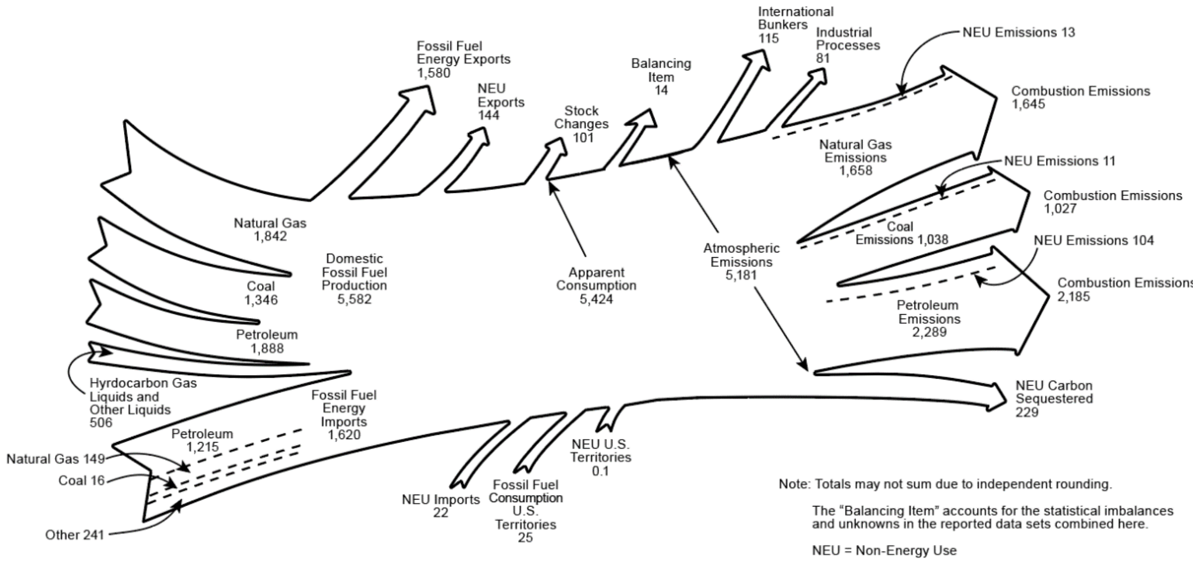


Table 3-1 summarizes emissions from the Energy sector in units of MMT CO_2 Eq., while unweighted gas emissions in kilotons (kt) are provided in Table 3-2. Overall, emissions due to energy-related activities were 5,392.3 MMT CO_2 Eq. in 2019,[3] an increase of 1.3 percent since 1990 and a decrease of 2.3 percent since 2018.

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

Gas/Source	1990	2005	2015	2016	2017	2018	2019
CO_2	**4,894.1**	**5,932.6**	**5,189.8**	**5,074.8**	**5,035.7**	**5,203.7**	**5,081.4**
Fossil Fuel Combustion	4,731.5	5,753.5	5,008.3	4,911.5	4,854.5	4,991.4	4,856.7
Transportation	*1,469.1*	*1,858.6*	*1,719.2*	*1,759.9*	*1,782.4*	*1,816.6*	*1,817.2*
Electric Power	*1,820.0*	*2,400.1*	*1,900.6*	*1,808.9*	*1,732.0*	*1,752.9*	*1,606.0*
Industrial	*853.8*	*852.9*	*797.3*	*792.5*	*790.1*	*813.6*	*822.5*
Residential	*338.6*	*358.9*	*317.3*	*292.8*	*293.4*	*338.1*	*336.8*
Commercial	*228.3*	*227.1*	*244.6*	*231.6*	*232.0*	*245.7*	*249.7*
U.S. Territories	*21.7*	*55.9*	*29.2*	*26.0*	*24.6*	*24.6*	*24.6*
Non-Energy Use of Fuels	112.8	129.1	108.5	99.8	113.5	129.7	128.8
Petroleum Systems	9.7	12.1	32.4	21.8	25.0	37.1	47.3
Natural Gas Systems	32.0	25.2	29.1	30.1	31.2	33.9	37.2
Incineration of Waste	8.1	12.7	11.5	11.5	11.5	11.5	11.5
Abandoned Oil and Gas Wells	+	+	+	+	+	+	+
Biomass-Wood[a]	*215.2*	*206.9*	*224.7*	*215.7*	*211.5*	*219.8*	*216.5*
International Bunker Fuels[b]	*103.5*	*113.2*	*110.9*	*116.6*	*120.1*	*122.1*	*116.1*
Biofuels-Ethanol[a]	*4.2*	*22.9*	*78.9*	*81.2*	*82.1*	*81.9*	*82.6*
Biofuels-Biodiesel[a]	*0.0*	*0.9*	*14.1*	*19.6*	*18.7*	*17.9*	*17.1*
CH_4	**361.3**	**293.3**	**277.4**	**264.9**	**266.6**	**267.0**	**267.6**
Natural Gas Systems	186.9	164.2	149.8	147.3	148.7	152.5	157.6
Coal Mining	96.5	64.1	61.2	53.8	54.8	52.7	47.4
Petroleum Systems	48.9	39.5	41.5	39.2	39.3	37.3	39.1
Stationary Combustion	8.6	7.8	8.5	7.9	7.6	8.5	8.7
Abandoned Oil and Gas Wells	6.8	7.2	7.4	7.4	7.2	7.3	6.6

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

Abandoned Underground Coal Mines	7.2		6.6		6.4	6.7	6.4	6.2	5.9
Mobile Combustion	6.4		4.0		2.6	2.5	2.5	2.4	2.4
Incineration of Waste	+		+		+	+	+	+	+
International Bunker Fuels[b]	*0.2*		*0.1*		*0.1*	*0.1*	*0.1*	*0.1*	*0.1*
N_2O	**70.3**		**76.3**		**52.6**	**51.2**	**48.6**	**47.4**	**43.2**
Stationary Combustion	25.1		34.4		30.5	30.0	28.4	28.2	24.9
Mobile Combustion	44.7		41.6		21.7	20.8	19.8	18.8	18.0
Incineration of Waste	0.5		0.4		0.3	0.3	0.3	0.3	0.3
Petroleum Systems	+		+		+	+	+	+	+
Natural Gas Systems	+		+		+	+	+	+	+
International Bunker Fuels[b]	*0.9*		*1.0*		*1.0*	*1.0*	*1.1*	*1.1*	*1.0*
Total	**5,325.6**		**6,302.3**		**5,519.8**	**5,390.9**	**5,351.0**	**5,518.1**	**5,392.3**

Note: Totals may not sum due to independent rounding.
+ Does not exceed 0.05 MMT CO_2 Eq.
[a] Emissions from Wood Biomass, Ethanol, and Biodiesel Consumption are not included specifically in summing Energy sector totals. Net carbon fluxes from changes in biogenic carbon reservoirs are accounted for in the estimates for LULUCF.
[b] Emissions from International Bunker Fuels are not included in totals. These values are presented for informational purposes only, in line with the *2006 IPCC Guidelines* and UNFCCC reporting obligations.

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

Gas/Source	1990		2005		2015	2016	2017	2018	2019
CO_2	**4,894,051**		**5,932,600**		**5,189,826**	**5,074,805**	**5,035,743**	**5,203,702**	**5,081,445**
Fossil Fuel Combustion	4,731,466		5,753,507		5,008,270	4,911,532	4,854,480	4,991,420	4,856,702
Non-Energy Use of Fuels	112,766		129,135		108,476	99,840	113,539	129,728	128,763
Petroleum Systems	9,709		12,059		32,412	21,847	24,979	37,115	47,269
Natural Gas Systems	32,042		25,179		29,127	30,054	31,200	33,885	37,234
Incineration of Waste	8,062		12,713		11,533	11,525	11,537	11,547	11,471
Abandoned Oil and Gas Wells	6		7		7	7	7	7	7
Biomass-Wood[a]	*215,186*		*206,901*		*224,730*	*215,712*	*211,511*	*219,794*	*216,533*
International Bunker Fuels[b]	*103,463*		*113,232*		*110,908*	*116,611*	*120,121*	*122,112*	*116,064*
Biofuels-Ethanol[a]	*4,227*		*22,943*		*78,934*	*81,250*	*82,088*	*81,917*	*82,578*
Biofuels-Biodiesel[a]	*0*		*856*		*14,077*	*19,648*	*18,705*	*17,936*	*17,080*
CH_4	**14,451**		**11,733**		**11,095**	**10,596**	**10,665**	**10,680**	**10,704**
Natural Gas Systems	7,478		6,567		5,994	5,894	5,949	6,101	6,305
Coal Mining	3,860		2,565		2,449	2,154	2,191	2,109	1,895
Petroleum Systems	1,955		1,579		1,659	1,568	1,574	1,492	1,563
Stationary Combustion	344		313		339	315	306	342	346
Abandoned Oil and Gas Wells	271		287		294	296	288	290	263
Abandoned Underground Coal Mines	288		264		256	268	257	247	237
Mobile Combustion	256		158		105	102	100	98	95
Incineration of Waste	+		+		+	+	+	+	+
International Bunker Fuels[b]	*7*		*5*		*4*	*4*	*4*	*4*	*4*
N_2O	**236**		**256**		**177**	**172**	**163**	**159**	**145**
Stationary Combustion	84		115		102	101	95	95	84

Mobile Combustion	150	139	73	70	67	63	60
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.

Emissions estimates reported in the Energy chapter from fossil fuel combustion and fugitive sources include those from all 50 states, including Hawaii and Alaska, and the District of Columbia. Emissions are also included from U.S. Territories to the extent they are known to occur (e.g., coal mining does not occur in U.S. Territories). For some sources there is a lack of detailed information on U.S. Territories including some non-CO_2 emissions from combustion. As part of continuous improvement efforts, EPA reviews this on an ongoing basis to ensure emission sources are included across all geographic areas including U.S. Territories if they are occurring. See Annex 5 for more information on EPA's assessment of the sources not included in this Inventory.

Each year, some emission and sink estimates in the Inventory are recalculated and revised with improved methods and/or data. In general, recalculations are made to the U.S. greenhouse gas emission estimates either to incorporate new methodologies or, most commonly, to update recent historical data. These improvements are implemented consistently across the previous Inventory's time series (i.e., 1990 to 2018) to ensure that the trend is accurate. Key updates in this year's Inventory include updates to CO_2 emissions from Fossil Fuel Combustion (e.g., updates to CO_2 emission factors for gasoline and diesel fuels, updates to CH_4 and N_2O emission factors for newer non-road gasoline and diesel vehicles and changes to activity and carbon content coefficients), updates to carbon emissions from non-energy uses of fossil fuels (e.g., heat contents for hydrocarbon gas liquids) and updates to fugitive emission sources (e.g., CH_4 and CO_2 emissions from natural gas systems distribution and production). The combined impact of these recalculations averaged -10.5 MMT CO_2 Eq. (-0.2 percent) per year across the time series. For more information on specific methodological updates, please see the Recalculations section for each category in this chapter.

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

In following the United Nations Framework Convention on Climate Change (UNFCCC) requirement under Article 4.1 to develop and submit national greenhouse gas emission inventories, the emissions and removals presented in this report and this chapter are organized by source and sink categories and calculated using internationally-accepted methods provided by the Intergovernmental Panel on Climate Change (IPCC) in the *2006 IPCC Guidelines for National Greenhouse Gas Inventories (2006 IPCC Guidelines)*. Additionally, the calculated emissions and removals in a given year for the United States are presented in a common format in line with the UNFCCC reporting guidelines for the reporting of inventories under this international agreement. The use of consistent methods to calculate emissions and removals by all nations providing their inventories to the UNFCCC ensures that these reports are comparable. The presentation of emissions and removals provided in the Energy chapter do not preclude alternative examinations, but rather, this chapter presents emissions and removals in a common format consistent with how countries are to report Inventories under the UNFCCC. The report itself, and this chapter, follows this standardized format, and provides an explanation of the application of methods used to calculate emissions and removals from energy-related activities.

Energy Data from EPA's Greenhouse Gas Reporting Program

EPA's Greenhouse Gas Reporting Program (GHGRP)[4] dataset and the data presented in this Inventory are complementary. The Inventory was used to guide the development of the GHGRP, particularly in terms of scope and coverage of both sources and gases. The GHGRP dataset continues to be an important resource for the Inventory, providing not only annual emissions information, but also other annual information, such as activity data and emission factors that can improve and refine national emission estimates and trends over time. GHGRP data also allow EPA to disaggregate national inventory estimates in new ways that can highlight differences across regions and sub-categories of emissions, along with enhancing application of QA/QC procedures and assessment of uncertainties.

EPA uses annual GHGRP data in a number of Energy sector categories to improve the national estimates presented in this Inventory consistent with IPCC guidelines (see Box 3-3 of this chapter, and sections 3.4 Coal Mining, 3.6 Petroleum Systems, and 3.6 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 CO_2 Emissions from Fossil Fuel Combustion, for use in reporting emissions in Common Reporting Format (CRF) tables (See Box 3-3). The industrial end-use sector activity data collected for the Inventory (EIA 2020) 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 greenhouse gases CO_2, CH_4, and N_2O. Given that CO_2 is the primary gas emitted from fossil fuel combustion and represents the largest share of U.S. total emissions, CO_2 emissions from fossil fuel combustion are discussed at the beginning of this section. An overview of CH_4 and N_2O emissions from the combustion of fuels in stationary sources is then presented, followed by fossil fuel combustion emissions for all three gases by end-use sector: electric power, industrial, residential, commercial, U.S. Territories, and transportation.

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

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

Methodologies for estimating CO_2 emissions from fossil fuel combustion differ from the estimation of CH_4 and N_2O emissions from stationary combustion and mobile combustion. Thus, three separate descriptions of methodologies, uncertainties, recalculations, and planned improvements are provided at the end of this section. Total CO_2, CH_4, and N_2O emissions from fossil fuel combustion are presented in Table 3-3 and Table 3-4.

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

Gas	1990	2005	2015	2016	2017	2018	2019
CO_2	4,731.5	5,753.5	5,008.3	4,911.5	4,854.5	4,991.4	4,856.7
CH_4	15.0	11.8	11.1	10.4	10.1	11.0	11.0
N_2O	69.8	75.9	52.3	50.8	48.3	47.1	42.9
Total	**4,816.3**	**5,841.2**	**5,071.6**	**4,972.8**	**4,912.9**	**5,049.5**	**4,910.6**

Note: Totals may not sum due to independent rounding.

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

Gas	1990	2005	2015	2016	2017	2018	2019
CO_2	4,731,466	5,753,507	5,008,270	4,911,532	4,854,480	4,991,420	4,856,702
CH_4	600	471	444	417	406	440	441
N_2O	234	255	175	171	162	158	144

CO_2 from Fossil Fuel Combustion

Carbon dioxide is the primary gas emitted from fossil fuel combustion and represents the largest share of U.S. total greenhouse gas emissions. Carbon dioxide emissions from fossil fuel combustion are presented in Table 3-5. In 2019, CO_2 emissions from fossil fuel combustion decreased by 2.7 percent relative to the previous year (as shown in Table 3-6). The decrease in CO_2 emissions from fossil fuel consumption was a result of a 1 percent decrease in total energy use and reflects a continued shift from coal to less carbon intensive natural gas and renewables in the electric power sector. Carbon dioxide emissions from natural gas consumption increased by 53.4 MMT CO_2 Eq. in 2019, a 3.4 percent increase from 2018, while CO_2 emissions from coal consumption decreased by 185.3 MMT CO_2 Eq., a 15.2 percent decrease. The increase in natural gas consumption and emissions in 2019 is observed across all sectors and is primarily driven by a shift away from coal consumption in the Electric Power sector. In 2019, CO_2 emissions from fossil fuel combustion were 4,856.7 MMT CO_2 Eq., or 2.6 percent above emissions in 1990 (see Table 3-5).[6]

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

Fuel/Sector	1990	2005	2015	2016	2017	2018	2019
Coal	**1,719.8**	**2,113.7**	**1,428.5**	**1,310.7**	**1,270.2**	**1,211.6**	**1,027.1**
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	117.8	70.0	63.2	58.7	54.4	49.5
Transportation	NO	NO	NO	NO	NO	NO	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**	**1,454.9**	**1,461.3**	**1,434.6**	**1,591.2**	**1,644.6**
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	459.1	463.9	469.5	494.0	503.3
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

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

U.S. Territories	NO	1.3	3.0	3.4	2.5	2.5	2.5
Petroleum	**2,011.2**	**2,472.3**	**2,124.5**	**2,139.2**	**2,149.2**	**2,188.2**	**2,184.6**
Residential	97.8	95.9	64.6	54.4	51.9	64.2	61.5
Commercial	74.3	54.9	66.2	58.7	56.8	51.4	55.3
Industrial	287.2	346.4	268.2	265.4	261.9	265.2	269.7
Transportation	1,433.1	1,825.6	1,679.8	1,719.8	1,740.2	1,765.6	1,762.5
Electric Power	97.5	98.0	23.7	21.5	18.9	22.2	16.2
U.S. Territories	21.2	51.6	22.1	19.4	19.5	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**	**5,753.5**	**5,008.3**	**4,911.5**	**4,854.5**	**4,991.4**	**4,856.7**

Note: Totals may not sum due to independent rounding.

NO (Not Occurring)

[a] Although not technically a fossil fuel, geothermal energy-related CO_2 emissions are included for reporting purposes. The source of CO_2 is non-condensable gases in subterranean heated water.

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

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

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

[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.

Table 3-6: Annual Change in CO_2 Emissions and Total 2019 CO_2 Emissions from Fossil Fuel Combustion for Selected Fuels and Sectors (MMT CO_2 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	40.0	2.4%	20.4	1.2%	25.5	1.5%	-3.2	-0.2%	1,762.5
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	4.8	1.0%	5.6	1.2%	24.5	5.2%	9.3	1.9%	503.3
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]**	**40.6**	**2.4%**	**22.6**	**1.3%**	**34.1**	**1.9%**	**0.6**	**+%**	**1,817.2**
Residential	**All Fuels[a]**	**-24.5**	**-7.7%**	**0.6**	**0.2%**	**44.7**	**15.2%**	**-1.3**	**-0.4%**	**336.8**
Commercial	**All Fuels[a]**	**-13.0**	**-5.3%**	**0.4**	**0.2%**	**13.7**	**5.9%**	**4.0**	**1.6%**	**249.7**
Industrial	**All Fuels[a]**	**-4.8**	**-0.6%**	**-2.4**	**-0.3%**	**23.5**	**3.0%**	**8.9**	**1.1%**	**822.5**
All Sectors[a]	**All Fuels[a]**	**-96.7**	**-1.9%**	**-57.1**	**-1.2%**	**136.9**	**2.8%**	**-134.7**	**-2.7%**	**4,856.7**

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

+ Does not exceed 0.05 percent.

As shown in Table 3-6, recent trends in CO_2 emissions from fossil fuel combustion show a 1.9 percent decrease from 2015 to 2016, a 1.2 percent decrease from 2016 to 2017, a 2.8 percent increase from 2017 to 2018, and a 2.7 percent decrease from 2018 to 2019. These changes contributed to an overall 3.0 percent decrease in CO_2 emissions from fossil fuel combustion from 2015 to 2019.

Trends in CO_2 emissions from fossil fuel combustion over the past five years are largely driven by the electric power sector, which until recently has accounted for the largest portion of these emissions. The types of fuels consumed to produce electricity have changed in recent years. Electric power sector consumption of natural gas primarily increased due to increased production capacity as natural gas-fired plants replaced coal-fired plants and increased electricity demand related to heating and cooling needs (EIA 2018; EIA 2020f). Total electric power generation increased by 0.01 percent from 2015 to 2016, decreased by 1.0 percent from 2016 to 2017, increased by 3.6 percent from 2017 to 2018 and decreased by 1.4 percent from 2018 to 2019. Carbon dioxide emissions decreased from 2018 to 2019 by 8.4 percent due to increasing electric power generation from natural gas and decreasing generation from petroleum and coal. Carbon dioxide emissions from coal consumption for electric power generation decreased by 28.0 percent since 2015, which can be largely attributed to a shift to the use of less-CO_2-intensive natural gas to generate electricity and a rapid increase in renewable energy capacity additions in the electric power sector in recent years.

The trends in CO_2 emissions from fossil fuel combustion over the past five years also follow changes in heating degree days (see Box 3-2). Emissions from natural gas consumption in the residential and commercial sectors increased by 8.2 percent and 9.0 percent from 2015 to 2019, respectively. This trend can be largely attributed to a 5.3 percent increase in heating degree days from 2015 to 2019, which led to an increased demand for heating fuel and electricity for heat in these sectors. Industrial consumption of natural gas is dependent on market effects of supply and demand in addition to weather-related heating needs.

Petroleum use in the transportation sector is another major driver of emissions, representing the largest source of CO_2 emissions from fossil fuel combustion in 2019. Emissions from petroleum consumption for transportation have increased by 4.9 percent since 2015 and are primarily attributed to a 5.4 percent increase in vehicle miles traveled (VMT) over the same time period. Beginning with 2017, the transportation sector is the largest source of national CO_2 emissions – whereas in prior years, electric power was the largest source sector.

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

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

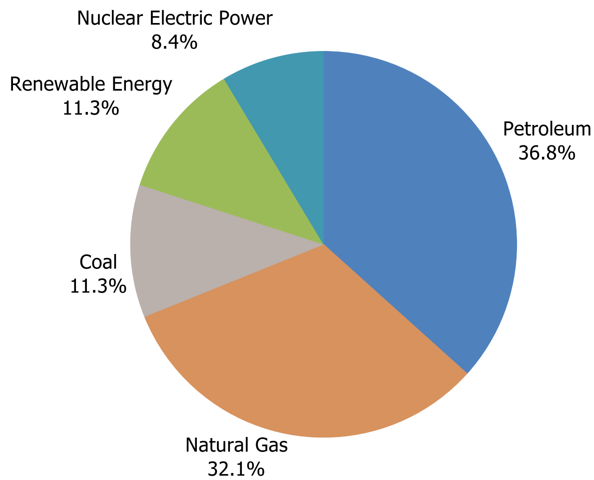
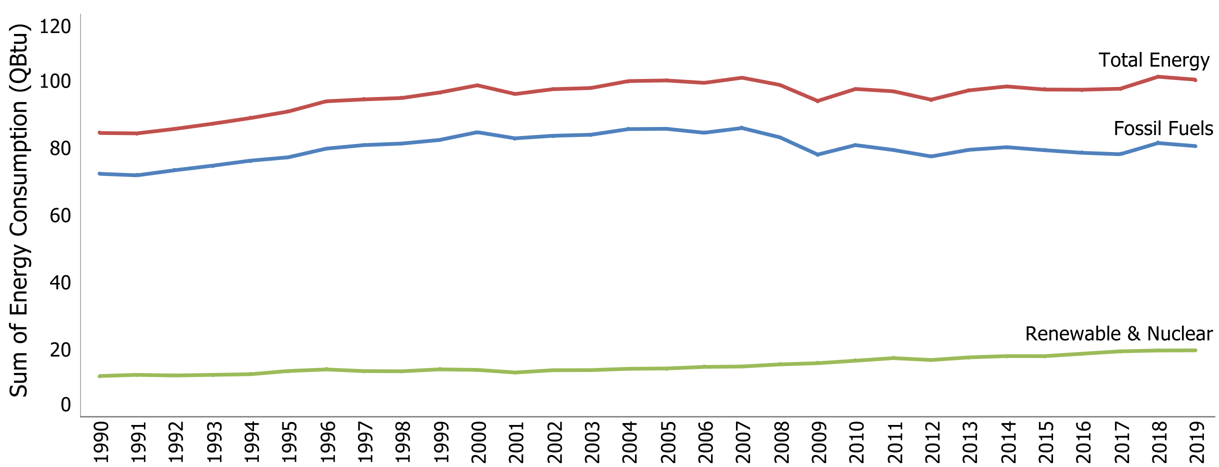
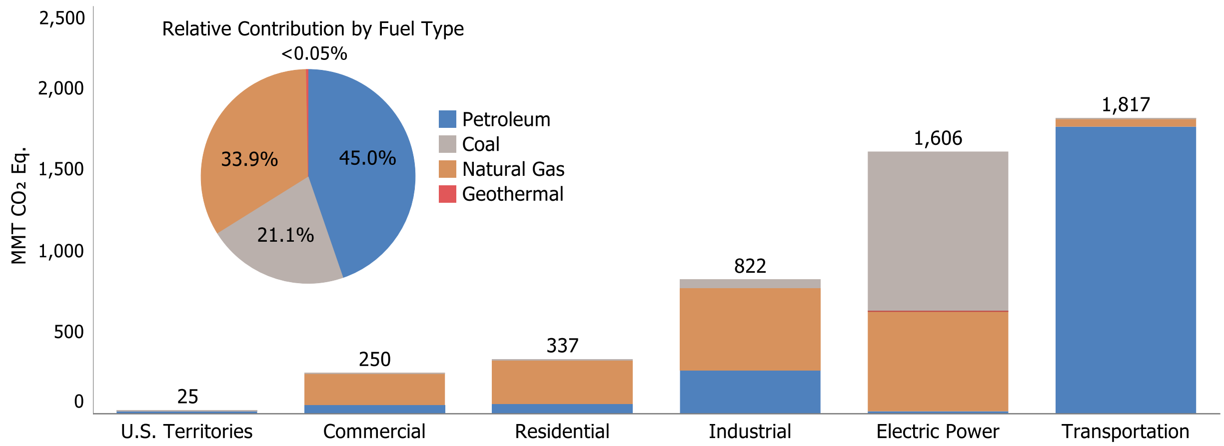


Figure 3-5: Annual U.S. Energy Use



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

Figure 3-6: 2019 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type



Fossil fuels are generally combusted for the purpose of producing energy for useful heat and work. During the combustion process, the C stored in the fuels is oxidized and emitted as CO_2 and smaller amounts of other gases, including CH_4, carbon monoxide (CO), and non-methane volatile organic compounds (NMVOCs).[9] These other C-containing non-CO_2 gases are emitted as a byproduct of incomplete fuel combustion, but are, for the most part, eventually oxidized to CO_2 in the atmosphere. Therefore, as per IPCC guidelines it is assumed all of the C in fossil fuels used to produce energy is eventually converted to atmospheric CO_2.

Box 3-2: Weather and Non-Fossil Energy Effects on CO_2 Emissions from Fossil Fuel Combustion Trends

The United States in 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 0.4 and 1.6 percent, respectively relative to 2018.

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

[10] Degree days are relative measurements of outdoor air temperature. Heating degree days are deviations of the mean daily temperature below 65 degrees Fahrenheit, while cooling degree days are deviations of the mean daily temperature above 65 degrees Fahrenheit. Heating degree days have a considerably greater effect on energy demand and related emissions than do cooling degree days. Excludes Alaska and Hawaii. Normals are based on data from 1981 through 2010. The variation in these normals during this time period was ±15 percent and ±23 percent for heating and cooling degree days, respectively (99 percent confidence interval).

Figure 3-7: Annual Deviations from Normal Heating Degree Days for the United States (1950–2019, Index Normal = 100)

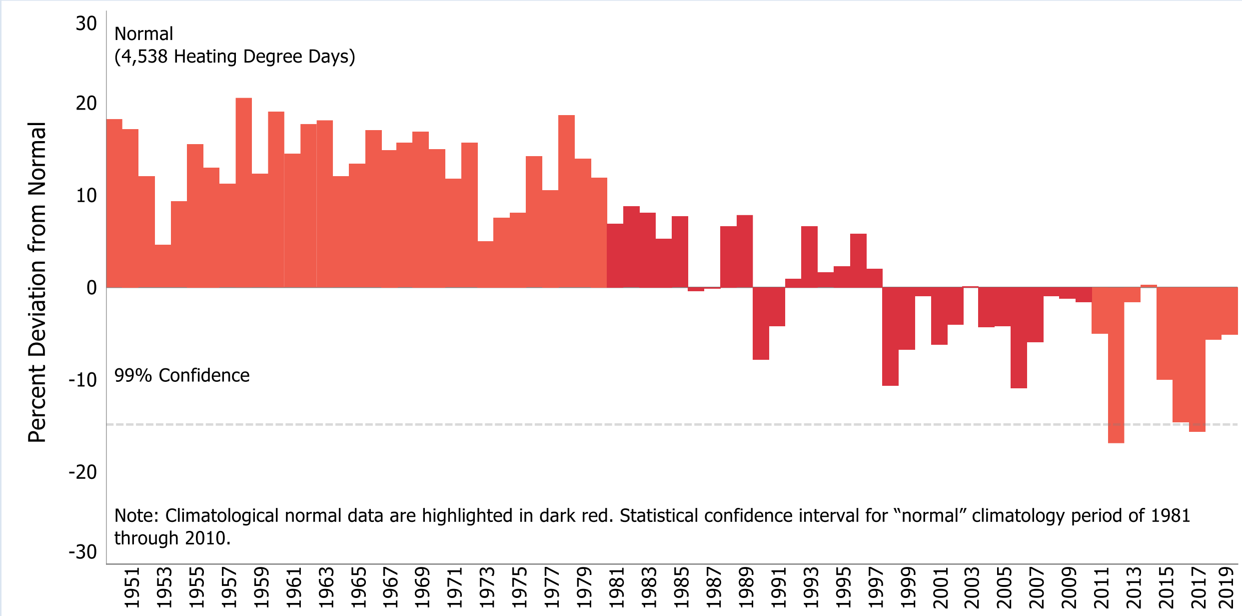
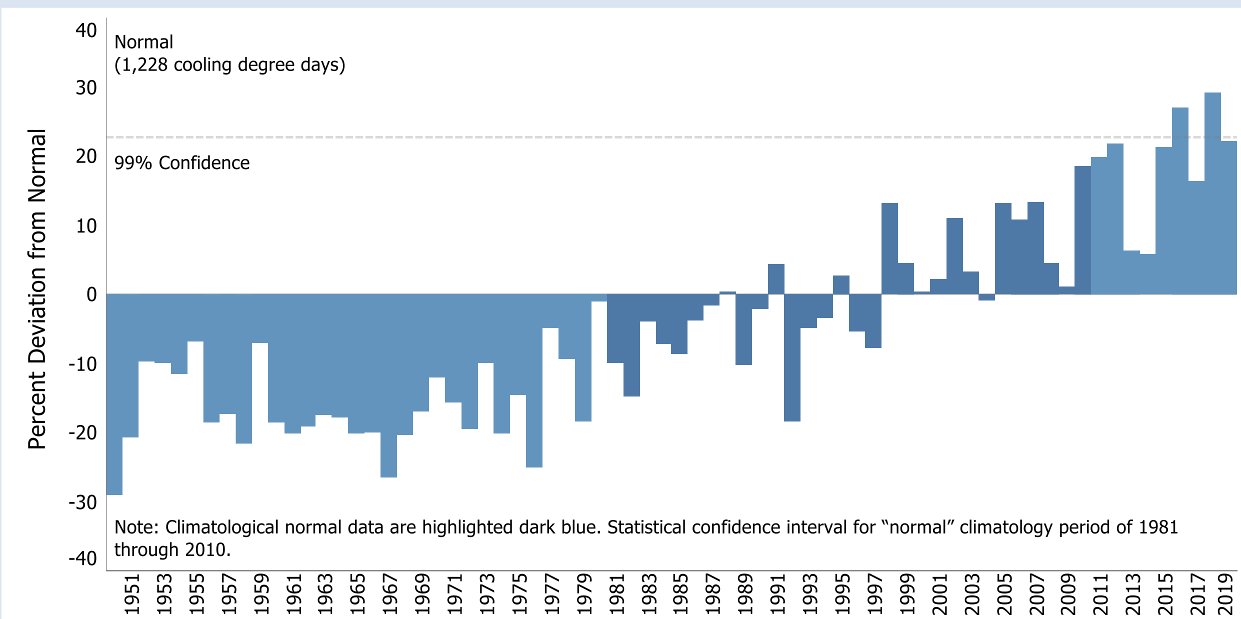


Figure 3-8: Annual Deviations from Normal Cooling Degree Days for the United States (1950–2019, Index Normal = 100)



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

Stationary Combustion

The direct combustion of fuels by stationary sources in the electric power, industrial, commercial, and residential sectors represent the greatest share of U.S. greenhouse gas emissions. Table 3-7 presents CO_2 emissions from fossil fuel combustion by stationary sources. The CO_2 emitted is closely linked to the type of fuel being combusted in each sector (see Methodology section of CO_2 from Fossil Fuel Combustion). In addition to the CO_2 emitted from fossil fuel combustion, CH_4 and N_2O are emitted as well. Table 3-8 and Table 3-9 present CH_4 and N_2O emissions from the combustion of fuels in stationary sources. The CH_4 and N_2O emissions are estimated by applying a "bottom-up" methodology that utilizes facility-specific technology and fuel use data reported to EPA's Acid Rain Program (EPA 2020a) (see Methodology section for CH_4 and N_2O from Stationary Combustion).

Table 3-7: CO_2 Emissions from Stationary Fossil Fuel Combustion (MMT CO_2 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**	**852.9**	**797.3**	**792.5**	**790.1**	**813.6**	**822.5**
Coal	157.8	117.8	70.0	63.2	58.7	54.4	49.5
Natural Gas	408.8	388.6	459.1	463.9	469.5	494.0	503.3
Fuel Oil	287.2	346.4	268.2	265.4	261.9	265.2	269.7
Commercial	**228.3**	**227.1**	**244.6**	**231.6**	**232.0**	**245.7**	**249.7**
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	54.9	66.2	58.7	56.8	51.4	55.3
Residential	**338.6**	**358.9**	**317.3**	**292.8**	**293.4**	**338.1**	**336.8**
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	95.9	64.6	54.4	51.9	64.2	61.5
U.S. Territories	**21.7**	**55.9**	**29.2**	**26.0**	**24.6**	**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	51.6	22.1	19.4	19.5	19.5	19.5
Total	**3,262.4**	**3,894.9**	**3,289.0**	**3,151.7**	**3,072.0**	**3,174.9**	**3,039.5**

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

[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).

Table 3-8: CH_4 Emissions from Stationary Combustion (MMT CO_2 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**	**1.5**	**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	0.2	0.2	0.2
Natural gas	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Wood	1.0	1.0	1.1	1.0	1.0	1.0	1.0
Commercial	**1.1**	**1.1**	**1.2**	**1.2**	**1.2**	**1.2**	**1.2**
Coal	+	+	+	+	+	+	+
Fuel Oil	0.3	0.2	0.2	0.2	0.2	0.2	0.2
Natural gas	0.3	0.4	0.4	0.4	0.4	0.4	0.4
Wood	0.5	0.5	0.6	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	0.0	0.0	0.0	0.0	0.0
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	NO	NO	NO	NO	NO	NO
Total	**8.6**	**7.8**	**8.5**	**7.9**	**7.6**	**8.5**	**8.7**

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

Table 3-9: N_2O Emissions from Stationary Combustion (MMT CO_2 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	0.4	0.4	0.4
Natural Gas	0.2	0.2	0.2	0.2	0.3	0.3	0.3
Wood	1.6	1.6	1.7	1.7	1.6	1.6	1.6
Commercial	**0.4**	**0.3**	**0.4**	**0.3**	**0.3**	**0.3**	**0.3**
Coal	0.1	+	+	+	+	+	+
Fuel Oil	0.2	0.1	0.2	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**	**0.7**	**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**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Coal	+	+	+	+	+	+	+
Fuel Oil	0.1	0.1	0.1	+	+	+	+
Natural Gas	NO	+	+	+	+	+	+
Wood	NO	NO	NO	NO	NO	NO	NO
Total	**25.1**	**34.4**	**30.5**	**30.0**	**28.4**	**28.2**	**24.9**

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

Fossil Fuel Combustion Emissions by Sector

Table 3-10 provides an overview of the CO_2, CH_4, and N_2O emissions from fossil fuel combustion by sector, including transportation, electric power, industrial, residential, commercial, and U.S. territories.

Table 3-10: CO_2, CH_4, and N_2O Emissions from Fossil Fuel Combustion by Sector (MMT CO_2 Eq.)

End-Use Sector	1990	2005	2015	2016	2017	2018	2019
Transportation	**1,520.2**	**1,904.2**	**1,743.6**	**1,783.2**	**1,804.8**	**1,837.8**	**1,837.5**
CO_2	1,469.1	1,858.6	1,719.2	1,759.9	1,782.4	1,816.6	1,817.2
CH_4	6.4	4.0	2.6	2.5	2.5	2.4	2.4
N_2O	44.7	41.6	21.7	20.8	19.8	18.8	18.0
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_2O	20.5	30.1	26.5	26.2	24.8	24.4	21.1
Industrial	**858.7**	**857.6**	**801.5**	**796.7**	**794.2**	**817.6**	**826.5**
CO_2	853.8	852.9	797.3	792.5	790.1	813.6	822.5
CH_4	1.8	1.7	1.6	1.6	1.5	1.5	1.5
N_2O	3.1	2.9	2.6	2.6	2.5	2.5	2.5
Residential	**344.9**	**363.8**	**322.6**	**297.4**	**297.9**	**343.5**	**342.3**
CO_2	338.6	358.9	317.3	292.8	293.4	338.1	336.8
CH_4	5.2	4.1	4.5	3.9	3.8	4.5	4.6
N_2O	1.0	0.9	0.9	0.8	0.7	0.9	0.9
Commercial	**229.8**	**228.6**	**246.2**	**233.1**	**233.5**	**247.3**	**251.3**
CO_2	228.3	227.1	244.6	231.6	232.0	245.7	249.7
CH_4	1.1	1.1	1.2	1.2	1.2	1.2	1.2
N_2O	0.4	0.3	0.4	0.3	0.3	0.3	0.3
U.S. Territories[a]	**21.8**	**56.1**	**29.3**	**26.1**	**24.6**	**24.7**	**24.7**
Total	**4,816.3**	**5,841.2**	**5,071.6**	**4,972.8**	**4,912.9**	**5,049.5**	**4,910.6**

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.

Other than greenhouse gases CO_2, CH_4, and N_2O, gases emitted from stationary combustion include the greenhouse gas precursors nitrogen oxides (NO_x), CO, and NMVOCs.[12] Methane and N_2O emissions from stationary combustion sources depend upon fuel characteristics, size and vintage of combustion device, along with combustion technology, pollution control equipment, ambient environmental conditions, and operation and maintenance practices. Nitrous oxide emissions from stationary combustion are closely related to air-fuel mixes

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

and combustion temperatures, as well as the characteristics of any pollution control equipment that is employed. Methane emissions from stationary combustion are primarily a function of the CH_4 content of the fuel and combustion efficiency.

Mobile combustion also produces emissions of CH_4, N_2O, and greenhouse gas precursors including NO_x, CO, and NMVOCs. As with stationary combustion, N_2O and NO_x emissions from mobile combustion are closely related to fuel characteristics, air-fuel mixes, combustion temperatures, and the use of pollution control equipment. Nitrous oxide from mobile sources, in particular, can be formed by the catalytic processes used to control NO_x, CO, and hydrocarbon emissions. Carbon monoxide emissions from mobile combustion are significantly affected by combustion efficiency and the presence of post-combustion emission controls. Carbon monoxide emissions are highest when air-fuel mixtures have less oxygen than required for complete combustion. These emissions occur especially in vehicle idle, low speed, and cold start conditions. Methane and NMVOC emissions from motor vehicles are a function of the CH_4 content of the motor fuel, the amount of hydrocarbons passing uncombusted through the engine, and any post-combustion control of hydrocarbon emissions (such as catalytic converters).

An alternative method of presenting combustion emissions is to allocate emissions associated with electric power to the sectors in which it is used. Four end-use sectors are defined: transportation, industrial, residential, and commercial. In Table 3-11 below, electric power emissions have been distributed to each end-use sector based upon the sector's share of national electricity use, with the exception of CH_4 and N_2O from transportation electricity use.[13] Emissions from U.S. Territories are also calculated separately due to a lack of end-use-specific consumption data.[14] This method assumes that emissions from combustion sources are distributed across the four end-use sectors based on the ratio of electricity use in that sector. The results of this alternative method are presented in Table 3-11.

Table 3-11: CO_2, CH_4, and N_2O Emissions from Fossil Fuel Combustion by End-Use Sector (MMT CO_2 Eq.)

End-Use Sector	1990		2005		2015	2016	2017	2018	2019
Transportation	**1,523.3**		**1,908.9**		**1,747.9**	**1,787.4**	**1,809.1**	**1,842.5**	**1,842.3**
CO_2	1,472.2		1,863.4		1,723.5	1,764.1	1,786.8	1,821.2	1,821.9
CH_4	6.4		4.0		2.6	2.5	2.5	2.4	2.4
N_2O	44.7		41.6		21.7	20.8	19.8	18.8	18.0
Industrial	**1,553.0**		**1,603.4**		**1,359.1**	**1,322.1**	**1,306.1**	**1,326.3**	**1,298.3**
CO_2	1,540.2		1,589.2		1,346.8	1,310.1	1,294.5	1,314.9	1,287.8
CH_4	2.0		2.0		1.9	1.9	1.9	1.9	1.9
N_2O	10.8		12.2		10.3	10.1	9.8	9.5	8.6
Residential	**944.4**		**1,230.9**		**1,016.4**	**960.8**	**924.2**	**995.0**	**933.9**
CO_2	931.3		1,214.9		1,001.1	946.2	910.5	980.2	920.3
CH_4	5.4		4.4		4.9	4.3	4.2	5.0	5.1
N_2O	7.7		11.6		10.4	10.3	9.6	9.9	8.6
Commercial	**773.7**		**1,041.9**		**918.9**	**876.3**	**848.8**	**861.0**	**811.4**
CO_2	766.0		1,030.1		907.6	865.2	838.2	850.6	802.1
CH_4	1.2		1.4		1.6	1.6	1.6	1.6	1.7
N_2O	6.5		10.4		9.6	9.5	9.0	8.8	7.6
U.S. Territories[a]	**21.8**		**56.1**		**29.3**	**26.1**	**24.6**	**24.7**	**24.7**
Total	**4,816.3**		**5,841.2**		**5,071.6**	**4,972.8**	**4,912.9**	**5,049.5**	**4,910.6**

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.

[13] Separate calculations are performed for transportation-related CH_4 and N_2O. 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.

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

Electric Power Sector

The process of generating electricity is the largest stationary source of CO_2 emissions in the United States, representing 30.6 percent of total CO_2 emissions from all CO_2 emissions sources across the United States. Methane and N_2O accounted for a small portion of total greenhouse gas emissions from electric power, representing 0.1 percent and 1.3 percent, respectively. Electric power also accounted for 33.1 percent of CO_2 emissions from fossil fuel combustion in 2019. Methane and N_2O from electric power represented 11.4 and 49.3 percent of total CH_4 and N_2O emissions from fossil fuel combustion in 2019, respectively.

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

Total greenhouse gas emissions from the electric power sector have decreased by 11.5 percent since 1990. From 1990 to 2007, electric power sector emissions increased by 32 percent, driven by a significant increase in electricity demand (37 percent) while the carbon intensity of electricity generated showed a minor increase (0.3 percent). From 2008 to 2019, as electricity demand increased by only 2 percent, electric power sector emissions decreased by 13 percent, driven by a significant drop (26 percent) in the carbon intensity of electricity generated. Overall, the carbon intensity of the electric power sector, in terms of CO_2 Eq. per QBtu, decreased by 16 percent from 1990 to 2019 with additional trends detailed in Box 3-4. This decoupling of electric power generation and the resulting CO_2 emissions is shown in Figure 3-9. This recent decarbonization of the electric power sector is a result of several key drivers.

Coal-fired electric generation (in kilowatt-hours [kWh]) decreased from 54 percent of generation in 1990 to 24 percent in 2019.[16] This corresponded with an increase in natural gas generation and renewable energy generation, largely from wind and solar energy. Natural gas generation (in kWh) represented 11 percent of electric power generation in 1990 and increased over the 30-year period to represent 37 percent of electric power sector generation in 2019 (see Table 3-12). Natural gas has a much lower carbon content than coal and is generated in power plants that are generally more efficient in terms of kWh produced per Btu of fuel combusted, which has led to lower emissions as natural gas replaces coal-powered electricity generation. Natural gas and coal used in the U.S. in 2019 had an average carbon content of 14.43 MMT C/QBtu and 26.08 MMT C/QBtu respectively.

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%

[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).

Net Electricity Generation (Billion kWh)[b]	*2,905*		*3,902*		*3,917*	*3,917*	*3,877*	*4,017*	*3,962*

+ Does not exceed 0.05 percent.

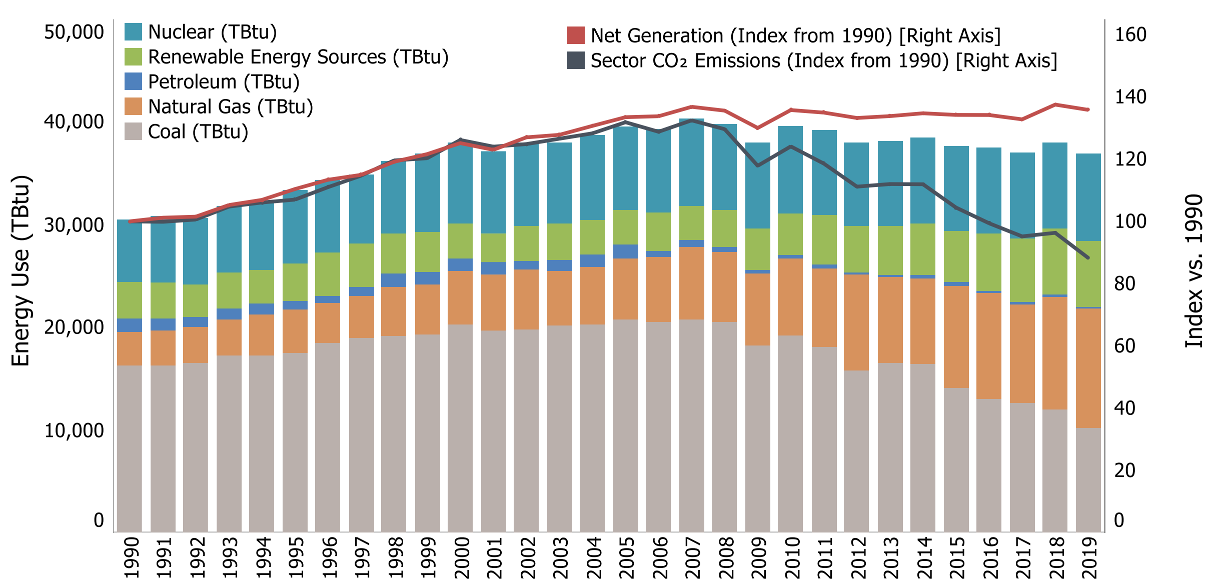
[a] Other gases include blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.

[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. Does not include electricity generation from purchased steam as the fuel used to generate the steam cannot be determined.

In 2019, CO_2 emissions from the electric power sector decreased by 8.4 percent relative to 2018. This decrease in CO_2 emissions was primarily driven by a decrease in coal and petroleum consumed to produce electricity in the electric power sector as well as a decrease in electricity demand (1.2 percent reduction in retail sales). Consumption of coal for electric power decreased by 15.5 percent while consumption of natural gas increased 6.7 percent from 2018 to 2019. There has also been a rapid increase in renewable energy electricity generation in the electric power sector in recent years. Electricity generation from renewable sources increased by 3 percent from 2018 to 2019 (see Table 3-12). The decrease in coal-powered electricity generation and increase in natural gas and renewable energy electricity generation contributed to a decoupling of emissions trends from electric power generation trends over the recent time series (see Figure 3-9).

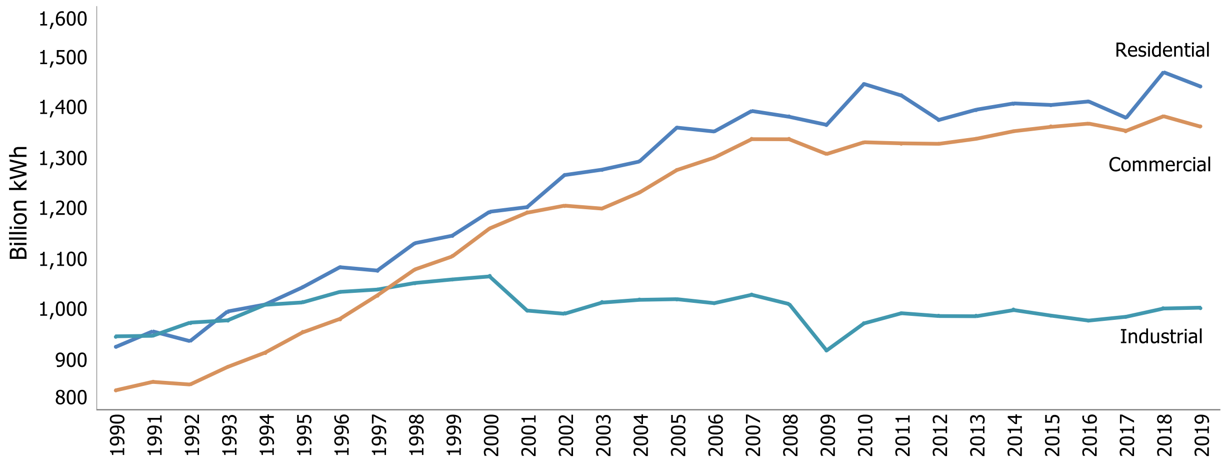
Decreases in natural gas prices and the associated increase in natural gas generation, particularly between 2005 and 2019, was one of the main drivers of the recent fuel switching and decrease in electric power sector carbon intensity. During this time period, the cost of natural gas (in $/MMBtu) decreased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

Figure 3-9: Fuels Used in Electric Power Generation and Total Electric Power Sector CO_2 Emissions



Electricity was used primarily in the residential, commercial, and industrial end-use sectors for lighting, heating, electric motors, appliances, electronics, and air conditioning (see Figure 3-10). Note that transportation is an end-use sector as well but is not shown in Figure 3-10 due to the sector's relatively low percentage of electricity use. Table 3-13 provides a break-out of CO_2 emissions from electricity use in the transportation end-use sector.

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



In 2019, electricity sales to the residential and commercial end-use sectors, as presented in Figure 3-10, decreased by 2.0 percent and 1.5 percent relative to 2018, respectively. Electricity sales to the industrial sector in 2019 increased approximately 0.2 percent relative to 2018. The sections below describe end-use sector energy use in more detail. Overall, in 2019, the amount of electricity retail sales (in kWh) decreased by 1.2 percent relative to 2018.

Industrial Sector

Industrial sector CO_2, CH_4, and N_2O emissions accounted for 17, 14, and 6 percent of CO_2, CH_4, and N_2O emissions from fossil fuel combustion, respectively in 2019. Carbon dioxide, CH_4, and N_2O emissions resulted from the direct consumption of fossil fuels for steam and process heat production.

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

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

From 2018 to 2019, total industrial production and manufacturing output increased by 0.2 percent (FRB 2019). Over this period, output increased across production indices for Food, and Nonmetallic Mineral Products, and decreased slightly for Paper, Petroleum Refineries, Chemicals, and Primary Metals (see Figure 3-11). From 2018 to 2019, total energy use in the industrial sector increased by 1.5 percent. Due to the relative increases and decreases of individual indices there was an increase in natural gas and a decrease in electricity used by the sector (see Figure 3-12). In 2019, CO_2, CH_4, and N_2O emissions from fossil fuel combustion and electricity use within the industrial end-use sector totaled 1,298.3 MMT CO_2 Eq., a 2.1 percent decrease from 2018 emissions.

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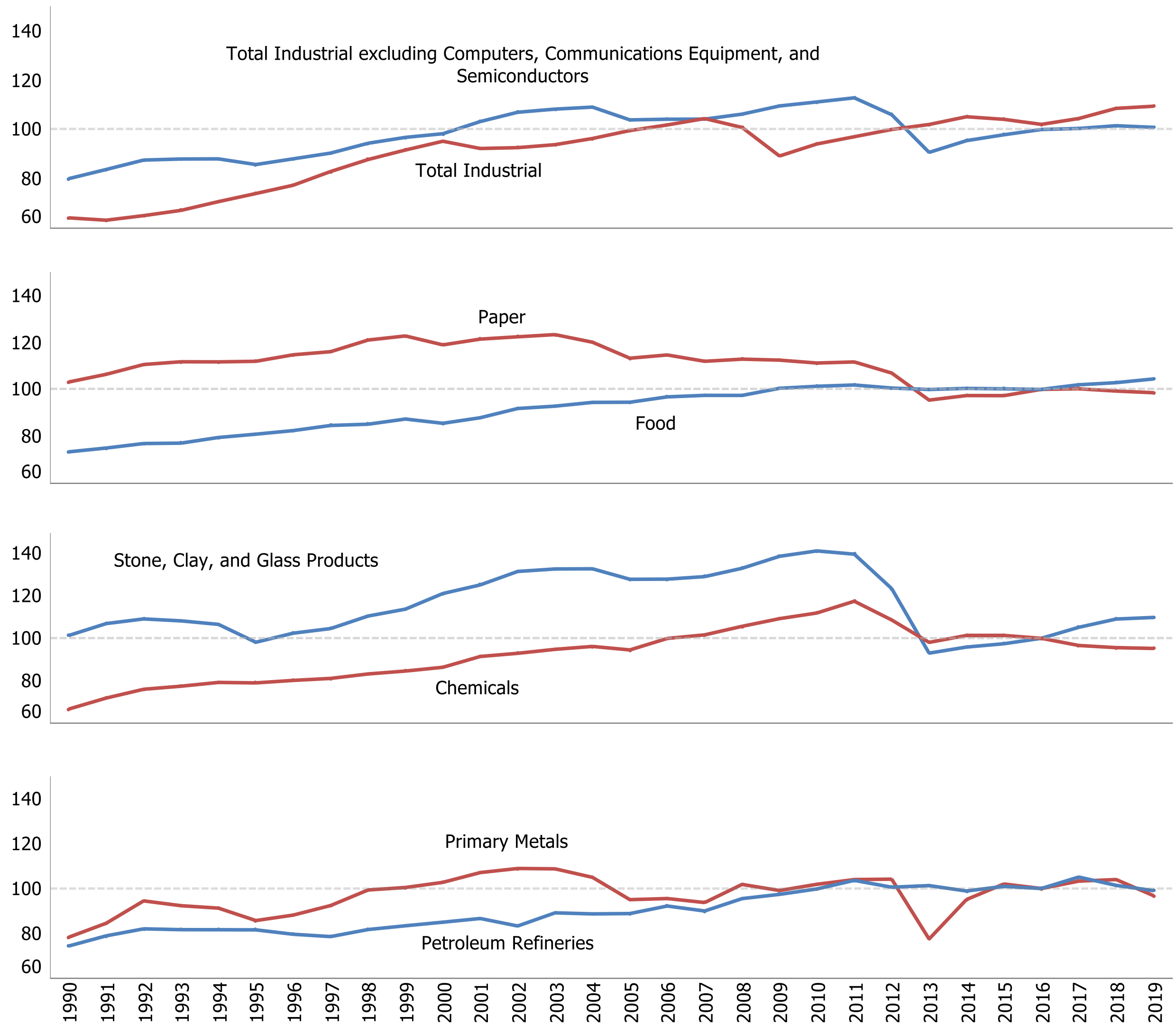
[17] Some commercial customers are large enough to obtain an industrial price for natural gas and/or electricity and are consequently grouped with the industrial end-use sector in U.S. energy statistics. These misclassifications of large commercial customers likely cause the industrial end-use sector to appear to be more sensitive to weather conditions.

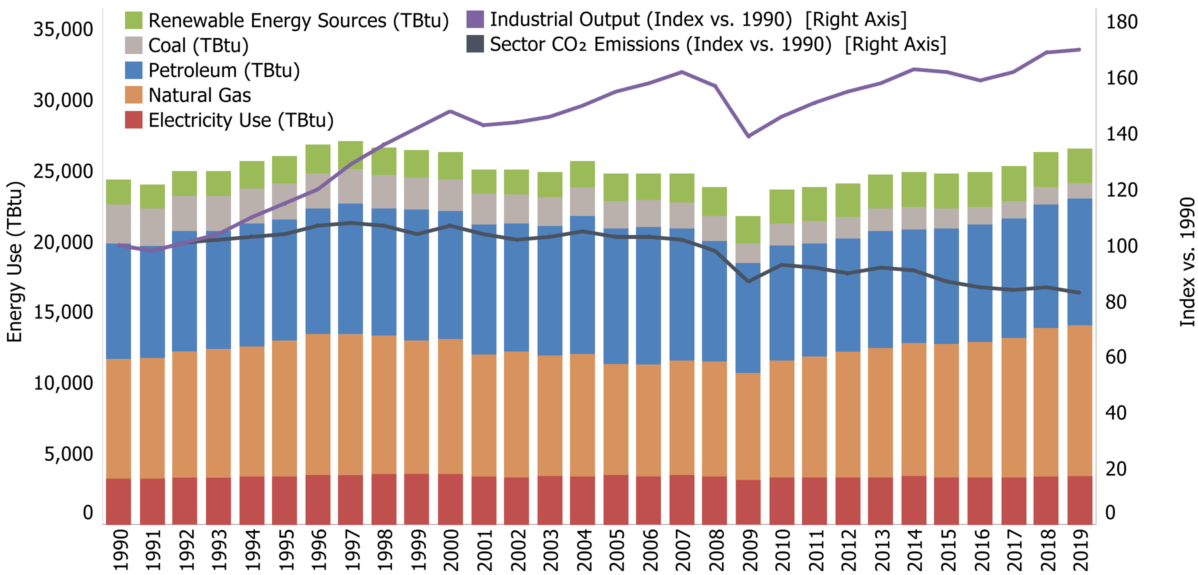
Through EPA's Greenhouse Gas Reporting Program (GHGRP), specific industrial sector trends can be discerned from the overall total EIA industrial fuel consumption data used for these calculations. For example, from 2018 to 2019, the underlying EIA data showed decreased consumption of coal, and increase of natural gas in the industrial sector. The GHGRP data highlights that several industries contributed to these trends, including chemical manufacturing; pulp, paper and print; food processing, beverages and tobacco; minerals manufacturing; and agriculture-forest-fisheries.[18]

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



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

Figure 3-12: Fuels and Electricity Used in Industrial Sector, Industrial Output, and Total Sector CO_2 Emissions (Including Electricity)



Despite the growth in industrial output (70 percent) and the overall U.S. economy (104 percent) from 1990 to 2019, direct CO_2 emissions from fossil fuel combustion in the industrial sector decreased by 3.7 percent over the same time series (see Figure 3-12). A number of factors are assumed to result in decoupling of growth in industrial output from industrial greenhouse gas emissions, for example: (1) more rapid growth in output from less energy-intensive industries relative to traditional manufacturing industries, and (2) energy-intensive industries such as steel are employing new methods, such as electric arc furnaces, that are less carbon intensive than the older methods.

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

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

For GHGRP 2010 through 2019 reporting years, facility-level fossil fuel combustion emissions reported through EPA's GHGRP were categorized and distributed to specific industry types by utilizing facility-reported NAICS codes (as published by the U.S. Census Bureau). As noted previously in this report, the definitions and provisions for reporting fuel types in EPA's GHGRP include some differences from the Inventory's use of EIA national fuel statistics to meet the UNFCCC reporting guidelines. The IPCC has provided guidance on aligning facility-level reported fuels and fuel types published in national energy statistics, which guided this exercise. [19]

As with previous Inventory reports, the current effort represents an attempt to align, reconcile, and coordinate the facility-level reporting of fossil fuel combustion emissions under EPA's GHGRP with the national-level approach presented in this report. Consistent with recommendations for reporting the Inventory to the

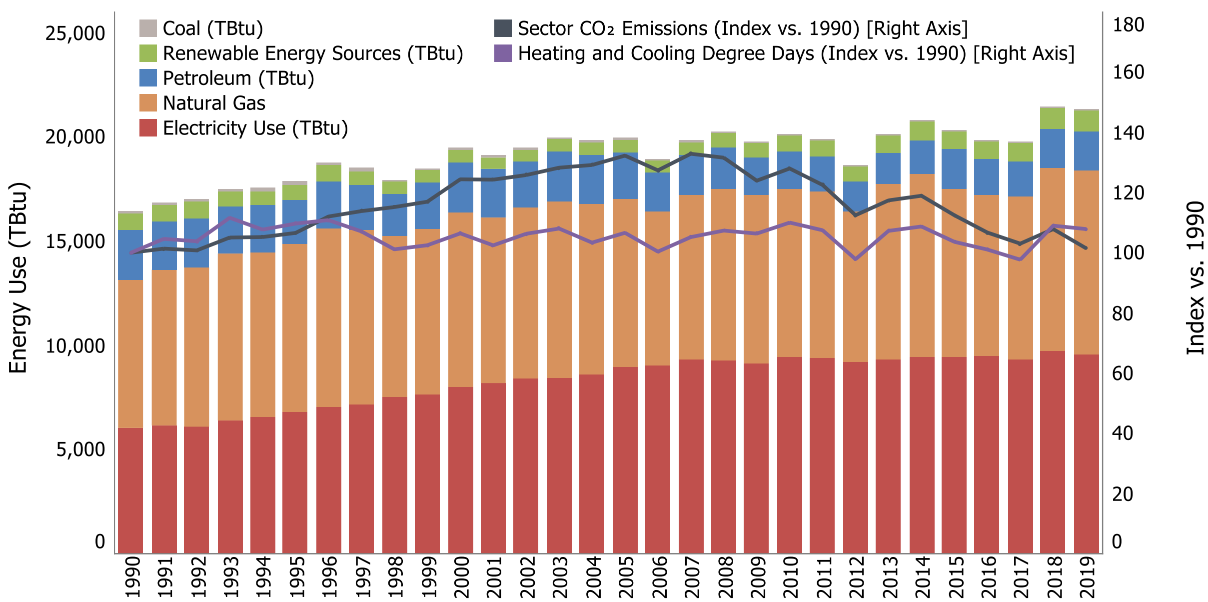
[19] See Section 4 "Use of Facility-Level Data in Good Practice National Greenhouse Gas Inventories" of the IPCC meeting report, and specifically the section on using facility-level data in conjunction with energy data, at <http://www.ipcc-nggip.iges.or.jp/public/tb/TFI_Technical_Bulletin_1.pdf>.

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) 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 2019 time period in the CRF tables. It is believed that the current analysis has led to improvements in the presentation of data in the Inventory, but further work will be conducted, and future improvements will be realized in subsequent Inventory reports. This includes incorporating the latest MECS data as it becomes available.

Residential and Commercial Sectors

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

Figure 3-13: Fuels and Electricity Used in Residential and Commercial Sectors, Heating and Cooling Degree Days, and Total Sector CO_2 Emissions (Including Electricity)



In 2019 the residential and commercial sectors accounted for 7 and 5 percent of CO_2 emissions from fossil fuel combustion, respectively; 42 and 11 percent of CH_4 emissions from fossil fuel combustion, respectively; and 2 and 1 percent of N_2O emissions from fossil fuel combustion, respectively. Emissions from these sectors were largely due to the direct consumption of natural gas and petroleum products, primarily for heating and cooking needs.

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

Coal consumption was a minor component of energy use in the commercial sector and did not contribute to any energy use in the residential sector. In 2019, total emissions (CO_2, CH_4, and N_2O) from fossil fuel combustion and electricity use within the residential and commercial end-use sectors were 933.9 MMT CO_2 Eq. and 811.4 MMT CO_2 Eq., respectively. Total CO_2, CH_4, and N_2O emissions from combined fossil fuel combustion and electricity use within the residential and commercial end-use sectors decreased by 6.1 and 5.8 percent from 2018 to 2019, respectively. A slight increase in heating degree days (0.6 percent) impacted energy demand for heating in the residential and commercial sectors. This was partially offset by a 5.4 percent decrease in cooling degree days compared to 2018, which reduced demand for air conditioning in the residential and commercial sectors. In addition, a shift toward energy efficient products and more stringent energy efficiency standards for household equipment has contributed to a decrease in energy demand in households (EIA 2020g), resulting in a decrease in energy-related emissions. In the long term, the residential sector is also affected by population growth, migration trends toward warmer areas, and changes in total housing units and building attributes (e.g., larger sizes and improved insulation).

In 2019, combustion emissions from natural gas consumption represented 82 and 77 percent of the direct fossil fuel CO_2 emissions from the residential and commercial sectors, respectively. Carbon dioxide emissions from natural gas combustion in the residential and commercial sectors in 2019 increased by 0.5 percent and 0.1 percent from 2018 to 2019, respectively.

U.S. Territories

Emissions from U.S. Territories are based on the fuel consumption in American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands. As described in the Methodology section of CO_2 from Fossil Fuel Combustion, this data is collected separately from the sectoral-level data available for the general calculations. As sectoral information is not available for U.S. Territories, CO_2, CH_4, and N_2O emissions are not presented for U.S. Territories in the tables above by sector, though the emissions will occur across all sectors and sources including stationary, transportation and mobile combustion sources.

Transportation Sector and Mobile Combustion

This discussion of transportation emissions follows the alternative method of presenting combustion emissions by allocating emissions associated with electricity generation to the transportation end-use sector, as presented in Table 3-11. Table 3-10 presents direct CO_2, CH_4, and N_2O emissions from all transportation sources (i.e., excluding emissions allocated to electricity consumption in the transportation end-use sector).

The transportation end-use sector and other mobile combustion accounted for 1,842.3 MMT CO_2 Eq. in 2019, which represented 36 percent of CO_2 emissions, 22 percent of CH_4 emissions, and 42 percent of N_2O emissions from fossil fuel combustion, respectively.[21] Fuel purchased in the United States for international aircraft and marine travel accounted for an additional 117.2 MMT CO_2 Eq. in 2019; these emissions are recorded as international bunkers and are not included in U.S. totals according to UNFCCC reporting protocols.

Transportation End-Use Sector

From 1990 to 2019, transportation emissions from fossil fuel combustion rose by 21 percent due, in large part, to 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 CO_2, CH_4 and N_2O emissions from some sources in the U.S. Territories (ships and boats, recreational boats, non-transportation mobile sources) and CH_4 and N_2O emissions from transportation rail electricity.

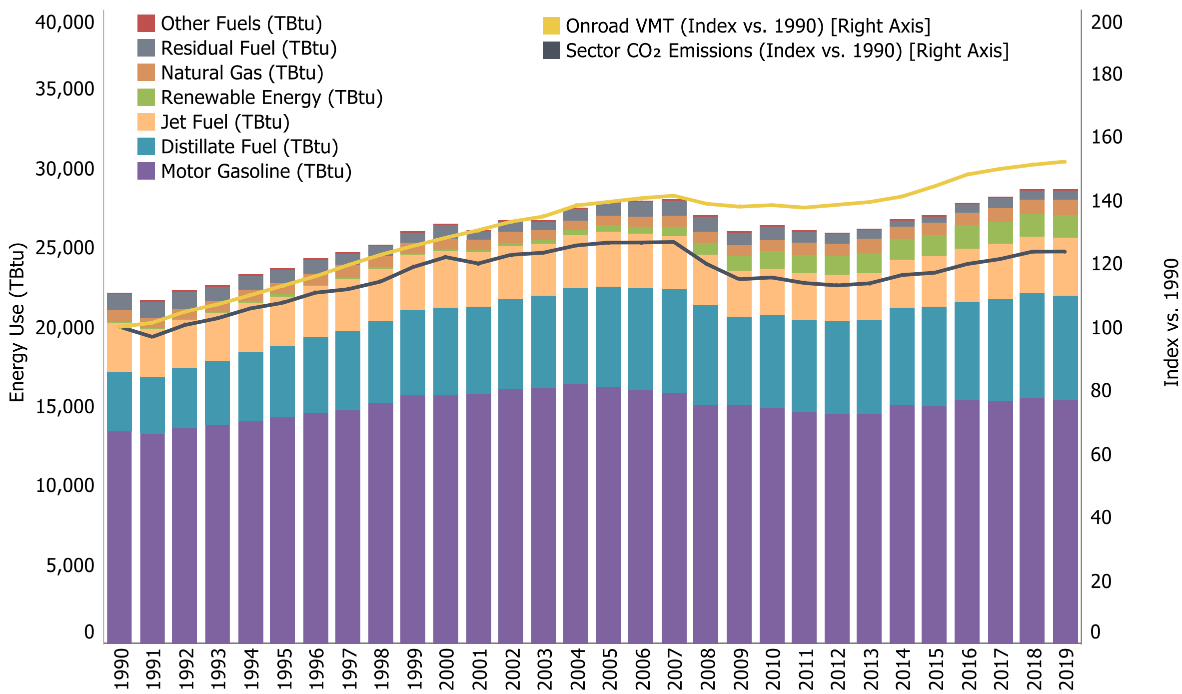
vehicles (passenger cars and light-duty trucks) increased 47 percent from 1990 to 2019,[22] as a result of a confluence of factors including population growth, economic growth, urban sprawl, and periods of low fuel prices.

From 2018 to 2019, CO_2 emissions from the transportation end-use sector increased by 0.04 percent. The small increase in emissions is primarily attributed to an increase in non-road fuel use, particularly jet fuel consumption.

Commercial aircraft emissions increased by 3.5 percent between 2018 and 2019, but have decreased 4 percent since 2007 (FAA 2021).[23] Decreases in jet fuel emissions (excluding bunkers) since 2007 are due in part to improved operational efficiency that results in more direct flight routing, improvements in aircraft and engine technologies to reduce fuel burn and emissions, and the accelerated retirement of older, less fuel-efficient aircraft.

Almost all of the energy consumed for transportation was supplied by petroleum-based products, with more than half being related to gasoline consumption in automobiles and other highway vehicles. Other fuel uses, especially diesel fuel for freight trucks and jet fuel for aircraft, accounted for the remainder. The primary driver of transportation-related emissions was CO_2 from fossil fuel combustion, which increased by 24 percent from 1990 to 2019. Annex 3.2 presents the total emissions from all transportation and mobile sources, including CO_2, N_2O, CH_4, and HFCs.

Figure 3-14: Fuels Used in Transportation Sector, Onroad VMT, and Total Sector CO_2 Emissions



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

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[22] VMT estimates are based on data from FHWA Highway Statistics Table VM-1 (FHWA 1996 through 2019). 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 2021), consists of passenger aircraft, cargo, and other chartered flights.

Transportation Fossil Fuel Combustion CO_2 Emissions

Domestic transportation CO_2 emissions increased by 24 percent (349.8 MMT CO_2) between 1990 and 2019, an annualized increase of 0.8 percent. Among domestic transportation sources in 2019, light-duty vehicles (including passenger cars and light-duty trucks) represented 58 percent of CO_2 emissions from fossil fuel combustion, medium- and heavy-duty trucks and buses 25 percent, commercial aircraft 7 percent, and other sources 10 percent. See Table 3-13 for a detailed breakdown of transportation CO_2 emissions by mode and fuel type.

Almost all of the energy consumed by the transportation sector is petroleum-based, including motor gasoline, diesel fuel, jet fuel, and residual oil. Carbon dioxide emissions from the combustion of ethanol and biodiesel for transportation purposes, along with the emissions associated with the agricultural and industrial processes involved in the production of biofuel, are captured in other Inventory sectors.[24] Ethanol consumption by the transportation sector has increased from 0.7 billion gallons in 1990 to 13.6 billion gallons in 2019, while biodiesel consumption has increased from 0.01 billion gallons in 2001 to 1.8 billion gallons in 2019. For additional information, see Section 3.11 on biofuel consumption at the end of this chapter and Table A-81 in Annex 3.2.

Carbon dioxide emissions from passenger cars and light-duty trucks totaled 1,052.6 MMT CO_2 in 2019. This is an increase of 14 percent (128.1 MMT CO_2) from 1990 due, in large part, to increased demand for travel as fleet-wide light-duty vehicle fuel economy was relatively stable (average new vehicle fuel economy declined slowly from 1990 through 2004 and then increased more rapidly from 2005 through 2019). Carbon dioxide emissions from passenger cars and light-duty trucks peaked at 1,154.7 MMT CO_2 in 2004, and since then have declined about 9 percent. The decline in new light-duty vehicle fuel economy between 1990 and 2004 (Figure 3-15) reflects the increasing market share of light-duty trucks, which grew from about 30 percent of new vehicle sales in 1990 to 48 percent in 2004. Starting in 2005, average new vehicle fuel economy began to increase while light-duty vehicle VMT grew only modestly for much of the period. Light-duty vehicle VMT grew by less than one percent or declined each year between 2005 and 2013,[25] then grew at a faster rate until 2016 (2.6 percent from 2014 to 2015, and 2.5 percent from 2015 to 2016). Since 2017, the rate of light-duty vehicle VMT growth slowed to less than one percent each year. Average new vehicle fuel economy has increased almost every year since 2005, while the light-duty truck share decreased to about 33 percent in 2009 and has since varied from year to year between 36 and 56 percent. Since 2014, light-duty truck share has slowly increased and is about 56 percent of new vehicles sales in model year 2019 (EPA 2019b). See Annex 3.2 for data by vehicle mode and information on VMT and the share of new vehicles (in VMT).

Medium- and heavy-duty truck CO_2 emissions increased by 90 percent from 1990 to 2019. This increase was largely due to a substantial growth in medium- and heavy-duty truck VMT, which increased by 109 percent between 1990 and 2019.[26] Carbon dioxide from the domestic operation of commercial aircraft increased by 22 percent (24.3 MMT CO_2) from 1990 to 2019.[27] Across all categories of aviation, excluding international bunkers, CO_2 emissions

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[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 2019 time period. In absence of these method changes, light-duty VMT growth between 2006 and 2007 would likely have been higher.

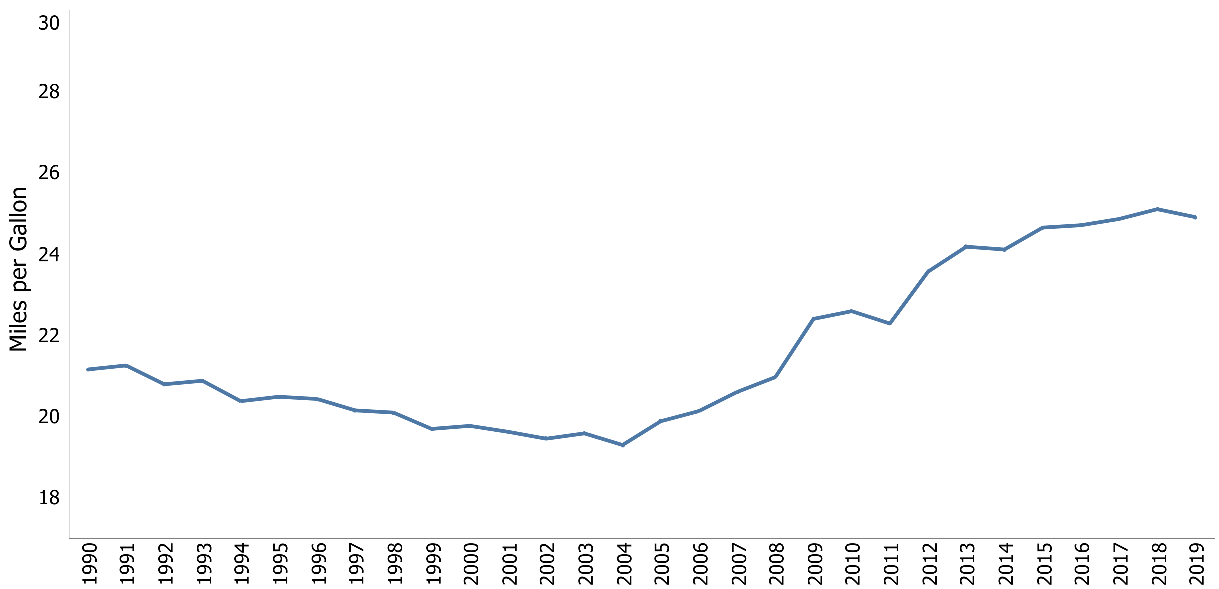
[26] While FHWA data shows consistent growth in medium- and heavy-duty truck VMT over the 1990 to 2019 time period, part of the growth reflects a method change for estimating VMT starting in 2007. This change in methodology in FHWA's VM-1 table resulted in large changes in VMT by vehicle class, thus 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.

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

decreased by 4 percent (7.9 MMT CO_2) between 1990 and 2019.[28] This includes a 66 percent (23.1 MMT CO_2) decrease in CO_2 emissions from domestic military operations.

Transportation sources also produce CH_4 and N_2O; these emissions are included in Table 3-14 and Table 3-15 and in the CH_4 and N_2O from Mobile Combustion section. Annex 3.2 presents total emissions from all transportation and mobile sources, including CO_2, CH_4, N_2O, and HFCs.

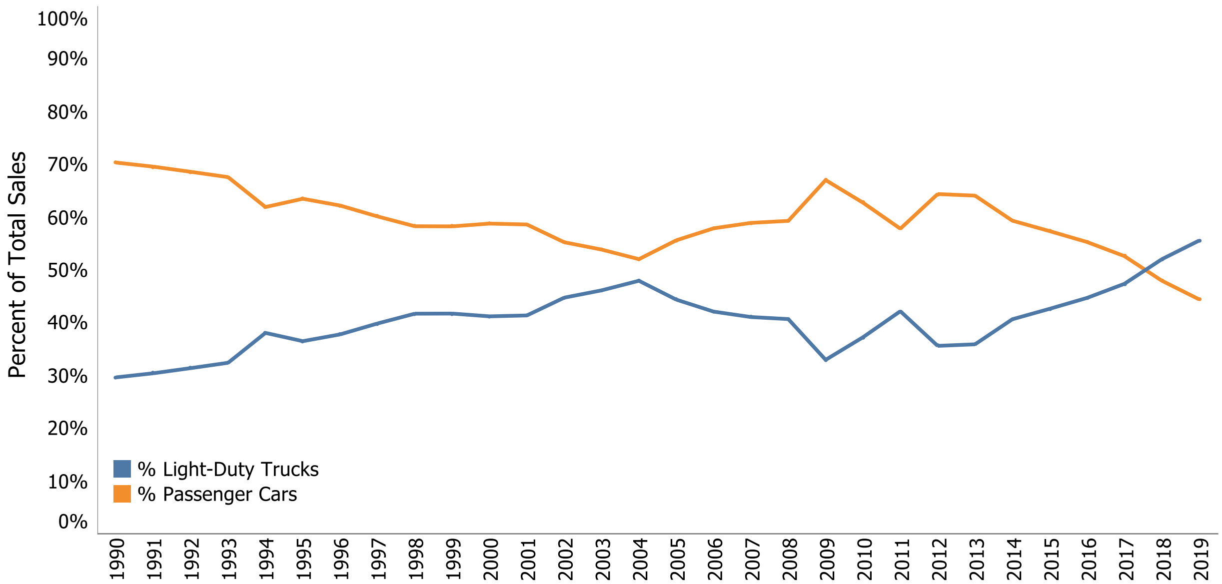
Figure 3-15: Sales-Weighted Fuel Economy of New Passenger Cars and Light-Duty Trucks, 1990–2019



Source: EPA (2020a).

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

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



Source: EPA (2019b).

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

Fuel/Vehicle Type	1990	2005	2015[a]	2016[a]	2017[a]	2018[a]	2019[a]
Gasoline[b]	**958.9**	**1,150.1**	**1,058.6**	**1,084.8**	**1,081.8**	**1,097.1**	**1,086.8**
Passenger Cars	604.3	637.1	724.3	737.8	737.4	748.8	742.3
Light-Duty Trucks	300.6	463.5	280.5	291.8	288.2	290.9	289.1
Medium- and Heavy-Duty Trucks[c]	37.7	33.8	38.9	40.0	40.9	41.9	40.1
Buses	0.3	0.4	0.9	0.9	0.9	1.0	1.0
Motorcycles	1.7	1.6	3.6	3.8	3.7	3.8	3.6
Recreational Boats[d]	14.3	13.7	10.5	10.6	10.6	10.7	10.7
Distillate Fuel Oil (Diesel)[b]	**262.9**	**462.6**	**457.5**	**454.2**	**468.3**	**480.2**	**481.1**
Passenger Cars	7.9	4.3	4.3	4.3	4.3	4.4	4.6
Light-Duty Trucks	11.5	26.1	13.8	14.1	14.1	14.2	14.9
Medium- and Heavy-Duty Trucks[c]	190.5	364.2	366.8	369.3	381.6	390.9	394.8
Buses	8.0	10.7	17.0	16.6	17.9	19.1	19.3
Rail	35.5	46.1	39.8	36.3	37.5	39.4	37.1
Recreational Boats[d]	2.7	2.9	2.6	2.7	2.8	2.9	2.9
Ships and Non-Recreational Boats[e]	6.8	8.4	13.2	10.9	10.1	9.4	7.6
International Bunker Fuels[f]	11.7	9.5	8.4	8.7	9.0	10.0	10.1
Jet Fuel	**184.2**	**189.3**	**157.6**	**166.0**	**171.8**	**172.3**	**177.8**
Commercial Aircraft[g]	109.9	132.7	119.0	120.4	128.0	129.6	134.2
Military Aircraft	35.0	19.4	13.5	12.3	12.2	11.8	11.9
General Aviation Aircraft	39.4	37.3	25.1	33.4	31.5	30.9	31.7
International Bunker Fuels[f]	38.0	60.1	71.9	74.1	77.7	80.8	80.7
International Bunker Fuels from Commercial Aviation	30.0	55.6	68.6	70.8	74.5	77.7	77.6
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
International Bunker Fuels[f]	53.7	43.6	30.6	33.8	33.4	31.4	25.2
Natural Gas[j]	**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
LPG[j]	**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	+	0.1	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**	**1,863.4**	**1,723.5**	**1,764.1**	**1,786.8**	**1,821.2**	**1,821.9**
Total (Including Bunkers)[f]	**1,575.6**	**1,976.6**	**1,834.4**	**1,880.7**	**1,906.9**	**1,943.3**	**1,938.0**
Biofuels-Ethanol[i]	4.1	*21.6*	74.2	76.9	77.7	78.6	78.7
Biofuels-Biodiesel[i]	*+*	*0.9*	*14.1*	*19.6*	*18.7*	*17.9*	*17.1*

Notes: This table does not include emissions from non-transportation mobile sources, such as agricultural equipment and construction/mining equipment; it also does not include emissions associated with electricity consumption by pipelines or lubricants used in transportation. In addition, this table does not include CO_2 emissions from U.S. Territories, since these are covered in a separate chapter of the Inventory. Totals may not sum due to independent rounding.

\+ Does not exceed 0.05 MMT CO_2 Eq.

[a] In 2011, FHWA changed its methods for estimating vehicle miles traveled (VMT) and related data. These methodological changes included how vehicles are classified, moving from a system based on body-type to one that is based on wheelbase. These changes were first incorporated for the 1990 through 2010 Inventory and apply to the 2007 through 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.

[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). 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 CO_2 emissions from natural gas-powered pipelines transporting natural gas.

[i] Ethanol and biodiesel estimates are presented for informational purposes only. See Section 3.11 of this chapter and the estimates in Land Use, Land-Use Change, and Forestry (see Chapter 6), in line with IPCC methodological guidance and UNFCCC reporting obligations, for more information on ethanol and biodiesel.

[j] Transportation sector natural gas and LPG consumption are based on data from EIA (2019b). Prior to the 1990 to 2015 Inventory, data from DOE TEDB were used to estimate each vehicle class's share of the total natural gas and LPG consumption. Since TEDB does not include estimates for natural gas use by medium and heavy-duty trucks or LPG use by

passenger cars, EIA Alternative Fuel Vehicle Data (Browning 2017) is now used to determine each vehicle class's share of the total natural gas and LPG consumption. These changes were first incorporated in the 1990 to 2016 Inventory and apply to the 1990 to 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, CO_2 emissions from electric vehicle charging were allocated to the residential and commercial sectors. They are now allocated to the transportation sector. These changes apply to the 2010 through 2019 time period.

Mobile Fossil Fuel Combustion CH_4 and N_2O Emissions

Mobile combustion includes emissions of CH_4 and N_2O from all transportation sources identified in the U.S. Inventory with the exception of pipelines and electric locomotives;[29] mobile sources also include non-transportation sources such as construction/mining equipment, agricultural equipment, vehicles used off-road, and other sources (e.g., snowmobiles, lawnmowers, etc.).[30] Annex 3.2 includes a summary of all emissions from both transportation and mobile sources. Table 3-14 and Table 3-15 provide mobile fossil fuel CH_4 and N_2O emission estimates in MMT CO_2 Eq.[31]

Mobile combustion was responsible for a small portion of national CH_4 emissions (0.4 percent) and was the fifth largest source of national N_2O emissions (4.4 percent). From 1990 to 2019, mobile source CH_4 emissions declined by 63 percent, to 2.4 MMT CO_2 Eq. (95 kt CH_4), due largely to emissions control technologies employed in on-road vehicles since the mid-1990s to reduce CO, NO_x, NMVOC, and CH_4 emissions. Mobile source emissions of N_2O decreased by 60 percent from 1990 to 2019, to 18.0 MMT CO_2 Eq. (60 kt N_2O). Earlier generation emissions control technologies initially resulted in higher N_2O emissions, causing a 29 percent increase in N_2O emissions from mobile sources between 1990 and 1997. Improvements in later-generation emissions control technologies have reduced N_2O emissions, resulting in a 69 percent decrease in mobile source N_2O emissions from 1997 to 2019 (Figure 3-17). Overall, CH_4 and N_2O emissions were predominantly from gasoline-fueled passenger cars and light-duty trucks and non-highway sources. See Annex 3.2 for data by vehicle mode and information on VMT and the share of new vehicles (in VMT).

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

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

[31] See Annex 3.2 for a complete time series of emission estimates for 1990 through 2019.

Figure 3-17: Mobile Source CH_4 and N_2O Emissions

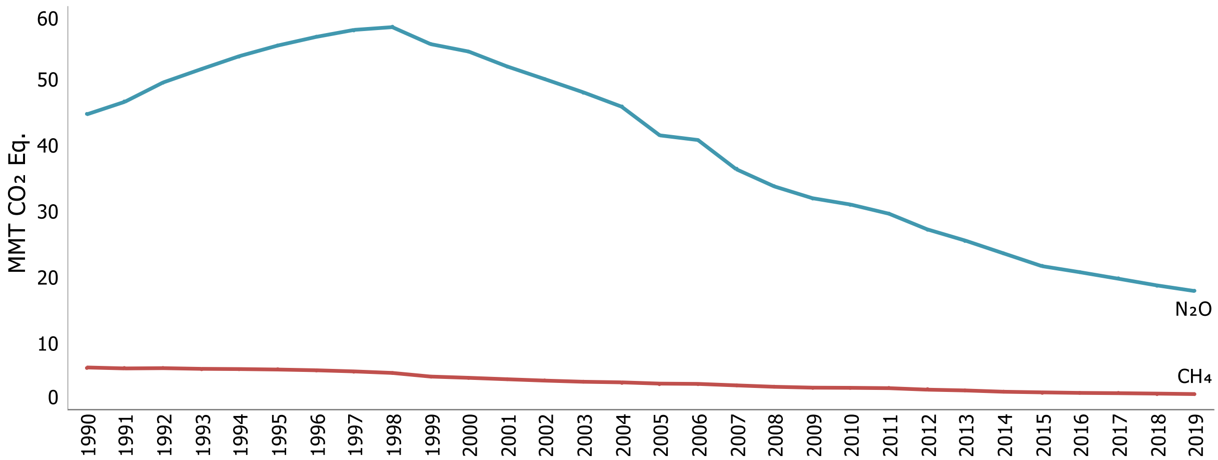


Table 3-14: CH_4 Emissions from Mobile Combustion (MMT CO_2 Eq.)

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	+	+	+	+
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]	**1.2**	**1.5**	**1.4**	**1.4**	**1.4**	**1.4**	**1.4**
Ships and Boats	0.4	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**	**4.0**	**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 CO_2 Eq.

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

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

[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.

Table 3-15: N_2O Emissions from Mobile Combustion (MMT CO_2 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**	**3.0**
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	2.8
Alternative Fuel On-Road	**+**	**+**	**0.1**	**0.2**	**0.2**	**0.2**	**0.2**
Non-Road	**7.1**	**9.4**	**7.9**	**8.1**	**8.4**	**8.5**	**8.7**
Ships and Boats	0.3	0.3	0.2	0.2	0.2	0.2	0.2
Rail[c]	0.3	0.3	0.3	0.3	0.3	0.3	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	**44.7**	**41.6**	**21.7**	**20.8**	**19.8**	**18.8**	**18.0**

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 CO_2 Eq.
[a] See Annex 3.2 for definitions of on-road vehicle types.
[b] Gasoline and diesel highway vehicle mileage estimates are based on data from FHWA Highway Statistics Table VM-1.
[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.

CO_2 from Fossil Fuel Combustion

Methodology

CO_2 emissions from fossil fuel combustion are estimated in line with a Tier 2 method described by the IPCC in the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC 2006) with some exceptions as discussed below.[32] A detailed description of the U.S. methodology is presented in Annex 2.1, and is characterized by the following steps:

1. *Determine total fuel consumption by fuel type and sector*. Total fossil fuel consumption for each year is estimated by aggregating consumption data by end-use sector (e.g., commercial, industrial), primary fuel type (e.g., coal, petroleum, gas), and secondary fuel category (e.g., motor gasoline, distillate fuel oil). Fuel consumption data for the United States were obtained directly from the EIA of the U.S. Department of Energy (DOE), primarily from the *Monthly Energy Review* (EIA 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 CO_2 Eq. in 2019.

[34] See IPCC Reference Approach for Estimating CO_2 Emissions from Fossil Fuel Combustion in Annex 4 for a comparison of U.S. estimates using top-down and bottom-up approaches.

[35] A crude convention to convert between gross and net calorific values is to multiply the heat content of solid and liquid fossil fuels by 0.95 and gaseous fuels by 0.9 to account for the water content of the fuels. Biomass-based fuels in U.S. energy statistics, however, are generally presented using net calorific values.

through 2017a), USGS (2014 through 2020a), USGS (1991 through 2015b), USGS (2020b), USGS (1991 through 2017).[36]

3. *Adjust for biofuels and petroleum denaturant*. Fossil fuel consumption estimates are adjusted downward to exclude fuels with biogenic origins and avoid double counting in petroleum data statistics. Carbon dioxide emissions from ethanol added to motor gasoline and biodiesel added to diesel fuel are not included specifically in summing energy sector totals. Net carbon fluxes from changes in biogenic carbon reservoirs are accounted for in the estimates for LULUCF, therefore, fuel consumption estimates are adjusted to remove ethanol and biodiesel.[37] For the years 1993 through 2008, petroleum denaturant is currently included in EIA statistics for both natural gasoline and finished motor gasoline. To avoid double counting, petroleum denaturant is subtracted from finished motor gasoline for these years.[38]
4. *Adjust for exports of CO_2.* Since October 2000, the Dakota Gasification Plant has been exporting CO_2 produced in the coal gasification process to Canada by pipeline. Because this CO_2 is not emitted to the atmosphere in the United States, the associated fossil fuel (lignite coal) that is gasified to create the exported CO_2 is subtracted from EIA (2020d) coal consumption statistics that are used to calculate greenhouse gas emissions from the Energy Sector. The associated fossil fuel is the total fossil fuel burned at the plant with the CO_2 capture system multiplied by the fraction of the plant's total site-generated CO_2 that is recovered by the capture system. To make these adjustments, data for CO_2 exports were collected from Environment and Climate Change Canada (2020). A discussion of the methodology used to estimate the amount of CO_2 captured and exported by pipeline is presented in Annex 2.1.
5. *Adjust sectoral allocation of distillate fuel oil and motor gasoline.* EPA conducted a separate bottom-up analysis of transportation fuel consumption based on data from the Federal Highway Administration that indicated that the amount of distillate and motor gasoline consumption allocated to the transportation sector in the EIA statistics should be adjusted. Therefore, for these estimates, the transportation sector's distillate fuel and motor gasoline consumption were adjusted to match the value obtained from the bottom-up analysis. As the total distillate and motor gasoline consumption estimate from EIA are considered to be accurate at the national level, the distillate and motor gasoline consumption totals for the residential, commercial, and industrial sectors were adjusted proportionately. The data sources used in the bottom-up analysis of transportation fuel consumption include AAR (2008 through 2018), Benson (2002 through 2004), DOE (1993 through 2017), EIA (2007), EIA (1991 through 2019), EPA (2018), and FHWA (1996 through 2018).[39]
6. *Adjust for fuels consumed for non-energy uses*. U.S. aggregate energy statistics include consumption of fossil fuels for non-energy purposes. These are fossil fuels that are manufactured into plastics, asphalt, lubricants, or other products. Depending on the end-use, this can result in storage of some or all of the C contained in the fuel for a period of time. As the emission pathways of C used for non-energy purposes are vastly different than fuel combustion (since the C in these fuels ends up in products instead of being combusted), these emissions are estimated separately in Section 3.2 – Carbon Emitted and Stored in Products from Non-Energy Uses of Fossil Fuels. Therefore, the amount of fuels used for non-energy purposes was subtracted from total fuel consumption. Data on non-fuel consumption were provided by EIA (2020c).
7. *Subtract consumption of international bunker fuels.* According to the UNFCCC reporting guidelines emissions from international transport activities, or bunker fuels, should not be included in national totals. U.S. energy consumption statistics include these bunker fuels (e.g., distillate fuel oil, residual fuel oil, and jet fuel) as part of consumption by the transportation end-use sector, however, so emissions from

[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] 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).

international transport activities were calculated separately following the same procedures used to calculate emissions from consumption of all fossil fuels (i.e., estimation of consumption, and determination of Carbon content).[40] The Office of the Under Secretary of Defense (Installations and Environment) and the Defense Logistics Agency Energy (DLA Energy) of the U.S. Department of Defense (DoD) (DLA Energy 2020) supplied data on military jet fuel and marine fuel use. Commercial jet fuel use was obtained from FAA (2021); residual and distillate fuel use for civilian marine bunkers was obtained from DOC (1991 through 2019) for 1990 through 2001 and 2007 through 2018, and DHS (2008) for 2003 through 2006.[41] Consumption of these fuels was subtracted from the corresponding fuels totals in the transportation end-use sector. Estimates of international bunker fuel emissions for the United States are discussed in detail in Section 3.10 – International Bunker Fuels.

8. *Determine the total Carbon content of fuels consumed.* Total C was estimated by multiplying the amount of fuel consumed by the amount of C in each fuel. This total C estimate defines the maximum amount of C that could potentially be released to the atmosphere if all of the C in each fuel was converted to CO_2. A discussion of the methodology and sources used to develop the C content coefficients are presented in Annexes 2.1 and 2.2.
9. *Estimate CO_2 Emissions.* Total CO_2 emissions are the product of the adjusted energy consumption (from the previous methodology steps 1 through 6), the Carbon content of the fuels consumed, and the fraction of C that is oxidized. The fraction oxidized was assumed to be 100 percent for petroleum, coal, and natural gas based on guidance in IPCC (2006) (see Annex 2.1). Carbon emissions were multiplied by the molecular-to-atomic weight ratio of CO_2 to C (44/12) to obtain total CO_2 emitted from fossil fuel combustion in million metric tons (MMT).
10. *Allocate transportation emissions by vehicle type.* This report provides a more detailed accounting of emissions from transportation because it is such a large consumer of fossil fuels in the United States. For fuel types other than jet fuel, fuel consumption data by vehicle type and transportation mode were used to allocate emissions by fuel type calculated for the transportation end-use sector. Heat contents and densities were obtained from EIA (2020c) and USAF (1998).[42]
    - For on-road vehicles, annual estimates of combined motor gasoline and diesel fuel consumption by vehicle category were obtained from FHWA (1996 through 2019); for each vehicle category, the percent gasoline, diesel, and other (e.g., CNG, LPG) fuel consumption are estimated using data from DOE (1993 through 2018). [43,44]
    - For non-road vehicles, activity data were obtained from AAR (2008 through 2019), APTA (2007 through 2018), APTA (2006), BEA (2020), Benson (2002 through 2004), DLA Energy (2019), DOC (1991 through 2019), DOE (1993 through 2017), DOT (1991 through 2019), EIA (2009a), EIA (2020c), EIA

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

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

[42] For a more detailed description of the data sources used for the analysis of the transportation end use sector see the Mobile Combustion (excluding CO_2) and International Bunker Fuels sections of the Energy chapter, Annex 3.2, and Annex 3.8, respectively.

[43] Data from FHWA's Table VM-1 is used to estimate the share of fuel consumption between each on-road vehicle class. These fuel consumption estimates are combined with estimates of fuel shares by vehicle type from DOE's TEDB Annex Tables A.1 through A.6 (DOE 1993 through 2017). In 2011, FHWA changed its methods for estimating data in the VM-1 table. These methodological changes included how vehicles are classified, moving from a system based on body-type to one that is based on wheelbase. These changes were first incorporated for the 1990 through 2010 Inventory and apply to the time period from 2007 through 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.

[44] 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.

(2019f), EIA (1991 through 2019), EPA (2018),[45] and Gaffney (2007).

- For jet fuel used by aircraft, CO_2 emissions from commercial aircraft were developed by the U.S. Federal Aviation Administration (FAA) using a Tier 3B methodology, consistent IPCC (2006) (see Annex 3.3). Carbon dioxide emissions from other aircraft were calculated directly based on reported consumption of fuel as reported by EIA. Allocation to domestic military uses was made using DoD data (see Annex 3.8). General aviation jet fuel consumption is calculated as the remainder of total jet fuel use (as determined by EIA) nets all other jet fuel use as determined by FAA and DoD. For more information, see Annex 3.2.

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

The amount of C emitted from the combustion of fossil fuels is dependent upon the carbon content of the fuel and the fraction of that C that is oxidized. Fossil fuels vary in their average carbon content, ranging from about 53 MMT CO_2 Eq./QBtu for natural gas to upwards of 95 MMT CO_2 Eq./QBtu for coal and petroleum coke (see Tables A-42 and A-43 in Annex 2.1 for carbon contents of all fuels). In general, the carbon content per unit of energy of fossil fuels is the highest for coal products, followed by petroleum, and then natural gas. The overall carbon intensity of the U.S. economy is thus dependent upon the quantity and combination of fuels and other energy sources employed to meet demand.

Table 3-16 provides a time series of the carbon intensity of direct emissions for each sector of the U.S. economy. The time series incorporates only the energy from the direct combustion of fossil fuels in each sector. For example, the carbon intensity for the residential sector does not include the energy from or emissions related to the use of electricity for lighting, as it is instead allocated to the electric power sector. For the purposes of maintaining the focus of this section, renewable energy and nuclear energy are not included in the energy totals used in Table 3-16 in order to focus attention on fossil fuel combustion as detailed in this chapter. Looking only at this direct consumption of fossil fuels, the residential sector exhibited the lowest carbon intensity, which is related to the large percentage of its energy derived from natural gas for heating. The carbon intensity of the commercial sector has predominantly declined since 1990 as commercial businesses shift away from petroleum to natural gas. The industrial sector was more dependent on petroleum and coal than either the residential or commercial sectors, and thus had higher C intensities over this period. The Carbon intensity of the transportation sector was closely related to the Carbon content of petroleum products (e.g., motor gasoline and jet fuel, both around 70 MMT CO_2 Eq./QBtu), which were the primary sources of energy. Lastly, the electric power sector had the highest Carbon intensity due to its heavy reliance on coal for generating electricity.

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

Sector	1990		2005		2015	2016	2017	2018	2019
Residential[a]	57.4		56.8		55.5	55.2	55.1	55.3	55.1
Commercial[a]	59.7		57.8		57.1	56.7	56.5	56.0	56.1
Industrial[a]	64.5		64.6		61.4	61.0	60.8	60.5	60.3
Transportation[a]	71.1		71.5		71.1	71.1	71.2	71.0	71.0
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	71.0	71.3	71.3	71.3
All Sectors[c]	**73.1**		**73.6**		**69.6**	**69.2**	**69.1**	**68.3**	**67.3**

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

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

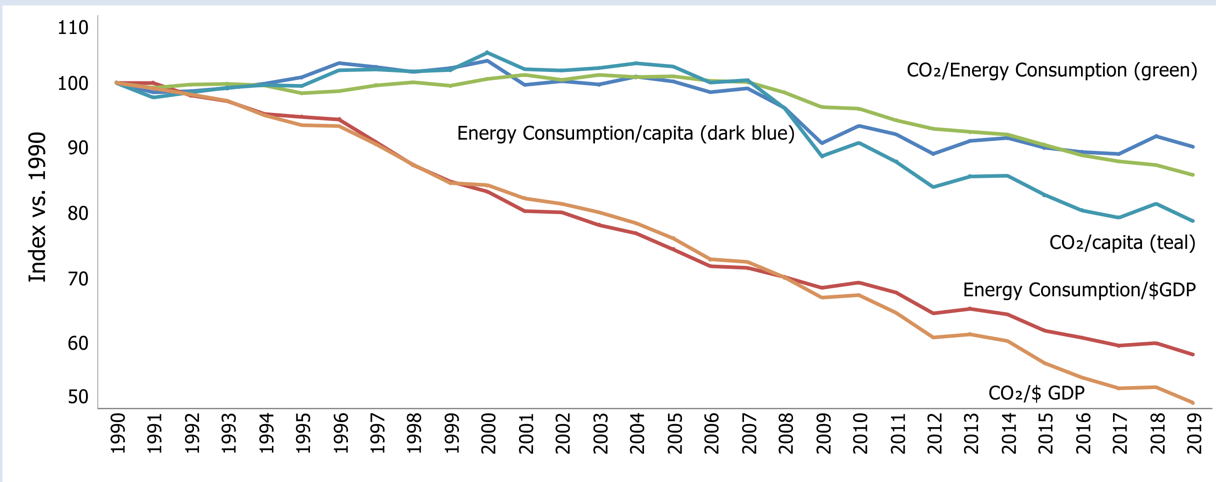
[b] Does not include electricity produced using nuclear or renewable energy.

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

[45] In 2014, EPA incorporated the NONROAD2008 model into MOVES2014. The current Inventory uses the Nonroad component of MOVES2014b for years 1999 through 2019.

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 CO_2 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 CO_2 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.

Uncertainty and Time-Series Consistency

For estimates of CO_2 from fossil fuel combustion, the amount of CO_2 emitted is directly related to the amount of fuel consumed, the fraction of the fuel that is oxidized, and the carbon content of the fuel. Therefore, a careful accounting of fossil fuel consumption by fuel type, average carbon contents of fossil fuels consumed, and production of fossil fuel-based products with long-term carbon storage should yield an accurate estimate of CO_2 emissions.

Nevertheless, there are uncertainties in the consumption data, carbon content of fuels and products, and carbon oxidation efficiencies. For example, given the same primary fuel type (e.g., coal, petroleum, or natural gas), the amount of carbon contained in the fuel per unit of useful energy can vary. For the United States, however, the impact of these uncertainties on overall CO_2 emission estimates is believed to be relatively small. See, for example, Marland and Pippin (1990). See also Annex 2.2 for a discussion of uncertainties associated with fuel carbon contents. Recent updates to carbon factors for natural gas and coal utilized the same approach as previous Inventories with updated recent data, therefore, the uncertainty estimates around carbon contents of the different fuels as outlined in Annex 2.2 were not impacted and the historic uncertainty ranges still apply.

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

To calculate the total CO_2 emission estimate from energy-related fossil fuel combustion, the amount of fuel used in non-energy production processes were subtracted from the total fossil fuel consumption. The amount of CO_2 emissions resulting from non-energy related fossil fuel use has been calculated separately and reported in the Carbon Emitted from Non-Energy Uses of Fossil Fuels section of this report (Section 3.2). These factors all contribute to the uncertainty in the CO_2 estimates. Detailed discussions on the uncertainties associated with C emitted from Non-Energy Uses of Fossil Fuels can be found within that section of this chapter.

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

Uncertainties in the emission estimates presented above also result from the data used to allocate CO_2 emissions from the transportation end-use sector to individual vehicle types and transport modes. In many cases, bottom-up estimates of fuel consumption by vehicle type do not match aggregate fuel-type estimates from EIA. Further research is planned to improve the allocation into detailed transportation end-use sector emissions.

The uncertainty analysis was performed by primary fuel type for each end-use sector, using the IPCC-recommended Approach 2 uncertainty estimation methodology, Monte Carlo Stochastic Simulation technique, with @RISK software. For this uncertainty estimation, the inventory estimation model for CO_2 from fossil fuel combustion was integrated with the relevant variables from the inventory estimation model for International Bunker Fuels, to realistically characterize the interaction (or endogenous correlation) between the variables of these two models. About 170 input variables were modeled for CO_2 from energy-related Fossil Fuel Combustion (including about 20 for non-energy fuel consumption and about 20 for International Bunker Fuels).

In developing the uncertainty estimation model, uniform distributions were assumed for all activity-related input variables and emission factors, based on the SAIC/EIA (2001) report.[46] Triangular distributions were assigned for the oxidization factors (or combustion efficiencies). The uncertainty ranges were assigned to the input variables based on the data reported in SAIC/EIA (2001) and on conversations with various agency personnel.[47]

The uncertainty ranges for the activity-related input variables were typically asymmetric around their inventory estimates; the uncertainty ranges for the emissions factors were symmetric. Bias (or systematic uncertainties) associated with these variables accounted for much of the uncertainties associated with these variables (SAIC/EIA 2001).[48] For purposes of this uncertainty analysis, each input variable was simulated 10,000 times through Monte

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

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

[48] Although, in general, random uncertainties are the main focus of statistical uncertainty analysis, when the uncertainty estimates are elicited from experts, their estimates include both random and systematic uncertainties. Hence, both these types of uncertainties are represented in this uncertainty analysis.

Carlo sampling.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-17. Fossil fuel combustion CO_2 emissions in 2019 were estimated to be between 4,757.7 and 5,073.0 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 2 percent below to 4 percent above the 2019 emission estimate of 4,856.7 MMT CO_2 Eq.

Table 3-17: Approach 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Energy-Related Fossil Fuel Combustion by Fuel Type and Sector (MMT CO_2 Eq. and Percent)

Fuel/Sector	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]	**1,027.1**	**991.9**	**1,125.1**	**-3%**	**10%**
Residential	NO	NO	NO	NO	NO
Commercial	1.6	1.5	1.8	-5%	15%
Industrial	49.5	47.1	57.2	-5%	16%
Transportation	NO	NO	NO	NO	NO
Electric Power	973.5	935.8	1,068.4	-4%	10%
U.S. Territories	2.5	2.2	3.0	-12%	19%
Natural Gas[b]	**1,644.6**	**1,625.8**	**1,720.0**	**-1%**	**5%**
Residential	275.3	267.5	294.6	-3%	7%
Commercial	192.8	187.4	206.3	-3%	7%
Industrial	503.3	486.5	540.5	-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]	**2,184.6**	**2,054.4**	**2,313.2**	**-6%**	**6%**
Residential	61.5	58.0	64.8	-6%	5%
Commercial	55.3	52.3	58.1	-5%	5%
Industrial	269.7	215.7	324.3	-20%	20%
Transportation	1,762.5	1,649.9	1,873.9	-6%	6%
Electric Power	16.2	15.4	17.5	-5%	8%
U.S. Territories	19.5	18.0	21.7	-8%	11%
Total (excluding Geothermal)[b]	**4,856.3**	**4,757.1**	**5,072.4**	**-2%**	**4%**
Geothermal	**0.4**	**NE**	**NE**	**NE**	**NE**
Electric Power	0.4	NE	NE	NE	NE
Total (including Geothermal)[b,c]	**4,856.7**	**4,757.7**	**5,073.0**	**-2%**	**4%**

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

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990 through 2019. Details on the emission trends through time are described in more detail in the Methodology section, above. As discussed in Annex 5, data are unavailable to include estimates of CO_2 emissions from any liquid fuel used in pipeline transport or non-hazardous industrial waste incineration, but those emissions are assumed to be insignificant.

QA/QC and Verification

In order to ensure the quality of the CO_2 emission estimates from fossil fuel combustion, general (IPCC Tier 1) and category-specific (Tier 2) Quality Assurance/Quality Control (QA/QC) procedures were implemented consistent with the U.S. Inventory QA/QC plan outlined in Annex 8. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and methodology used for estimating CO_2 emissions from fossil fuel combustion in the United States. Emission totals for the different sectors and fuels were compared and trends were investigated to determine whether any corrective actions were needed. Minor corrective actions were taken.

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

Recalculations Discussion

Several updates to activity data and emission factors lead to recalculations of previous year results. The major updates are as follows:

- EIA (2020c) updated energy consumption statistics across the time series relative to the previous Inventory. As a result of revised natural gas heat contents, EIA updated natural gas consumption in the residential, commercial, and industrial sectors for 2018. Approximate heat rates for electricity and the heat content of electricity were revised for natural gas and noncombustible renewable energy, which impacted electric power energy consumption by sector. EIA also revised sector allocations for distillate fuel oil, residual fuel oil, and kerosene for 2018, and for propane for 2010 through 2012, 2014, 2017, and 2018, which impacted LPG by sector. EIA revised product supplied totals for crude oil and petroleum products, which impacted the nonfuel sequestration statistics, particularly for lubricants for 2018 and LPG for 2010 through 2018 relative to the previous Inventory. This resulted in a slight decrease in energy used in the industrial sector.
- To align with EIA’s methodology for calculating motor gasoline consumption, petroleum denaturant adjustments to motor gasoline consumption for the period 1993 through 2008 were corrected. This resulted in an average annual decrease of 6.2 TBtu in motor gasoline consumption for the period 1993 through 2008, which led to a decrease in emissions from gasoline consumption in those years because denaturant emissions were previously being double counted.
- Newly published U.S. Territories data from EIA (2020e) was integrated, which impacted total estimates for U.S. Territories across the time series. This resulted in the following observed changes:
    - average annual decrease of 0.3 MMT CO_2 Eq. (21.3 percent) in coal use across the time series;
    - decrease of 0.01 MMT CO_2 Eq. (0.48 percent) in natural gas use across the time series; and
    - decrease in petroleum use from 1990 through 1999, increase in petroleum use from 2000 through 2008, then a decrease from 2009 through 2018, resulting in an average annual decrease of 5.8 MMT CO_2 eq. (17.9 percent) in petroleum use across the time series.

- Updated MECS data for 2018 resulted in an increase in natural gas used in non-energy use. This resulted in a decrease in natural gas used in the industrial sector as part of fossil fuel combustion estimates. The updates mainly impacted years 2014-2018. See Section 3.2 for more details on NEU emissions and adjustments.
- EPA (2020c) revised distillate fuel oil and motor gasoline carbon contents, which impacted petroleum consumption in the transportation, residential, commercial, and industrial sectors. The combined effect of both the diesel fuel and gasoline emission factor update was an increase in emissions early in the time series and then decreases in emissions in more recent years. For years 1990 through 2005, the average annual increase in total emissions was approximately 7 MMT CO_2 (0.1 percent of emissions). For the years 2006 to 2018 the average annual decrease in total emissions is about 5 MMT CO_2 (less than 0.1 percent of emissions).
- EPA also revised HGL C contents to align with EIA's revised heat contents and HGL fuel type categorization (EIA 2020c; ICF 2020). A discussion of the methodology used to develop the C content coefficients is presented in Annex 2.2. This resulted in an average annual increase of 3.0 percent in the weighted industrial HGL C contents.
- To account for coal consumed during the production of coke oven gas (COG) and blast furnace gas (BFG) for energy purposes (e.g., as an input to the natural gas distribution system), consumption of COG and BFG was included in industrial coal consumption estimates in the energy sector, in alignment with EIA's methodology (EIA 2020c). Previously, COG and BFG consumption that enters the natural gas distribution system was removed from industrial natural gas consumption estimates in the energy sector. These adjustments are explained in greater detail in Annex 2.1. This resulted in an average annual increase of 1.5 TBtu (48 percent) in coal use between 1990 through 1992, no change between 1993 through 1999, an average annual decrease of 0.5 TBtu (146 percent) between 2000 and 2001, and no change from 2002 forward.
- The Dakota Gasification Plant uses a coal gasification process that produces synthetic natural gas (SNG) from lignite coal. Coal consumption at this plant is included in EIA's statistics for industrial coal consumption, which is used to estimate CO_2 emissions from coal combustion in the U.S. Inventory. Previously, coal consumption for the production of SNG was subtracted from industrial coal consumption statistics. However, SNG is not included in industrial natural gas consumption data in EIA's MER and rather, SNG is accounted for in its primary energy category (e.g., gasification of coal). To account for SNG from coal gasification, the adjustment to industrial coal consumption to subtract the quantity of SNG produced was removed. These adjustments are explained in greater detail in Annex 2.1. This resulted in an average annual increase in coal use across the time series of 31.9 Tbtu (3 percent).
- The Dakota Gasification Plant also produces CO_2 as a byproduct. A fraction of the plant's total site-generated CO_2 that is captured by the plant's CO_2 capture system is exported by pipeline to Canada. The remainder of the byproduct CO_2 is emitted to the atmosphere. Because the exported CO_2 is not emitted to the atmosphere in the United States, the amount of associated fossil fuel (lignite coal) that is gasified to create the exported CO_2 is subtracted from the EIA industrial coal consumption statistics used in the Inventory, so that the amount of CO_2 exported is not included in the reported greenhouse gas emissions from the Energy Sector. Previously, the amount of CO_2 captured and exported by pipeline annually was estimated from publicly available data for plant operations, including historical CO_2 export data and the publicly reported transport (CO_2 gas compressor) capacity of the CO_2 pipeline, assuming that the CO_2 pipeline operates at 100 percent of the pipeline's transport capacity. To ensure consistency in reporting between the Inventory and the Canadian National Greenhouse Gas Inventory, the amount of associated fossil fuel (lignite coal) that is gasified to create the exported CO_2 has been revised to align with the Canadian National Greenhouse Gas Inventory (Environment and Climate Change Canada 2020). These adjustments are explained in greater detail in Annex 2.1. This resulted in an average decrease of 0.7 MMT CO_2 Eq. (10 percent) in the amount of CO_2 exported each year between 2000 and 2018 and therefore an increase in coal use across the time series.

All of the revisions discussed above resulted in the following impacts on emissions over time by fuel type:

- Coal emissions increased by an average annual amount of 2.8 MMT CO_2 Eq. (0.2 percent increase of emissions from coal) across the entire time series. This is primarily due to the update to the adjustment for COG and BFG and the change in CO_2 export data.
- There was a slight average annual increase in natural gas emissions from 1990 to 2006 of 0.2 MMT CO_2 Eq. (less than 0.1 percent of natural gas emissions). This is mainly due to the removal of the COG and BFG adjustment from industrial natural gas consumption. There was a bigger average annual decrease in emissions of 5.0 MMT CO_2 Eq. (0.3 percent) from 2007 to 2018. The decrease is much larger in the latter years due to the update of the 2018 MECS data, which increases natural gas use as NEU in the industrial sector.
- Petroleum emissions decreased by an average annual amount of 15.3 MMT CO_2 Eq. (0.7 percent of petroleum emissions) from 1990 to 1999, which is mainly due to decreased emissions in the industrial sector as a result of the update in the weighted industrial HGL C contents and the decrease in petroleum use from the updated data for U.S. Territories.
- Petroleum emissions increased by an average annual amount of 14.5 MMT CO_2 Eq. (0.6 percent) from 2000 to 2007. This is mainly due to an increase in petroleum emissions in U.S. Territories from the newly integrated data and increased emissions in the Transportation sector due to changes in accounting for denaturants and updates in the distillate fuel oil and motor gasoline emissions factors.
- Finally, petroleum emissions decreased at the end of the time series by an average annual amount of 15.8 MMT CO_2 Eq. (0.7 percent) from 2008 to 2018. This is mainly due to the decrease in petroleum use from the newly integrated data for U.S. Territories and decreases across the other sectors based on updated gasoline and diesel fuel emission factors.

Overall, these changes resulted in an average annual decrease of 6.4 MMT CO_2 Eq. (0.1 percent) in CO_2 emissions from fossil fuel combustion for the period 1990 through 2018, relative to the previous Inventory. However, there were bigger absolute changes across the time series as discussed above by fuel type. The changes in petroleum emissions drive the overall change in emissions from the recalculations across time.

Planned Improvements

To reduce uncertainty of CO_2 from fossil fuel combustion estimates for U.S. Territories, further expert elicitation may be conducted to better quantify the total uncertainty associated with emissions from U.S. Territories.

The availability of facility-level combustion emissions through EPA's GHGRP will continue to be examined to help better characterize the industrial sector's energy consumption in the United States and further classify total industrial sector fossil fuel combustion emissions by business establishments according to industrial economic activity type. Most methodologies used in EPA's GHGRP are consistent with IPCC methodologies, though for EPA's GHGRP, facilities collect detailed information specific to their operations according to detailed measurement standards, which may differ with the more aggregated data collected for the Inventory to estimate total, national U.S. emissions. In addition, and unlike the reporting requirements for this chapter under the UNFCCC reporting guidelines, some facility-level fuel combustion emissions reported under the GHGRP may also include industrial process emissions.[49] In line with UNFCCC reporting guidelines, fuel combustion emissions are included in this chapter, while process emissions are included in the Industrial Processes and Product Use chapter of this report. In examining data from EPA's GHGRP that would be useful to improve the emission estimates for the CO_2 from fossil fuel combustion category, particular attention will also be made to ensure time-series consistency, as the facility-level reporting data from EPA's GHGRP are not available for all inventory years as reported in this Inventory.

Additional analyses will be conducted to align reported facility-level fuel types and IPCC fuel types per the national energy statistics. For example, efforts will be taken to incorporate updated industrial fuel consumption data from EIA's Manufacturing Energy Consumption Survey (MECS), with updated data for 2018. Additional work will look at CO_2 emissions from biomass to ensure they are separated in the facility-level reported data and maintaining consistency with national energy statistics provided by EIA. In implementing improvements and integration of data

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

from EPA's GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will continue to be relied upon.[50]

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

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

CH_4 and N_2O from Stationary Combustion

Methodology

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

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

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

National coal, natural gas, fuel oil, and wood consumption data were grouped by sector: industrial, commercial, residential, and U.S. Territories. For the CH_4 and N_2O emission estimates, consumption data for each fuel were obtained from EIA's *Monthly Energy Review* (EIA 2020a). Because the United States does not include territories in its national energy statistics, fuel consumption data for territories were provided separately by EIA's International Energy Statistics (EIA 2020b).[51] Fuel consumption for the industrial sector was adjusted to subtract out mobile source construction and agricultural use, which is reported under mobile sources. Construction and agricultural mobile source fuel use was obtained from EPA (2019) and FHWA (1996 through 2019). Estimates for wood biomass consumption for fuel combustion do not include municipal solid waste, tires, etc., that are reported as biomass by EIA. Non-CO_2 emissions from combustion of the biogenic portion of municipal solid waste and tires is included under waste incineration (Section 3.2). Estimates for natural gas combustion do not include biogas, and therefore non-CO_2 emissions from biogas are not included (see the Planned Improvements section, below). Tier 1 default emission factors for the industrial, commercial, and residential end-use sectors were provided by the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC 2006). U.S. Territories' emission factors were estimated using the U.S. emission factors for the primary sector in which each fuel was combusted.

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

[51] U.S. Territories data also include combustion from mobile activities because data to allocate territories' energy use were unavailable. For this reason, CH_4 and N_2O emissions from combustion by U.S. Territories are only included in the stationary combustion totals.

Electric Power Sector

The electric power sector uses a Tier 2 emission estimation methodology as fuel consumption for the electric power sector by control-technology type was based on EPA's Acid Rain Program Dataset (EPA 2021). Total fuel consumption in the electric power sector from EIA (2020a) was apportioned to each combustion technology type and fuel combination using a ratio of fuel consumption by technology type derived from EPA (2020a) data. The combustion technology and fuel use data by facility obtained from EPA (2020a) were only available from 1996 to 2019, so the consumption estimates from 1990 to 1995 were estimated by applying the 1996 consumption ratio by combustion technology type from EPA (2020a) to the total EIA (2020a) consumption for each year from 1990 to 1995.

Emissions were estimated by multiplying fossil fuel and wood consumption by technology-, fuel-, and country-specific Tier 2 emission factors. The Tier 2 emission factors used are based in part on emission factors published by EPA, and EPA's Compilation of Air Pollutant Emission Factors, AP-42 (EPA 1997) for coal wall-fired boilers, residual fuel oil, diesel oil and wood boilers, natural gas-fired turbines, and combined cycle natural gas units.[52]

Uncertainty and Time-Series Consistency

Methane emission estimates from stationary sources exhibit high uncertainty, primarily due to difficulties in calculating emissions from wood combustion (i.e., fireplaces and wood stoves). The estimates of CH_4 and N_2O emissions presented are based on broad indicators of emissions (i.e., fuel use multiplied by an aggregate emission factor for different sectors), rather than specific emission processes (i.e., by combustion technology and type of emission control).

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

The uncertainty estimation model for this source category was developed by integrating the CH_4 and N_2O stationary source inventory estimation models with the model for CO_2 from fossil fuel combustion to realistically characterize the interaction (or endogenous correlation) between the variables of these three models. About 55 input variables were simulated for the uncertainty analysis of this source category (about 20 from the CO_2 emissions from fossil fuel combustion inventory estimation model and about 35 from the stationary source inventory models).

In developing the uncertainty estimation model, uniform distribution was assumed for all activity-related input variables and N_2O emission factors, based on the SAIC/EIA (2001) report.[53] For these variables, the uncertainty ranges were assigned to the input variables based on the data reported in SAIC/EIA (2001).[54] However, the CH_4 emission factors differ from those used by EIA. These factors and uncertainty ranges are based on IPCC default uncertainty estimates (IPCC 2006).

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-18. Stationary combustion CH_4 emissions in 2019 (including biomass) were estimated to be between 5.5 and 20.2 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 36 percent below to 133 percent above the 2019 emission

[52] Several of the U.S. Tier 2 emission factors were used in IPCC (2006) as Tier 1 emission factors. See Table A-75 in Annex 3.1 for emission factors by technology type and fuel type for the electric power sector.

[53] 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.

[54] 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.

estimate of 8.7 MMT CO_2 Eq.[55] Stationary combustion N_2O emissions in 2019 (including biomass) were estimated to be between 18.7 and 37.7 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 25 percent below to 51 percent above the 2019 emission estimate of 24.9 MMT CO_2 Eq.

Table 3-18: Approach 2 Quantitative Uncertainty Estimates for CH_4 and N_2O Emissions from Energy-Related Stationary Combustion, Including Biomass (MMT CO_2 Eq. and Percent)

Source	Gas	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	8.7	5.5	20.2	-36%	+133%
Stationary Combustion	N_2O	24.9	18.7	37.7	-25%	+51%

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

The uncertainties associated with the emission estimates of CH_4 and N_2O are greater than those associated with estimates of CO_2 from fossil fuel combustion, which mainly rely on the carbon content of the fuel combusted. Uncertainties in both CH_4 and N_2O estimates are due to the fact that emissions are estimated based on emission factors representing only a limited subset of combustion conditions. For the indirect greenhouse gases, uncertainties are partly due to assumptions concerning combustion technology types, age of equipment, emission factors used, and activity data projections.

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990 through 2019 as discussed below. Details on the emission trends through time are described in more detail in the Methodology section, above. As discussed in Annex 5, data are unavailable to include estimates of CH_4 and N_2O emissions from biomass use in Territories, but those emissions are assumed to be insignificant.

QA/QC and Verification

In order to ensure the quality of the non-CO_2 emission estimates from stationary combustion, general (IPCC Tier 1) and category-specific (Tier 2) Quality Assurance/Quality Control (QA/QC) procedures were implemented consistent with the U.S. Inventory QA/QC plan outlined in Annex 8. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and emission factor sources and methodology used for estimating CH_4, N_2O, and the greenhouse gas precursors from stationary combustion in the United States. Emission totals for the different sectors and fuels were compared and trends were investigated.

Recalculations Discussion

Methane and N_2O emissions from stationary sources (excluding CO_2) across the entire time series were revised due to revised data from EIA (2020a) and EPA (2020a) relative to the previous Inventory. Most notably, newly published U.S. Territories data from EIA (2020b) was integrated, which impacted coal, fuel oil, and natural gas estimates for U.S. Territories across the time series. EIA (2020a) revised approximate heat rates for electricity and the heat content of electricity for natural gas and noncombustible renewable energy, which impacted electric power energy consumption by sector. As a result of revised natural gas heat contents, EIA updated natural gas consumption in the residential, commercial, and industrial sectors for 2018.

EIA also revised sector allocations for distillate fuel oil, residual fuel oil, and kerosene for 2018, and for propane for 2010 through 2012, 2014, 2017, and 2018, which impacted LPG by sector. EPA (2020a) revised coal, fuel oil, natural gas, and wood consumption statistics for 2018 in the electric power sector. EPA revised distillate fuel oil

[55] 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.

carbon contents and LPG heat contents and carbon contents, which affect petroleum consumption in the residential, commercial, and industrial sectors (EPA 2020; ICF 2020). The historical data changes and methodology updates resulted in an average annual decrease of less than 0.05 MMT CO_2 Eq. (0.2 percent) in CH_4 emissions, and an average annual decrease of less than 0.05 MMT CO_2 Eq. (0.1 percent) in N_2O emissions for the 1990 through 2018 period.

Planned Improvements

Several items are being evaluated to improve the CH_4 and N_2O emission estimates from stationary combustion and to reduce uncertainty for U.S. Territories. Efforts will be taken to work with EIA and other agencies to improve the quality of the U.S. Territories data. Because these data are not broken out by stationary and mobile uses, further research will be aimed at trying to allocate consumption appropriately. In addition, the uncertainty of biomass emissions will be further investigated because it was expected that the exclusion of biomass from the estimates would reduce the uncertainty; and in actuality the exclusion of biomass increases the uncertainty. These improvements are not all-inclusive but are part of an ongoing analysis and efforts to continually improve these stationary combustion estimates from U.S. Territories.

Other forms of biomass-based gas consumption include biogas. EPA will examine EIA and GHGRP data on biogas collected and burned for energy use and determine if CH_4 and N_2O emissions from biogas can be included in future inventories. EIA (2020a) natural gas data already deducts biogas used in the natural gas supply, so no adjustments are needed to the natural gas fuel consumption data to account for biogas.

CH_4 and N_2O from Mobile Combustion

Methodology

Estimates of CH_4 and N_2O emissions from mobile combustion were calculated by multiplying emission factors by measures of activity for each fuel and vehicle type (e.g., light-duty gasoline trucks). Activity data included vehicle miles traveled (VMT) for on-road vehicles and fuel consumption for non-road mobile sources. The activity data and emission factors used in the calculations are described in the subsections that follow. A complete discussion of the methodology used to estimate CH_4 and N_2O emissions from mobile combustion and the emission factors used in the calculations is provided in Annex 3.2.

On-Road Vehicles

Estimates of CH_4 and N_2O emissions from gasoline and diesel on-road vehicles are based on VMT and emission factors (in grams of CH_4 and N_2O per mile) by vehicle type, fuel type, model year, and emission control technology. Emission estimates for alternative fuel vehicles (AFVs) are based on VMT and emission factors (in grams of CH_4 and N_2O per mile) by vehicle and fuel type.[56]

CH_4 and N_2O emissions factors for newer (starting with model year 2004) on-road gasoline vehicles were calculated by Browning (2019) from annual vehicle certification data compiled by EPA. CH_4 and N_2O emissions factors for older (model year 2003 and earlier) on-road gasoline vehicles were developed by ICF (2004). These emission factors were derived from EPA, California Air Resources Board (CARB) and Environment and Climate Change Canada laboratory test results of different vehicle and control technology types. The EPA, CARB and Environment and Climate Change Canada tests were designed following the Federal Test Procedure (FTP). The procedure covers three separate driving segments, since vehicles emit varying amounts of greenhouse gases depending on the driving segment. These driving segments are: (1) a transient driving cycle that includes cold start and running emissions, (2) a cycle that represents running emissions only, and (3) a transient driving cycle that includes hot

[56] 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.

start and running emissions. For each test run, a bag was affixed to the tailpipe of the vehicle and the exhaust was collected; the content of this bag was then analyzed to determine quantities of gases present. The emissions characteristics of driving segment 2 tests were used to define running emissions. Running emissions were subtracted from the total FTP emissions to determine start emissions. These were then recombined to approximate average driving characteristics, based upon the ratio of start to running emissions for each vehicle class from MOBILE6.2, an EPA emission factor model that predicts gram per mile emissions of CO_2, CO, HC, NO_x, and PM from vehicles under various conditions.[57]

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

CH_4 and N_2O emission factors for AFVs were developed based on the 2019 Greenhouse gases, Regulated Emissions, and Energy use in Transportation (GREET) model (ANL 2020). For light-duty trucks, EPA used a curve fit of 1999 through 2011 travel fractions for LDT1 and LDT2 (MOVES Source Type 31 for LDT1 and MOVES Source Type 32 for LDT2). For medium-duty vehicles, EPA used emission factors for light heavy-duty vocational trucks. For heavy-duty vehicles, EPA used emission factors for long-haul combination trucks. For buses, EPA used emission factors for transit buses. These values represent vehicle operations only (tank-to-wheels); upstream well-to-tank emissions are calculated elsewhere in the Inventory. Biodiesel CH_4 emission factors were corrected from GREET values to be the same as CH_4 emission factors for diesel vehicles. GREET overestimated biodiesel CH_4 emission factors based upon an incorrect CH_4-to-THC ratio for diesel vehicles with aftertreatment technology.

Annual VMT data for 1990 through 2019 were obtained from the Federal Highway Administration's (FHWA) Highway Performance Monitoring System database as reported in Highway Statistics (FHWA 1996 through 2019).[58] VMT estimates were then allocated from FHWA's vehicle categories to fuel-specific vehicle categories using the calculated shares of vehicle fuel use for each vehicle category by fuel type reported in DOE (1993 through 2018) and information on total motor vehicle fuel consumption by fuel type from FHWA (1996 through 2019). VMT for AFVs were estimated based on Browning (2017 and 2018a). The age distributions of the U.S. vehicle fleet were obtained from EPA (2019a, 2000), and the average annual age-specific vehicle mileage accumulation of U.S. vehicles were obtained from EPA (2019a).

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

Non-Road Mobile Sources

The non-road mobile category for CH_4 and N_2O includes ships and boats, aircraft, locomotives and off-road sources (e.g., construction or agricultural equipment). For non-road sources, fuel-based emission factors are applied to data on fuel consumption, following the IPCC Tier 1 approach, for locomotives, aircraft, ships and boats. The Tier 2 approach would require separate fuel-based emissions factors by technology for which data are not available. For

[57] 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>.

[58] 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.

some of the non-road categories, 2-stroke and 4-stroke technologies are broken out and have separate emission factors; those cases could be considered a Tier 2 approach.

To estimate CH_4 and N_2O emissions from non-road mobile sources, fuel consumption data were employed as a measure of activity, and multiplied by fuel-specific emission factors (in grams of N_2O and CH_4 per kilogram of fuel consumed).[59] Activity data were obtained from AAR (2008 through 2019), APTA (2007 through 2019), RailInc (2014 through 2019), APTA (2006), BEA (1991 through 2015), Benson (2002 through 2004), DLA Energy (2020), DOC (1991 through 2019), DOE (1993 through 2018), DOT (1991 through 2019), EIA (2002, 2007, 2020a), EIA (2020f), EIA (1991 through 2019), EPA (2019a), Esser (2003 through 2004), FAA (2021), FHWA (1996 through 2019),[60] Gaffney (2007), and Whorton (2006 through 2014). Emission factors for non-road modes were taken from IPCC (2006) and Browning (2020 and 2018b).

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis was conducted for the mobile source sector using the IPCC-recommended Approach 2 uncertainty estimation methodology, Monte Carlo Stochastic Simulation technique, using @RISK software. The uncertainty analysis was performed on 2019 estimates of CH_4 and N_2O emissions, incorporating probability distribution functions associated with the major input variables. For the purposes of this analysis, the uncertainty was modeled for the following four major sets of input variables: (1) VMT data, by on-road vehicle and fuel type, (2) emission factor data, by on-road vehicle, fuel, and control technology type, (3) fuel consumption, data, by non-road vehicle and equipment type, and (4) emission factor data, by non-road vehicle and equipment type.

Uncertainty analyses were not conducted for NO_x, CO, or NMVOC emissions. Emission factors for these gases have been extensively researched because emissions of these gases from motor vehicles are regulated in the United States, and the uncertainty in these emission estimates is believed to be relatively low. For more information, see Section 3.9 – Uncertainty Analysis of Emission Estimates. However, a much higher level of uncertainty is associated with CH_4 and N_2O emission factors due to limited emission test data, and because, unlike CO_2 emissions, the emission pathways of CH_4 and N_2O are highly complex.

Based on the uncertainty analysis, mobile combustion CH_4 emissions from all mobile sources in 2019 were estimated to be between 2.3 and 3.5 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 2 percent below to 46 percent above the corresponding 2019 emission estimate of 2.4 MMT CO_2 Eq. Mobile combustion N_2O emissions from mobile sources in 2019 were estimated to be between 16.4 and 21.3 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 9 percent below to 19 percent above the corresponding 2019 emission estimate of 18.0 MMT CO_2 Eq.

[59] 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.

[60] This Inventory uses FHWA's Agriculture, Construction, and Commercial/Industrial MF-24 fuel volumes along with the MOVES model gasoline volumes to estimate non-road mobile source CH_4 and N_20 emissions for these categories. For agriculture, the MF-24 gasoline volume is used directly because it includes both 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.

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

Source	Gas	2019 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	2.4	2.3	3.5	-2%	+46%
Mobile Sources	N_2O	18.0	16.4	21.3	-9%	+19%

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

This uncertainty analysis is a continuation of a multi-year process for developing quantitative uncertainty estimates for this source category using the IPCC Approach 2 uncertainty estimation methodology. As a result, as new information becomes available, uncertainty characterization of input variables may be improved and revised. For additional information regarding uncertainty in emission estimates for CH_4 and N_2O please refer to the Uncertainty Annex. As discussed in Annex 5, data are unavailable to include estimates of CH_4 and N_2O emissions from any liquid fuel used in pipeline transport or some biomass used in transportation sources, but those emissions are assumed to be insignificant.

QA/QC and Verification

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

Recalculations Discussion

Updates were made to CH_4 and N_2O emission factors for newer non-road gasoline and diesel vehicles. Previously, these emission factors were calculated using the updated 2006 IPCC Tier 3 guidance and the nonroad component EPA's MOVES2014b model. CH_4 emission factors were calculated directly from MOVES. N_2O emission factors were calculated using MOVES-Nonroad activity and emission factors in g/kWh by fuel type from the European Environment Agency. Updated emission factors were developed this year using EPA engine certification data for non-road small and large spark-ignition (SI) gasoline engines and compression-ignition diesel engines (model year 2011 and newer), as well as non-road motorcycles (model year 2006 and newer), SI marine engines (model year 2011 and newer), and diesel marine engines (model year 2000 and newer).

The collective result of these changes was a net decrease in CH_4 emissions and an increase in N_2O emissions from mobile combustion relative to the previous Inventory. Methane emissions decreased by 23.2 percent. Nitrous oxide emissions increased by 23.6 percent.

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990 through 2019 with one recent notable exception. An update by FHWA to the method for estimating on-road VMT created an inconsistency in on-road CH_4 and N_2O for the time periods 1990 to 2006 and 2007 to 2019. Details on the emission trends and methodological inconsistencies through time are described in the Methodology section above.

Planned Improvements

While the data used for this report represent the most accurate information available, several areas for improvement have been identified.

- Update emission factors for motorcycles. The Inventory does not currently account for advanced technology motorcycles. EPA certification data can be used to update motorcycle assumptions to better capture the portion of the motorcycle fleet using advanced emissions controls.
- Update emission factors for buses. The Inventory currently groups buses into the heavy-duty vehicle category. New emission factors specific to buses can be developed from EPA certification data.
- Update emission factors for ships and boats using residual fuel and distillate fuel, emission factors for locomotives using ultra low sulfur diesel, and emission factors for aircraft using jet fuel. The Inventory is currently using IPCC default values for these emissions factors.
- Continue to explore potential improvements to estimates of domestic waterborne fuel consumption for future Inventories. The Inventory estimates for residual and distillate fuel used by ships and boats is based in part on data on bunker fuel use from the U.S. Department of Commerce. Domestic fuel consumption is estimated by subtracting fuel sold for international use from the total sold in the United States. Since 2015, all ships travelling within 200 nautical miles of the US coastlines must use distillate fuels thereby overestimating the residual fuel used by US vessels and underestimating distillate fuel use in these ships.

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

In addition to being combusted for energy, fossil fuels are also consumed for non-energy uses (NEU) in the United States. The fuels used for these purposes are diverse, including natural gas, hydrocarbon gas liquids (HGL),[61] asphalt (a viscous liquid mixture of heavy crude oil distillates), petroleum coke (manufactured from heavy oil), and coal (metallurgical) coke (manufactured from coking coal). The non-energy applications of these fuels are equally diverse, including feedstocks for the manufacture of plastics, rubber, synthetic fibers and other materials; reducing agents for the production of various metals and inorganic products; and products such as lubricants, waxes, and asphalt (IPCC 2006). Emissions from non-energy use of lubricants, paraffin waxes, bitumen / asphalt, and solvents are reported in the Energy sector, as opposed to the Industrial Processes and Product Use (IPPU) sector, to reflect national circumstances in its choice of methodology and to increase transparency of this source category's unique country-specific data sources and methodology (see Box 3-5). In addition, estimates of non-energy use emissions included here do not include emissions already reflected in the IPPU sector, e.g., fuels used as reducing agents. To avoid double counting, the "raw" non-energy fuel consumption data reported by EIA are reduced to account for these emissions already included under IPPU.

Carbon dioxide emissions arise from non-energy uses via several pathways. Emissions may occur during the manufacture of a product, as is the case in producing plastics or rubber from fuel-derived feedstocks. Additionally, emissions may occur during the product's lifetime, such as during solvent use. Overall, throughout the time series

[61] 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.

and across all uses, about 62 percent of the total C consumed for non-energy purposes was stored in products (e.g., plastics), and not released to the atmosphere; the remaining 38 percent was emitted.

There are several areas in which non-energy uses of fossil fuels are closely related to other parts of this Inventory. For example, some of the non-energy use products release CO_2 at the end of their commercial life when they are combusted after disposal; these emissions are reported separately within the Energy chapter in the Incineration of Waste source category. There are also net exports of petrochemical intermediate products that are not completely accounted for in the EIA data, and the Inventory calculations adjust for the effect of net exports on the mass of C in non-energy applications.

As shown in Table 3-20, fossil fuel emissions in 2019 from the non-energy uses of fossil fuels were 128.8 MMT CO_2 Eq., which constituted approximately 2 percent of overall fossil fuel emissions. In 2019, the consumption of fuels for non-energy uses (after the adjustments described above) was 5,635.0 TBtu (see Table 3-21). A portion of the C in the 5,635.0 TBtu of fuels was stored (228.8 MMT CO_2 Eq.), while the remaining portion was emitted (128.8 MMT CO_2 Eq.). Non-energy use emissions decreased by 0.7 percent from 2018 to 2019 mainly due to a decrease in the ratio between C stored and potential emissions. See Annex 2.3 for more details.

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

Year	1990		2005		2015	2016	2017	2018	2019
Potential Emissions	306.1		367.4		322.8	317.8	332.7	352.8	357.5
C Stored	193.3		238.3		214.4	218.0	219.2	223.1	228.8
Emissions as a % of Potential	37%		35%		34%	31%	34%	37%	36%
C Emitted	**112.8**		**129.1**		**108.5**	**99.8**	**113.5**	**129.7**	**128.8**

Methodology

The first step in estimating C stored in products was to determine the aggregate quantity of fossil fuels consumed for non-energy uses. The C content of these feedstock fuels is equivalent to potential emissions, or the product of consumption and the fuel-specific C content values. Both the non-energy fuel consumption and C content data were supplied by the EIA (2020) (see Annex 2.1). Consumption values for industrial coking coal, petroleum coke, other oils, and natural gas in Table 3-21 and Table 3-22 have been adjusted to subtract non-energy uses that are included in the source categories of the Industrial Processes and Product Use chapter.[62] Consumption of natural gas, HGL, pentanes plus, naphthas, other oils, and special naphtha were adjusted to subtract out net exports of these products that are not reflected in the raw data from EIA. Consumption values were also adjusted to subtract net exports of HGL components (e.g., propylene, ethane).

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

- For several fuel types—petrochemical feedstocks (including natural gas for non-fertilizer uses, HGL, pentanes plus, naphthas, other oils, still gas, special naphtha, and industrial other coal), asphalt and road oil, lubricants, and waxes—U.S. data on C stocks and flows were used to develop C storage factors, calculated as the ratio of (a) the C stored by the fuel's non-energy products to (b) the total C content of the fuel consumed. A lifecycle approach was used in the development of these factors in order to account for losses in the production process and during use. Because losses associated with municipal solid waste management are handled separately in the Energy sector under the Incineration of Waste source category, the storage factors do not account for losses at the disposal end of the life cycle.

[62] 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.

- For industrial coking coal and distillate fuel oil, storage factors were taken from Marland and Rotty (1984).
- For the remaining fuel types (petroleum coke, miscellaneous products, and other petroleum), IPCC (2006) does not provide guidance on storage factors, and assumptions were made based on the potential fate of C in the respective non-energy use products. Carbon dioxide emissions from carbide production are implicitly accounted for in the storage factor calculation for the non-energy use of petroleum coke.

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

Year	1990	2005	2015	2016	2017	2018	2019
Industry	**4,317.2**	**5,111.1**	**4,864.5**	**4,833.1**	**5,089.6**	**5,445.4**	**5,492.3**
Industrial Coking Coal	NO	80.4	122.4	89.6	113.0	124.8	132.1
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	418.9	496.4	588.0	675.9	664.6
Asphalt & Road Oil	1,170.2	1,323.2	831.7	853.4	849.2	792.8	843.9
HGL	1,218.4	1,610.4	2,160.2	2,128.0	2,193.5	2,505.1	2,545.1
Lubricants	186.3	160.2	142.1	135.1	124.9	121.9	117.6
Pentanes Plus	117.5	95.4	78.3	53.1	81.7	105.2	154.7
Naphtha (<401 °F)	327.0	679.5	418.1	398.2	413.0	421.0	368.8
Other Oil (>401 °F)	663.6	499.5	216.9	204.6	242.9	219.0	211.7
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	97.1	89.0	95.3	87.0	89.3
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**	**5,037.7**	**4,998.0**	**5,242.3**	**5,593.0**	**5,635.0**

NO (Not Occurring)

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

Sector/Fuel Type	Adjusted Non-Energy Use[a] (TBtu)	Carbon Content Coefficient (MMT C/QBtu)	Potential Carbon (MMT C)	Storage Factor	Carbon Stored (MMT C)	Carbon Emissions (MMT C)	Carbon Emissions (MMT CO_2 Eq.)
Industry	**5,492.3**	**NA**	**94.6**	**NA**	**62.1**	**32.5**	**119.2**
Industrial Coking Coal	132.1	25.59	3.4	0.10	0.3	3.0	11.2
Industrial Other Coal	9.5	26.07	0.2	0.62	0.2	0.1	0.3
Natural Gas to Chemical Plants	664.6	14.47	9.6	0.62	5.9	3.6	13.4
Asphalt & Road Oil	843.9	20.55	17.3	1.00	17.3	0.1	0.3
HGL	2,545.1	16.85	42.9	0.62	26.6	16.3	59.8
Lubricants	117.6	20.20	2.4	0.09	0.2	2.2	7.9
Pentanes Plus	154.7	18.24	2.8	0.62	1.7	1.1	3.9
Naphtha (<401° F)	368.8	18.55	6.8	0.62	4.2	2.6	9.5
Other Oil (>401° F)	211.7	20.17	4.3	0.62	2.6	1.6	6.0
Still Gas	158.7	17.51	2.8	0.62	1.7	1.1	3.9
Petroleum Coke	NO	27.85	NO	0.30	NO	NO	NO

Special Naphtha	89.3	19.74	1.8	0.62	1.1	0.7	2.5
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**	**+**	**0.2**	**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	**5,635.0**		**97.5**		**62.4**	**35.1**	**128.8**

Note: Totals may not sum due to independent rounding.
+ Does not exceed 0.05 TBtu, MMT C, or MMT CO_2 Eq.
NA (Not Applicable)
NO (Not Occurring)
[a] To avoid double counting, net exports have been deducted.

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

Where storage factors were calculated specifically for the United States, data were obtained on (1) products such as asphalt, plastics, synthetic rubber, synthetic fibers, cleansers (soaps and detergents), pesticides, food additives, antifreeze and deicers (glycols), and silicones; and (2) industrial releases including energy recovery (waste gas from chemicals), Toxics Release Inventory (TRI) releases, hazardous waste incineration, and volatile organic compound, solvent, and non-combustion CO emissions. Data were taken from a variety of industry sources, government reports, and expert communications. Sources include EPA reports and databases such as compilations of air emission factors (EPA 2001), *National Emissions Inventory (NEI) Air Pollutant Emissions Trends Data* (EPA 2020), *Toxics Release Inventory, 1998* (EPA 2000b), *Biennial Reporting System* (EPA 2000a, 2009), *Resource Conservation and Recovery Act Information System* (EPA 2013b, 2015, 2016b, 2018b, 2021), pesticide sales and use estimates (EPA 1998, 1999, 2002, 2004, 2011, 2017), and the Chemical Data Access Tool (EPA 2014b); the EIA Manufacturer's Energy Consumption Survey (MECS) (EIA 1994, 1997, 2001, 2005, 2010, 2013, 2017, 2021); the National Petrochemical & Refiners Association (NPRA 2002); the U.S. Census Bureau (1999, 2004, 2009, 2014); Bank of Canada (2012, 2013, 2014, 2016, 2017, 2018, 2019, 2020); Financial Planning Association (2006); INEGI (2006); the United States International Trade Commission (1990 through 2018); Gosselin, Smith, and Hodge (1984); EPA's *Municipal Solid Waste (MSW) Facts and Figures* (EPA 2013, 2014a, 2016a, 2018a, 2019); the Rubber Manufacturers' Association (RMA 2009, 2011, 2014, 2016, 2018); the International Institute of Synthetic Rubber Products (IISRP 2000, 2003); the Fiber Economics Bureau (FEB 2001, 2003, 2005, 2007, 2009, 2010, 2011, 2012, 2013); the Independent Chemical Information Service (ICIS 2008, 2016); the EPA Chemical Data Access Tool (CDAT) (EPA 2014b); the American Chemistry Council (ACC 2003 through 2011, 2013, 2014, 2015, 2016, 2017, 2018, 2019, 2020b); and the *Guide to the Business of Chemistry* (ACC 2020a). Specific data sources are listed in full detail in Annex 2.3.

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.[63] 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

[63] 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).

Emitted from Non-Energy Uses of Fossil Fuels source category (CRF Source Category 1A5).[64]

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.[65] The country-specific methodology to reflect national circumstances starts with the aggregate amount of fossil fuels used for non-energy uses and applies a C balance calculation, breaking out the C emissions from non-energy use of lubricants, waxes, and asphalt and road oil. 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.

Uncertainty and Time-Series Consistency

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

As noted above, the non-energy use analysis is based on U.S.-specific storage factors for (1) feedstock materials (natural gas, HGL, pentanes plus, naphthas, other oils, still gas, special naphthas, and other industrial coal), (2)

[64] 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*.

[65] 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.

asphalt, (3) lubricants, and (4) waxes. For the remaining fuel types (the "other" category in Table 3-21 and Table 3-22), the storage factors were taken directly from IPCC (2006), where available, and otherwise assumptions were made based on the potential fate of carbon in the respective NEU products. To characterize uncertainty, five separate analyses were conducted, corresponding to each of the five categories. In all cases, statistical analyses or expert judgments of uncertainty were not available directly from the information sources for all the activity variables; thus, uncertainty estimates were determined using assumptions based on source category knowledge.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-23 (emissions) and Table 3-24 (storage factors). Carbon emitted from non-energy uses of fossil fuels in 2019 was estimated to be between 81.0 and 187.2 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 37 percent below to 45 percent above the 2019 emission estimate of 128.8 MMT CO_2 Eq. The uncertainty in the emission estimates is a function of uncertainty in both the quantity of fuel used for non-energy purposes and the storage factor.

Table 3-23: Approach 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Non-Energy Uses of Fossil Fuels (MMT CO_2 Eq. and Percent)

Source	Gas	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	99.3	56.4	160.4	-43%	+62%
Asphalt	CO_2	0.3	0.1	0.6	-58%	+118%
Lubricants	CO_2	16.9	14.0	19.6	-17%	+16%
Waxes	CO_2	0.3	0.2	0.6	-24%	+90%
Other	CO_2	12.0	2.5	13.9	-79%	+16%
Total	**CO_2**	**128.8**	**81.0**	**187.2**	**-37%**	**+45%**

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

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

Source	Gas	2019 Storage Factor (%)	Uncertainty Range Relative to Emission Estimate[a] (%)		(%, Relative)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Feedstocks	CO_2	62.0%	49.5%	72.8%	-20%	+18%
Asphalt	CO_2	99.6%	99.1%	99.8%	-0.5%	+0.2%
Lubricants	CO_2	9.2%	3.9%	17.5%	-58%	+91%
Waxes	CO_2	57.8%	47.5%	67.5%	-18%	+17%
Other	CO_2	11.3%	7.9%	81.0%	-30%	+618%

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

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

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

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

QA/QC and Verification

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

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

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

Recalculations Discussion

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

In addition, adjustments were made to activity data, carbon content coefficients, and heat contents for HGL for 1990 to 2018. Historical HGL activity data from 1990 to 2007 were adjusted to use EIA's Petroleum Supply Annual tables for consistency with the rest of the entire time series (i.e., 2008 to 2019). In previous Inventory reports, HGL activity data from 1990 to 2007 were extracted from the American Petroleum Institute's *Sales of Natural Gas Liquids and Liquefied Refinery Gases*. Thus, the HGL data source for the 1990 to 2007 portion of the time series was updated to align with the HGL activity data used for 2008 to 2019 as well as with data used in other Energy sector source categories (e.g., EIA's *Monthly Energy Review* (EIA 2020a)). In addition, the HGL carbon content coefficient for NEU was updated by separating each fuel out by its natural gas liquid (NGL)[66] and associated olefin to calculate a more accurate and annually variable factor, and the heat contents for HGL and pentanes plus were updated using updated data from EIA's *Monthly Energy Review* (EIA 2020a).

Natural Gas to Chemical Plants data were updated to reflect the 2018 MECS data. This resulted in an increase in natural gas used for NEU of 120 percent in 2018 compared to previous reports. Adjustments were also made to historical calculations to linearly interpolate between EIA's MECS data years. Previously, fuel consumption data for years between MECS releases were assumed to be equal to the previous year of data.

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

Overall, these changes resulted in an average annual decrease of 10.9 MMT CO_2 Eq. (8.7 percent) in carbon emissions from non-energy uses of fossil fuels for the period 1990 through 2018, relative to the previous Inventory. This decrease is primarily due to the removal of miscellaneous products, which previously constituted an average of 8.2 percent of total emissions from 1990 to 2018.

Planned Improvements

There are several future improvements planned:

- More accurate accounting of C in petrochemical feedstocks. EPA has worked with EIA to determine the cause of input/output discrepancies in the C mass balance contained within the NEU model. In the future, two strategies to reduce or eliminate this discrepancy will continue to be pursued as part of quality control procedures. First, accounting of C in imports and exports will be improved. The import/export adjustment methodology will be examined to ensure that net exports of intermediaries such as ethylene and propylene are fully accounted for. Second, the use of top-down C input calculation in estimating emissions will be reconsidered. Alternative approaches that rely more substantially on the bottom-up C output calculation will be considered instead.
- Improving the uncertainty analysis. Most of the input parameter distributions are based on professional judgment rather than rigorous statistical characterizations of uncertainty.
- Better characterizing flows of fossil C. Additional fates may be researched, including the fossil C load in organic chemical wastewaters, plasticizers, adhesives, films, paints, and coatings. There is also a need to further clarify the treatment of fuel additives and backflows (especially methyl tert-butyl ether, MTBE).
- Reviewing the trends in fossil fuel consumption for non-energy uses. Annual consumption for several fuel types is highly variable across the time series, including industrial coking coal and other petroleum. A better understanding of these trends will be pursued to identify any mischaracterized or misreported fuel consumption for non-energy uses.
- Updating the average C content of solvents was researched, since the entire time series depends on one year's worth of solvent composition data. The data on C emissions from solvents that were readily available do not provide composition data for all categories of solvent emissions and also have conflicting definitions for volatile organic compounds, the source of emissive C in solvents. Additional sources of solvents data will be investigated in order to update the C content assumptions.
- Updating the average C content of cleansers (soaps and detergents) was researched; although production and consumption data for cleansers are published every 5 years by the Census Bureau, the composition (C content) of cleansers has not been recently updated. Recently available composition data sources may facilitate updating the average C content for this category.
- Revising the methodology for consumption, production, and C content of plastics was researched;

[66] 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).

because of recent changes to the type of data publicly available for plastics, the NEU model for plastics applies data obtained from personal communications. Potential revisions to the plastics methodology to account for the recent changes in published data will be investigated.

- Although U.S.-specific storage factors have been developed for feedstocks, asphalt, lubricants, and waxes, default values from IPCC are still used for two of the non-energy fuel types (industrial coking coal, distillate oil), and broad assumptions are being used for miscellaneous products and other petroleum. Over the long term, there are plans to improve these storage factors by analyzing C fate similar to those described in Annex 2.3 or deferring to more updated default storage factors from IPCC where available.
- Reviewing the storage of carbon black across various sectors in the Inventory; in particular, the carbon black abraded and stored in tires.

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 2020; Goldstein and Madtes 2001; Kaufman et al. 2004; Simmons et al. 2006; van Haaren et al. 2010). In the context of this section, waste includes all municipal solid waste (MSW) as well as scrap tires. In the United States, incineration of MSW tends to occur at waste-to-energy facilities or industrial facilities where useful energy is recovered, and thus emissions from waste incineration are accounted for in the Energy chapter. Similarly, scrap tires are combusted for energy recovery in industrial and utility boilers, pulp and paper mills, and cement kilns. Incineration of waste results in conversion of the organic inputs to CO_2. According to the *2006 IPCC Guidelines*, when the CO_2 emitted is of fossil origin, it is counted as a net anthropogenic emission of CO_2 to the atmosphere. Thus, the emissions from waste incineration are calculated by estimating the quantity of waste combusted and the fraction of the waste that is C derived from fossil sources.

Most of the organic materials in MSW are of biogenic origin (e.g., paper, yard trimmings), and have their net C flows accounted for under the Land Use, Land-Use Change, and Forestry chapter. However, some components 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. Estimates on emissions from hazardous waste incineration can be found in Annex 2.3 and are accounted for as part of the C mass balance for non-energy uses of fossil fuels.

Approximately 20.8 million metric tons of MSW were incinerated in 2011 (van Haaren et al. 2010). Updated data were not available for 2012 through 2019 from this source so the data were proxied to the 2011 estimate. Carbon dioxide emissions from incineration of waste increased 42 percent since 1990, to an estimated 11.5 MMT CO_2 (11,471 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).

Waste incineration is also a source of CH_4 and N_2O emissions (De Soete 1993; IPCC 2006). Methane emissions from the incineration of waste were estimated to be less than 0.05 MMT CO_2 Eq. (less than 0.05 kt CH_4) in 2019 and have decreased by 11 percent since 1990. Nitrous oxide emissions from the incineration of waste were estimated to be 0.3 MMT CO_2 Eq. (1 kt N_2O) in 2019 and have decreased by 32 percent since 1990. This decrease is driven by the decrease in total MSW incinerated.

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

Gas/Waste Product	1990		2005		2015	2016	2017	2018	2019
CO_2	**8.1**		**12.7**		**11.5**	**11.5**	**11.5**	**11.5**	**11.5**
Plastics	5.7		7.2		6.3	6.4	6.5	6.6	6.6
Synthetic Rubber in Tires	0.3		1.6		1.4	1.4	1.3	1.3	1.2
Carbon Black in Tires	0.4		2.0		1.8	1.7	1.5	1.5	1.5
Synthetic Rubber in MSW	0.9		0.8		0.7	0.7	0.7	0.7	0.7
Synthetic Fibers	0.8		1.2		1.3	1.4	1.4	1.4	1.4
CH_4	+		+		+	+	+	+	+
N_2O	**0.5**		**0.4**		**0.3**	**0.3**	**0.3**	**0.3**	**0.3**
Total	**8.5**		**13.1**		**11.8**	**11.8**	**11.8**	**11.9**	**11.8**

+ Does not exceed 0.05 MMT CO_2 Eq.

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

Gas/Waste Product	1990		2005		2015	2016	2017	2018	2019
CO_2	**8,062**		**12,713**		**11,533**	**11,525**	**11,537**	**11,547**	**11,471**
Plastics	5,699		7,163		6,316	6,370	6,532	6,588	6,588
Synthetic Rubber in Tires	308		1,599		1,440	1,369	1,298	1,264	1,229
Carbon Black in Tires	385		1,958		1,755	1,670	1,585	1,544	1,503
Synthetic Rubber in MSW	854		766		703	717	731	739	739
Synthetic Fibers	816		1,227		1,319	1,399	1,392	1,412	1,410
CH_4	**+**		**+**		**+**	**+**	**+**	**+**	**+**
N_2O	**2**		**1**		**1**	**1**	**1**	**1**	**1**

+ Does not exceed 0.5 kt.

Methodology

Emissions of CO_2 from the incineration of waste include CO_2 generated by the incineration of plastics, synthetic fibers, and synthetic rubber in MSW, as well as the incineration of synthetic rubber and carbon black in scrap tires. The emission estimates are calculated for all four sources on a mass-basis based on the data available. These emissions were estimated by multiplying the mass of each material incinerated by the C content of the material and the fraction oxidized (98 percent). Plastics incinerated in MSW were categorized into seven plastic resin types, each material having a discrete C content. Similarly, synthetic rubber is categorized into three product types, and synthetic fibers were categorized into four product types, each having a discrete C content. Scrap tires contain several types of synthetic rubber, carbon black, and synthetic fibers. Each type of synthetic rubber has a discrete C content, and carbon black is 100 percent C. Emissions of CO_2 were calculated based on the amount of scrap tires used for fuel and the synthetic rubber and carbon black content of scrap tires. More detail on the methodology for calculating emissions from each of these waste incineration sources is provided in Annex 3.7.

For each of the methods used to calculate CO_2 emissions from the incineration of waste, data on the quantity of product combusted and the C content of the product are needed. For plastics, synthetic rubber, and synthetic fibers in MSW, the amount of specific materials discarded as MSW (i.e., the quantity generated minus the quantity recycled) was taken from *Municipal Solid Waste Generation, Recycling, and Disposal in the United States: Facts and Figures* (EPA 2000 through 2003, 2005 through 2014), and *Advancing Sustainable Materials Management: Facts and Figures: Assessing Trends in Material Generation, Recycling and Disposal in the United States* (EPA 2015; EPA 2016; EPA 2018a; EPA 2019; EPA 2020) and detailed unpublished backup data for some years not shown in the reports (Schneider 2007). For 2012 through 2019 data on total waste incinerated were assumed to equal to the 2011 value from Shin (2014). For synthetic rubber and carbon black in scrap tires, information was obtained biannually from U.S. Scrap Tire Management Summary for 2005 through 2019 data (RMA 2020). Average C contents for the "Other" plastics category and synthetic rubber in MSW were calculated from 1998 and 2002 production statistics; C content for 1990 through 1998 is based on the 1998 value; C content for 1999 through

2001 is the average of 1998 and 2002 values; and C content for 2002 through 2019 is based on the 2002 value. Carbon content for synthetic fibers was calculated from a weighted average of production statistics from 1990 through 2019. Information about scrap tire composition was taken from the Rubber Manufacturers' Association internet site (RMA 2012a). The mass of incinerated material is multiplied by its C content to calculate the total amount of carbon stored.

The assumption that 98 percent of organic C is oxidized (which applies to all waste incineration categories for CO_2 emissions) was reported in EPA's life cycle analysis of greenhouse gas emissions and sinks from management of solid waste (EPA 2006). This percentage is multiplied by the carbon stored to estimate the amount of carbon emitted.

Incineration of waste, including MSW, also results in emissions of CH_4 and N_2O. These emissions were calculated as a function of the total estimated mass of waste incinerated and emission factors. As noted above, CH_4 and N_2O emissions are a function of total waste incinerated in each year; for 1990 through 2008, these data were derived from the information published in *BioCycle* (van Haaren et al. 2010). Data for 2009 and 2010 were interpolated between 2008 and 2011 values. Data for 2011 were derived from Shin (2014). Data on total waste incinerated was not available in the *BioCycle* data set for 2012 through 2019, so these values were assumed to equal the 2011 *BioCycle* dataset value.

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

Table 3-27: Municipal Solid Waste Generation (Metric Tons) and Percent Combusted (BioCycle dataset)

Year	Waste Discarded	Waste Incinerated	Incinerated (% of Discards)
1990	235,733,657	30,632,057	13.0%
2005	259,559,787	25,973,520	10.0%
2015	273,116,704[a]	20,756,870	7.6%
2016	273,116,704[a]	20,756,870	7.6%
2017	273,116,704[a]	20,756,870	7.6%
2018	273,116,704[a]	20,756,870	7.6%
2019	273,116,704[a]	20,756,870	7.6%

[a] Assumed equal to 2011 value.

Source: van Haaren et al. (2010), Shin (2014).

Uncertainty and Time-Series Consistency

An Approach 2 Monte Carlo analysis was performed to determine the level of uncertainty surrounding the estimates of CO_2 emissions and N_2O emissions from the incineration of waste (given the very low emissions for CH_4, no uncertainty estimate was derived). IPCC Approach 2 analysis allows the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the Inventory estimate. Uncertainty estimates and distributions for waste generation variables (i.e., plastics, synthetic rubber, and textiles generation) were obtained through a conversation with one of the authors of the Municipal Solid Waste in the United States reports. Statistical analyses or expert judgments of uncertainty were not available directly from the information sources for the other variables; thus, uncertainty estimates for these variables were determined using assumptions based on source category knowledge and the known uncertainty estimates for the waste generation variables.

The uncertainties in the waste incineration emission estimates arise from both the assumptions applied to the data and from the quality of the data. Key factors include MSW incineration rate; fraction oxidized; missing data on waste composition; average C content of waste components; assumptions on the synthetic/biogenic C ratio; and combustion conditions affecting N_2O emissions. The highest levels of uncertainty surround the variables that are based on assumptions (e.g., percent of clothing and footwear composed of synthetic rubber); the lowest levels of uncertainty surround variables that were determined by quantitative measurements (e.g., combustion efficiency, C content of C black).

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-28. Waste incineration CO_2 emissions in 2019 were estimated to be between 8.6 and 14.5 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 25 percent below to 27 percent above the 2019 emission estimate of 11.5 MMT CO_2 Eq. Also at a 95 percent confidence level, waste incineration N_2O emissions in 2019 were estimated to be between 0.2 and 1.3 MMT CO_2 Eq. This indicates a range of 50 percent below to 325 percent above the 2019 emission estimate of 0.3 MMT CO_2 Eq.

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

Source	Gas	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
Incineration of Waste	CO_2	11.5	8.6	14.5	-25%	27%
Incineration of Waste	N_2O	0.3	0.2	1.3	-50%	325%

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

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

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

Planned Improvements

The waste incineration estimates have recently relied on MSW mass flow (i.e., tonnage) data that has not been updated since 2011. These values come from *BioCycle* (Shin 2014) and *EPA Facts and Figures* (EPA 2015). EPA performed an examination of facility-level MSW tonnage data availability, primarily focusing on EPA's GHGRP data, Energy Information Administration (EIA) waste-to-energy data, and other sources. EPA concluded that the MSW mass flow of waste incinerated can be derived from GHGRP data and that the GHGRP dataset is the most complete dataset (i.e., includes the most facilities), but does not contain data for all inventory years (1990 through 2010). The EIA data can be used to supplement years not available in the GHGRP dataset and corroborate MSW mass flow tonnage obtained for years in which GHGRP data are available. These MSW mass flow tonnages currently influence calculations for CO_2 and non-CO_2 emissions.

Additional improvements will focus on investigating new methods and sources for CO_2 emission estimates. As part of the Public Review process of this year's Inventory cycle, EPA proposed a new method for calculating emissions associated with waste incineration. The proposed method relied on MSW tonnage estimates back calculated from GHGRP reporting data and MSW assumed carbon content factors based on the EPA's Facts and Figures Reports. Based on review and discussions with industry representatives it was felt that the proposed approach could lead to an overestimate of fossil carbon content of waste combusted. Therefore, the approach used here reverts to the existing methodology used in past calculations.

Future, proposed improvements to the current CO_2 emissions estimation methodology build off the work done for the proposed approach and include the calculation of an overall carbon content for MSW incinerated. GHGRP and EIA both provide emissions information for CO_2, which will allow EPA to calculate an overall carbon content of MSW incinerated and apply this to MSW mass flows. Further research is required to compare the carbon contents of MSW incinerated from GHGRP and EIA.

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 CH_4 to the atmosphere: underground mining, surface mining, and post-mining (i.e., coal-handling) activities. While surface mines account for the majority of U.S. coal production, underground coal mines contribute the largest share of CH_4 emissions (see Table 3-30 and Table 3-31) due to the higher CH_4 content of coal in the deeper underground coal seams. In 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

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

Surface coal mines liberate CH_4 as the overburden is removed and the coal is exposed to the atmosphere. Methane emissions are normally a function of coal rank (a classification related to the percentage of carbon in the coal) and depth. Surface coal mines typically produce lower-rank coals and remove less than 250 feet of overburden, so their level of emissions is much lower than from underground mines.

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

Total CH_4 emissions in 2019 were estimated to be 1,895 kt (47.4 MMT CO_2 Eq.), a decline of approximately 51 percent since 1990 (see Table 3-30 and Table 3-31). In 2019, underground mines accounted for approximately 73 percent of total emissions, surface mines accounted for 13 percent, and post-mining activities accounted for 14 percent. In 2019, total CH_4 emissions from coal mining decreased by approximately 10 percent relative to the previous year. This decrease was due to a decrease in annual coal production and a decrease in reported annual ventilation emissions.[67] The amount of CH_4 recovered and used in 2019 decreased by approximately 17 percent compared to 2018 levels. In 2019, all but two mines reported lower levels of CH_4 recovered and used compared to 2018 levels.

Table 3-30: CH_4 Emissions from Coal Mining (MMT CO_2 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**		**11.9**		**8.7**	**6.8**	**7.2**	**7.0**	**6.4**
Post-Mining (UG)	**9.2**		**7.6**		**5.8**	**4.8**	**5.3**	**5.3**	**5.2**
Post-Mining (Surface)	**2.3**		**2.6**		**1.9**	**1.5**	**1.6**	**1.5**	**1.4**
Total	**96.5**		**64.1**		**61.2**	**53.8**	**54.8**	**52.7**	**47.4**

Table 3-31: CH_4 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**		**475**		**347**	**273**	**290**	**280**	**255**
Post-Mining (UG)	**368**		**306**		**231**	**193**	**213**	**212**	**206**
Post-Mining (Surface)	**93**		**103**		**75**	**59**	**63**	**61**	**55**
Total	**3,860**		**2,565**		**2,449**	**2,154**	**2,191**	**2,109**	**1,895**

Methodology

EPA uses an IPCC Tier 3 method for estimating CH_4 emissions from underground coal mining and an IPCC Tier 2 method for estimating CH_4 emissions from surface mining and post-mining activities (for both coal production from underground mines and surface mines). The methodology for estimating CH_4 emissions from coal mining consists of two steps:

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

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

surface mines and post-mining activities consists of multiplying basin-specific coal production by basin-specific gas content and an emission factor.

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

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

Step 1.1: Estimate CH_4 Liberated from Ventilation Systems

To estimate CH_4 liberated from ventilation systems, EPA uses data collected through its Greenhouse Gas Reporting Program (GHGRP)[68] (Subpart FF, "Underground Coal Mines"), data provided by the U.S. Mine Safety and Health Administration (MSHA) (MSHA 2020), and occasionally data collected from other sources on a site-specific level (e.g., state gas production databases). Since 2011, the nation's "gassiest" underground coal mines—those that liberate more than 36,500,000 actual cubic feet of CH_4 per year (about 17,525 MT CO_2 Eq.)—have been required to report to EPA's GHGRP (EPA 2020).[69] Mines that report to EPA's GHGRP must report quarterly measurements of CH_4 emissions from ventilation systems; they have the option of recording and reporting their own measurements, or using the measurements taken by MSHA as part of that agency's quarterly safety inspections of all mines in the United States with detectable CH_4 concentrations.[70]

Since 2013, ventilation CH_4 emission estimates have been calculated based on both quarterly GHGRP data submitted by underground mines and on quarterly measurement data obtained directly from MSHA. Because not all mines report under EPA's GHGRP, the emissions of the mines that do not report must be calculated using MSHA data. The MSHA data also serves as a quality assurance tool for validating GHGRP data. For GHGRP data, reported quarterly ventilation methane emissions (metric tons) are summed for each mine to develop mine-specific annual ventilation emissions. For MSHA data, the average daily CH_4 emission rate for each mine is determined using the CH_4 total for all data measurement events conducted during the calendar year and total duration of all data measurement events (in days). The calculated average daily CH_4 emission rate is then multiplied by 365 days to estimate annual ventilation CH_4 emissions for the MSHA dataset.

Step 1.2: Estimate CH_4 Liberated from Degasification Systems

Particularly gassy underground mines also use degasification systems (e.g., wells or boreholes) to remove CH_4 before, during, or after mining. This CH_4 can then be collected for use or vented to the atmosphere. Nineteen mines used degasification systems in 2019 and 17 of these mines reported the CH_4 removed through these systems to EPA's GHGRP under Subpart FF (EPA 2020). Based on the weekly measurements reported to EPA's GHGRP, degasification data summaries for each mine are added to estimate the CH_4 liberated from degasification systems. Thirteen of the 19 mines with degasification systems had operational CH_4 recovery and use projects (see step 1.3 below).[71]

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[68] 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).

[69] 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.

[70] MSHA records coal mine CH_4 readings with concentrations of greater than 50 ppm (parts per million) CH_4. Readings below this threshold are considered non-detectable.

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

Degasification data reported to EPA's GHGRP by underground coal mines is the primary source of data used to develop estimates of CH_4 liberated from degasification systems. Data reported to EPA's GHGRP were used exclusively to estimate CH_4 liberated from degasification systems at 14 of the 19 mines that used degasification systems in 2019. Data from state gas well production databases were used exclusively for two mines and state gas well production data were used to supplement GHGRP degasification data for the remaining three mines (DMME 2020, GSA 2020, and WVGES 2020).

For pre-mining wells, cumulative degasification volumes that occur prior to the well being mined through are attributed to the mine in the inventory year in which the well is mined through.[72] EPA's GHGRP does not require gas production from virgin coal seams (coalbed methane) to be reported by coal mines under Subpart FF.[73] Most pre-mining wells drilled from the surface are considered coalbed methane wells prior to mine-through and associated CH_4 emissions are reported under another subpart of the GHGRP (Subpart W, "Petroleum and Natural Gas Systems"). As a result, GHGRP data must be supplemented to estimate cumulative degasification volumes that occurred prior to well mine-through. There were five mines with degasification systems that include pre-mining wells that were mined through in 2019. For three of these mines, GHGRP data were supplemented with historical data from state gas well production databases (GSA 2020 and WVGES 2020), as well as with mine-specific information regarding the locations and dates on which the pre-mining wells were mined through (JWR 2010; El Paso 2009; ERG 2020). State gas well production data were exclusively used for the remaining two mines (DMME 2020 and GSA 2020).

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

Thirteen mines had CH_4 recovery and use projects in place in 2019, including one mine that had two recovery and use projects. Thirteen of these projects involved degasification systems and one involved a ventilation air methane abatement project (VAM). Eleven of these mines sold the recovered CH_4 to a pipeline, including one that also used CH_4 to fuel a thermal coal dryer. One mine used recovered CH_4 to heat mine ventilation air (data were unavailable for estimating CH_4 recovery at this mine). One mine destroyed the recovered CH_4 (VAM) using Regenerative Thermal Oxidation (RTO) without energy recovery.

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

- EPA's GHGRP data was exclusively used to estimate the CH_4 recovered and used from seven of the 12 mines that deployed degasification systems in 2019. Based on weekly measurements, the GHGRP degasification destruction data summaries for each mine are added together to estimate the CH_4 recovered and used from degasification systems.
- State sales data were used to estimate CH_4 recovered and used from the remaining five mines that deployed degasification systems in 2019 (DMME 2020, GSA 2020). These five mines intersected pre-mining wells in 2019. Supplemental information is used for these mines because estimating CH_4 recovery and use from pre-mining wells requires additional data not reported under Subpart FF of EPA's GHGRP (see discussion in step 1.2 above) to account for the emissions avoided prior to the well being mined through. The supplemental data is obtained from state gas production databases as well as mine-specific information on the timing of mined-through pre-mining wells.
- For the single mine that employed VAM for CH_4 recovery and use, the estimates of CH_4 recovered and used were obtained from the mine's offset verification statement (OVS) submitted to the California Air Resources Board (CARB) (McElroy OVS 2020).

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

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

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

Mine-specific data are not available for estimating CH_4 emissions from surface coal mines or for post-mining activities. For surface mines, basin-specific coal production obtained from the Energy Information Administration's *Annual Coal Report* (EIA 2020) is multiplied by basin-specific CH_4 contents (EPA 1996, 2005) and a 150 percent emission factor (to account for CH_4 from over- and under-burden) to estimate CH_4 emissions (King 1994, Saghafi 2013). For post-mining activities, basin-specific coal production is multiplied by basin-specific CH_4 contents and a mid-range 32.5 percent emission factor for CH_4 desorption during coal transportation and storage (Creedy 1993). Basin-specific in situ gas content data were compiled from AAPG (1984) and USBM (1986).

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis was conducted for the coal mining source category using the IPCC-recommended Approach 2 uncertainty estimation methodology. Because emission estimates from underground ventilation systems were based on actual measurement data from EPA's GHGRP or from MSHA, uncertainty is relatively low. A degree of imprecision was introduced because the ventilation air measurements used were not continuous but rather quarterly instantaneous readings that were used to determine the average annual emission rates. Additionally, the measurement equipment used can be expected to have resulted in an average of 10 percent overestimation of annual CH_4 emissions (Mutmansky & Wang 2000). Equipment measurement uncertainty is applied to GHGRP data.

Estimates of CH_4 liberated and recovered by degasification systems are relatively certain for utilized CH_4 because of the availability of EPA's GHGRP data and gas sales information. Many of the liberation and recovery estimates use data on wells within 100 feet of a mined area. However, uncertainty exists concerning the radius of influence of each well. The number of wells counted, and thus the liberated CH_4 and avoided emissions, may vary if the drainage area is found to be larger or smaller than estimated.

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

Surface mining and post-mining emissions are associated with considerably more uncertainty than underground mines, because of the difficulty in developing accurate emission factors from field measurements. However, since underground emissions constitute the majority of total coal mining emissions, the uncertainty associated with underground emissions is the primary factor that determines overall uncertainty.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-32. Coal mining CH_4 emissions in 2019 were estimated to be between 43.2 and 57.0 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 8.8 percent below to 20.3 percent above the 2019 emission estimate of 47.4 MMT CO_2 Eq.

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

Source	Gas	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 Mining	CH_4	47.4	43.2	57.0	-8.8%	+20.3%

[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 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 degasification CH_4 emissions and CH_4 emissions avoided from underground mining. The change in both the degasification 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 coal production numbers were revised by EIA, 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 an increase of 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 include estimating fugitive CO_2 emissions from underground and surface mining, based on methods included in the *2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories*.

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

Underground coal mines contribute the largest share of coal mine methane (CMM) emissions, with active underground mines the leading source of underground emissions. However, mines also continue to release CH_4 after closure. As mines mature and coal seams are mined through, mines are closed and abandoned. Many are sealed and some flood through intrusion of groundwater or surface water into the void. Shafts or portals are generally filled with gravel and capped with a concrete seal, while vent pipes and boreholes are plugged in a manner similar to oil and gas wells. Some abandoned mines are vented to the atmosphere to prevent the buildup of CH_4 that may find its way to surface structures through overburden fractures. As work stops within the mines, CH_4 liberation decreases but it does not stop completely. Following an initial decline, abandoned mines can liberate CH_4 at a near-steady rate over an extended period of time, or, if flooded, produce gas for only a few years. The gas can migrate to the surface through the conduits described above, particularly if they have not been sealed adequately. In addition, diffuse emissions can occur when CH_4 migrates to the surface through cracks and fissures in the strata overlying the coal mine. The following factors influence abandoned mine emissions:

- Time since abandonment;
- Gas content and adsorption characteristics of coal;
- CH_4 flow capacity of the mine;
- Mine flooding;
- Presence of vent holes; and
- Mine seals.

Annual gross abandoned mine CH_4 emissions ranged from 7.2 to 10.8 MMT CO_2 Eq. from 1990 to 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 CO_2 Eq.) due to the large number of gassy mine[74] 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 CO_2 Eq. (355 kt CH_4) in 2018 to 8.5 (341 kt CH_4) MMT CO_2 Eq. in 2019 (see Table 3-33 and Table 3-34). Gross emissions are reduced by CH_4 recovered and used at 45 mines, resulting in net emissions in 2019 of 5.9 MMT CO_2 Eq.

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

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

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

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

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

+ Does not exceed 0.5 kt.

Methodology

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

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

for abandoned coal mines. Existing data on abandoned mine emissions through time, although sparse, appear to fit the hyperbolic type of decline curve used in forecasting production from natural gas wells.

In order to estimate CH_4 emissions over time for a given abandoned mine, it is necessary to apply a decline function, initiated upon abandonment, to that mine. In the analysis, mines were grouped by coal basin with the assumption that they will generally have the same initial pressures, permeability and isotherm. As CH_4 leaves the system, the reservoir pressure (Pr) declines as described by the isotherm's characteristics. The emission rate declines because the mine pressure (Pw) is essentially constant at atmospheric pressure for a vented mine, and the productivity index (PI), which is expressed as the flow rate per unit of pressure change, is essentially constant at the pressures of interest (atmospheric to 30 psia). The CH_4 flow rate is determined by the laws of gas flow through porous media, such as Darcy's Law. A rate-time equation can be generated that can be used to predict future emissions. This decline through time is hyperbolic in nature and can be empirically expressed as:

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

where,

q	=	Gas flow rate at time t in million cubic feet per day (mmcfd)
q_i	=	Initial gas flow rate at time zero (t_o), mmcfd
b	=	The hyperbolic exponent, dimensionless
D_i	=	Initial decline rate, 1/year
t	=	Elapsed time from t_o (years)

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

The decline curves created to model the gas emission rate of coal mines must account for factors that decrease the rate of emissions after mining activities cease, such as sealing and flooding. Based on field measurement data, it was assumed that most U.S. mines prone to flooding will become completely flooded within eight years and therefore will no longer have any measurable CH_4 emissions. Based on this assumption, an average decline rate for flooded mines was established by fitting a decline curve to emissions from field measurements. An exponential equation was developed from emissions data measured at eight abandoned mines known to be filling with water located in two of the five basins. Using a least squares, curve-fitting algorithm, emissions data were matched to the exponential equation shown below. For this analysis of flooded abandoned mines, there was not enough data to establish basin-specific equations, as was done with the vented, non-flooding mines (EPA 2004). This decline through time can be empirically expressed as:

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

where,

q	=	Gas flow rate at time t in mmcfd
q_i	=	Initial gas flow rate at time zero (t_o), mmcfd
D	=	Decline rate, 1/year
t	=	Elapsed time from t_o (years)

Seals have an inhibiting effect on the rate of flow of CH_4 into the atmosphere compared to the flow rate that would exist if the mine had an open vent. The total volume emitted will be the same, but emissions will occur over a longer period of time. The methodology, therefore, treats the emissions prediction from a sealed mine similarly to the emissions prediction from a vented mine, but uses a lower initial rate depending on the degree of sealing. A computational fluid dynamics simulator was used with the conceptual abandoned mine model to predict the decline curve for inhibited flow. The percent sealed is defined as 100 × (1 – [initial emissions from sealed mine / emission rate at abandonment prior to sealing]). Significant differences are seen between 50 percent, 80 percent and 95 percent closure. These decline curves were therefore used as the high, middle, and low values for emissions from sealed mines (EPA 2004).

For active coal mines, those mines producing over 100 thousand cubic feet per day (mcfd) of CH_4 account for about 98 percent of all CH_4 emissions. This same relationship is assumed for abandoned mines. It was determined that the 527 abandoned mines closed after 1972 produced CH_4 emissions greater than 100 mcfd when active. Further, the status of 304 of the 527 mines (or 58 percent) is known to be either: 1) vented to the atmosphere; 2) sealed to some degree (either earthen or concrete seals); or 3) flooded (enough to inhibit CH_4 flow to the atmosphere). The remaining 42 percent of the mines whose status is unknown were placed in one of these three categories by applying a probability distribution analysis based on the known status of other mines located in the same coal basin (EPA 2004). Table 3-35 presents the count of mines by post-abandonment state, based on EPA's probability distribution analysis.

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

Basin	Sealed	Vented	Flooded	Total Known	Unknown	Total Mines
Central Appl.	42	26	52	120	146	266
Illinois	34	3	14	51	31	82
Northern Appl.	47	22	16	85	39	124
Warrior Basin	0	0	16	16	0	16
Western Basins	28	4	2	34	10	44
Total	**151**	**55**	**100**	**306**	**226**	**532**

Inputs to the decline equation require the average CH_4 emission rate prior to abandonment and the date of abandonment. Generally, these data are available for mines abandoned after 1971; however, such data are largely unknown for mines closed before 1972. Information that is readily available, such as coal production by state and county, is helpful but does not provide enough data to directly employ the methodology used to calculate emissions from mines abandoned before 1972. It is assumed that pre-1972 mines are governed by the same physical, geologic, and hydrologic constraints that apply to post-1971 mines; thus, their emissions may be characterized by the same decline curves.

During the 1970s, 78 percent of CH_4 emissions from coal mining came from seventeen counties in seven states. Mine closure dates were obtained for two states, Colorado and Illinois, for the hundred-year period extending from 1900 through 1999. The data were used to establish a frequency of mine closure histogram (by decade) and applied to the other five states with gassy mine closures. As a result, basin-specific decline curve equations were applied to the 145 gassy coal mines estimated to have closed between 1920 and 1971 in the U.S., representing 78 percent of the emissions. State-specific, initial emission rates were used based on average coal mine CH_4 emissions rates during the 1970s (EPA 2004).

Abandoned mine emission estimates are based on all closed mines known to have active mine CH_4 ventilation emission rates greater than 100 mcfd at the time of abandonment. For example, for 1990 the analysis included 145 mines closed before 1972 and 258 mines closed between 1972 and 1990. Initial emission rates based on MSHA reports, time of abandonment, and basin-specific decline curves influenced by a number of factors were used to calculate annual emissions for each mine in the database (MSHA 2020). Coal mine degasification data are not available for years prior to 1990, thus the initial emission rates used reflect only ventilation emissions for pre-1990 closures. CH_4 degasification amounts were added to the quantity of CH_4 vented to determine the total CH_4 liberation rate for all mines that closed between 1992 and 2019. Since the sample of gassy mines described above is assumed to account for 78 percent of the pre-1972 and 98 percent of the post-1971 abandoned mine emissions, the modeled results were multiplied by 1.22 and 1.02 to account for all U.S. abandoned mine emissions.

From 1993 through 2019, emission totals were downwardly adjusted to reflect CH_4 emissions avoided from those abandoned mines with CH_4 recovery and use or destruction systems. The Inventory totals were not adjusted for abandoned mine CH_4 emissions avoided from 1990 through 1992, because no data was reported for abandoned coal mine CH_4 recovery and use or destruction projects during that time.

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis was conducted to estimate the uncertainty surrounding the estimates of CH_4 emissions from abandoned underground coal mines. The uncertainty analysis provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the Inventory estimate. The results provide the range within which, with 95 percent certainty, emissions from this source category are likely to fall.

As discussed above, the parameters for which values must be estimated for each mine in order to predict its decline curve are: 1) the coal's adsorption isotherm; 2) CH_4 flow capacity as expressed by permeability; and 3) pressure at abandonment. Because these parameters are not available for each mine, a methodological approach to estimating emissions was used that generates a probability distribution of potential outcomes based on the most likely value and the probable range of values for each parameter. The range of values is not meant to capture the extreme values, but rather values that represent the highest and lowest quartile of the cumulative probability density function of each parameter. Once the low, mid, and high values are selected, they are applied to a probability density function.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-36. Annual abandoned coal mine CH_4 emissions in 2019 were estimated to be between 4.6 and 7.1 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 22 percent below to 19 percent above the 2019 emission estimate of 5.9 MMT CO_2 Eq. One of the reasons for the relatively narrow range is that mine-specific data is available for use in the methodology for mines closed in 1972 and later years. Emissions from mines closed prior to 1972 have the largest degree of uncertainty because no mine-specific CH_4 liberation rates exist.

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

Source	Gas	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
Abandoned Underground Coal Mines	CH_4	5.9	4.6	7.1	-22.4%	+19.2%

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

QA/QC and Verification

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

3.6 Petroleum Systems (CRF Source Category 1B2a)

This IPCC category (1B2a) is for fugitive emissions, which per IPCC include emissions from leaks, venting, and flaring. Methane emissions from petroleum systems are primarily associated with onshore and offshore crude oil production, transportation, and refining operations. During these activities, CH_4 is released to the atmosphere as emissions from leaks, venting (including emissions from operational upsets), and flaring. Carbon dioxide emissions from petroleum systems are primarily associated with onshore and offshore crude oil production and refining operations. Note, CO_2 emissions in Petroleum Systems exclude all combustion emissions (e.g., engine combustion) except for flaring CO_2 emissions. All combustion CO_2 emissions (except for flaring) are accounted for in the fossil fuel combustion chapter (see Section 3). Emissions of N_2O from petroleum systems are primarily associated with flaring. Total greenhouse gas emissions (CH_4, CO_2, and N_2O) from petroleum systems in 2019 were 86.4 MMT CO_2 Eq., an increase of 47 percent from 1990, primarily due to increases in CO_2 emissions. Since 2009, total emissions increased by 64 percent and since 2018, total emissions increased by 16 percent. Total CO_2 emissions from petroleum systems in 2019 were 47.3 MMT CO_2 (47,269 kt CO_2), 3.9 times higher than in 1990. Total CO_2 emissions in 2019 were 2.5 times higher than in 2009 and 27 percent higher than in 2018. Total CH_4 emissions from petroleum systems in 2019 were 39.1 MMT CO_2 Eq. (1,563 kt CH_4), a decrease of 20 percent from 1990. Since 2009, total CH_4 emissions increased by less than 0.5 percent; and since 2018, CH_4 emissions increased by 5 percent. Total N_2O emissions from petroleum systems in 2019 were 0.05 MMT CO_2 Eq. (0.16 kt N_2O), 1.8 times higher than in 1990, 1.5 times higher than in 2009, and 13 percent higher than in 2018. Since 1990, U.S. oil production has increased by 67 percent. In 2019, production was 129 percent higher than in 2009 and 12 percent higher than in 2018.

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 petroleum systems in this year's Inventory include:

- Incorporation of an estimate for produced water
- Updates to well counts using the most recent data from Enverus
- Recalculations due to GHGRP submission revisions

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

Exploration. Exploration includes well drilling, testing, and completions. Exploration accounted for approximately 1 percent of total CH_4 emissions (including leaks, vents, and flaring) from petroleum systems in 2019. The predominant sources of CH_4 emissions from exploration are hydraulically fractured oil well completions. Other sources include well testing, well drilling, and well completions without hydraulic fracturing. Since 1990, exploration CH_4 emissions have decreased 91 percent, and while the number of hydraulically fractured wells completed increased by a factor of 2.9, there were decreases in the fraction of such completions without reduced emissions completions (RECs) or flaring (from 90 percent in 1990 to less than 1 percent in 2019). Emissions of CH_4 from exploration were highest in 2012, nearly 30 times higher than in 2019; and lowest in 2019. Emissions of CH_4 from exploration decreased 30 percent from 2018 to 2019, due to a decrease in hydraulically fractured oil well completions with flaring. Exploration accounts for 4 percent of total emissions (including leaks, vents, and flaring) from petroleum systems in 2019. Emissions of CO_2 from exploration in 2019 were 7 times higher than in 1990, and decreased by 28 percent from 2018, due to a decrease in hydraulically fractured oil well completions with flaring. Emissions of CO_2 from exploration were highest in 2014, around 33 percent higher than in 2019. Exploration accounts for nearly 2 percent of total N_2O emissions from petroleum systems in 2019. Emissions of N_2O from exploration in 2019 are 4.3 times higher than in 1990, and 37 percent lower than in 2018, due to the abovementioned changes in hydraulically fractured oil well completions with flaring.

Production. Production accounted for 96 percent of total CH_4 emissions (including leaks, vents, and flaring) from petroleum systems in 2019. The predominant sources of emissions from production field operations are pneumatic controllers, offshore oil platforms, gas engines, equipment leaks, produced water, and associated gas flaring. These six sources together accounted for 82 percent of the CH_4 emissions from production. Since 1990, CH_4 emissions from production have decreased by 16 percent due to decreases in emissions from offshore platforms, tanks, and pneumatic controllers. Overall, production segment CH_4 emissions increased by 5 percent from 2018 levels due primarily to increased associated gas venting and flaring emissions in the Gulf Coast and Williston basins. Production emissions account for 85 percent of the total CO_2 emissions (including leaks, vents, and flaring) from petroleum systems in 2019. The principal sources of CO_2 emissions are associated gas flaring, miscellaneous production flaring, and oil tanks with flares. These three sources together account for 98 percent of the CO_2

emissions from production. In 2019, CO_2 emissions from production were 3.9 times higher than in 1990, due to increases in flaring emissions from associated gas flaring, miscellaneous production flaring, and tanks. Overall, production segment CO_2 emissions increased by 32 percent from 2018 levels primarily due to an increase in associated gas flaring in the Williston Basin. Production emissions accounted for 67 percent of the total N_2O emissions from petroleum systems in 2019. The principal sources of N_2O emissions are associated gas flaring, oil tanks with flares, and miscellaneous production flaring. In 2019, N_2O emissions from production were 3.2 times higher than in 1990 and 2.5 times higher than in 2009, due primarily to increases in N_2O from associated gas flaring. In 2019, N_2O emissions from production increased by 6 percent from 2018 levels.

Crude Oil Transportation. Emissions from crude oil transportation account for a very small percentage of the total emissions (including leaks, vents, and flaring) from petroleum systems and have little impact on the overall emissions. Crude oil transportation activities account for less than 1 percent of total CH_4 emissions from petroleum systems. Emissions from tanks, marine loading, and truck loading operations account for 76 percent of CH_4 emissions from crude oil transportation. Since 1990, CH_4 emissions from transportation have increased by 40 percent. In 2019, CH_4 emissions from transportation increased by 8 percent from 2018 levels. Crude oil transportation activities account for less than 0.01 percent of total CO_2 emissions from petroleum systems. Emissions from tanks, marine loading, and truck loading operations account for 76 percent of CO_2 emissions from crude oil transportation.

Crude Oil Refining. Crude oil refining processes and systems account for 2 percent of total fugitive (including leaks, vents, and flaring) CH_4 emissions from petroleum systems. This low share is because most of the CH_4 in crude oil is removed or escapes before the crude oil is delivered to the refineries. There is an insignificant amount of CH_4 in all refined products. Within refineries, flaring accounts for 47 percent of the CH_4 emissions, while uncontrolled blowdowns, delayed cokers, and process vents account for 15, 12, and 10 percent, respectively. Fugitive CH_4 emissions from refining of crude oil have increased by 32 percent since 1990, and increased 16 percent from 2018; however, like the transportation subcategory, this increase has had little effect on the overall emissions of CH_4 from petroleum systems. Crude oil refining processes and systems account for 11 percent of total fugitive (including leaks, vents, and flaring) CO_2 emissions from petroleum systems. Of the total fugitive CO_2 emissions from refining, almost all (about 99 percent) of it comes from flaring.[75] Since 1990, refinery fugitive CO_2 emissions increased by 53 percent and have increased by 34 percent from the 2018 levels, due to an increase in flaring. Flaring occurring at crude oil refining processes and systems accounts for 31 percent of total fugitive N_2O emissions from petroleum systems. Refinery fugitive N_2O emissions increased by 61 percent from 1990 to 2019 and increased by 40 percent from 2018 levels.

Table 3-37: Total Greenhouse Gas Emissions (CO_2, CH_4, and N_2O) from Petroleum Systems (MMT CO_2 Eq.)

Activity	1990	2005	2015	2016	2017	2018	2019
Exploration	3.3	4.9	4.2	1.7	2.1	3.3	2.4
Production	51.2	42.0	64.6	54.4	57.5	66.4	77.9
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	**58.6**	**51.5**	**73.9**	**61.1**	**64.4**	**74.5**	**86.4**

Note: Totals may not sum due to independent rounding.

Table 3-38: CH_4 Emissions from Petroleum Systems (MMT CO_2 Eq.)

Activity	1990	2005	2015	2016	2017	2018	2019
Exploration	**3.0**	**4.5**	**2.1**	**0.5**	**0.4**	**0.4**	**0.3**

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

Production	**45.1**	**34.0**	**38.4**	**37.7**	**38.0**	**35.9**	**37.7**
Pneumatic Controllers	19.8	16.8	18.8	19.6	20.0	17.3	17.5
Offshore Production	9.3	6.5	5.5	5.1	5.1	5.0	5.0
Gas Engines	2.2	1.8	2.5	2.4	2.4	2.4	2.4
Equipment Leaks	2.0	2.0	2.5	2.4	2.4	2.4	2.3
Produced Water	2.3	1.6	2.1	1.9	2.0	2.1	2.1
Assoc Gas Flaring	0.5	0.4	1.2	0.7	1.0	1.7	2.0
Other Sources	8.9	4.9	5.8	5.5	5.2	5.1	6.2
Crude Oil Transportation	**0.2**	**0.1**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**
Refining	**0.7**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.9**
Total	**48.9**	**39.5**	**41.5**	**39.2**	**39.3**	**37.3**	**39.1**

Note: Totals may not sum due to independent rounding.

Table 3-39: CH_4 Emissions from Petroleum Systems (kt CH_4)

Activity	1990	2005	2015	2016	2017	2018	2019
Exploration	**119**	**182**	**83**	**19**	**14**	**15**	**11**
Production	**1,802**	**1,361**	**1,535**	**1,508**	**1,519**	**1,438**	**1,507**
Pneumatic Controllers	792	673	750	785	799	694	699
Offshore Production	374	261	221	206	205	199	201
Gas Engines	88	74	99	95	94	96	98
Equipment Leaks	82	81	101	97	96	95	94
Produced Water	91	62	82	77	79	83	85
Assoc Gas Flaring	20	15	49	29	38	68	82
Other Sources	355	196	233	219	207	203	249
Crude Oil Transportation	**7**	**5**	**8**	**8**	**8**	**8**	**9**
Refining	**27**	**31**	**33**	**33**	**33**	**31**	**36**
Total	**1,955**	**1,579**	**1,659**	**1,568**	**1,574**	**1,492**	**1,563**

Note: Totals may not sum due to independent rounding.

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

Activity	1990	2005	2015	2016	2017	2018	2019
Exploration	0.3	0.3	2.2	1.2	1.7	2.9	2.1
Production	6.1	8.0	26.2	16.6	19.6	30.5	40.2
Transportation	+	+	+	+	+	+	+
Crude Refining	3.3	3.7	4.1	4.0	3.7	3.7	5.0
Total	**9.7**	**12.1**	**32.4**	**21.8**	**25.0**	**37.1**	**47.3**

Note: Totals may not sum due to independent rounding.

Table 3-41: CO_2 Emissions from Petroleum Systems (kt CO_2)

Activity	1990	2005	2015	2016	2017	2018	2019
Exploration	313	340	2,182	1,212	1,700	2,906	2,081
Production	6,111	7,991	26,163	16,643	19,564	30,473	40,168
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	**9,709**	**12,059**	**32,412**	**21,847**	**24,979**	**37,115**	**47,269**

Note: Totals may not sum due to independent rounding.

Table 3-42: N_2O Emissions from Petroleum Systems (Metric Tons CO_2 Eq.)

Activity	1990	2005	2015	2016	2017	2018	2019
Exploration	162	173	1,118	617	744	1,370	860
Production	7,502	8,050	20,300	15,087	15,812	29,636	31,269
Transportation	NE	NE	NE	NE	NE	NE	NE
Crude Refining	9,138	10,372	11,656	11,575	10,796	10,557	14,749
Total	**16,802**	**18,596**	**33,074**	**27,279**	**27,352**	**41,562**	**46,878**

Note: Totals may not sum due to independent rounding.

NE (Not Estimated)

Table 3-43: N_2O Emissions from Petroleum Systems (Metric Tons N_2O)

Activity	1990	2005	2015	2016	2017	2018	2019
Exploration	0.5	0.6	3.8	2.1	2.5	4.6	2.9
Production	25.2	27.0	68.1	50.6	53.1	99.4	104.9
Transportation	NE	NE	NE	NE	NE	NE	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**	**91.8**	**139.5**	**157.3**

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. Key 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, *Nonpoint Oil and Gas Emission Estimation Tool* (EPA 2017), 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.[76] 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 2019, and trends in emissions reflect changes in activity levels. Emission factors from EPA 1999 are used for all other production and transportation activities.

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

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

For the exploration and production segments, N_2O emissions were estimated for flaring sources using GHGRP or BOEM OGOR-B data and the same method used for CO_2. Sources with N_2O emissions in the exploration segment include well testing and HF completions with flaring. Sources with N_2O emissions in the production segment include associated gas flaring, tank flaring, miscellaneous production flaring, HF workovers with flaring, and flaring from offshore production sources.

For crude oil transportation, emission factors for CH_4 were largely developed using data from EPA (1997), API (1992), and EPA (1999). Emission factors for CO_2 were estimated by multiplying the CH_4 emission factors by a conversion factor, which is the ratio of CO_2 content and CH_4 content in whole crude post-separator.

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

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

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

Activity Data. References for activity data include Enverus data (Enverus 2021), Energy Information Administration (EIA) reports, *Methane Emissions from the Natural Gas Industry by the Gas Research Institute and EPA* (EPA/GRI 1996), *Estimates of Methane Emissions from the U.S. Oil Industry* (EPA 1999), consensus of industry peer review panels, BOEM reports, the Oil & Gas Journal, the Interstate Oil and Gas Compact Commission, the United States Army Corps of Engineers, and analysis of GHGRP data (EPA 2020).

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

A complete list of references for emission factors and activity data by emission source is provided in Annex 3.5. The U.S. reports data to the UNFCCC using this Inventory report along with Common Reporting Format (CRF) tables. This note is provided for those reviewing the CRF tables: The notation key "IE" is used for CO_2 and CH_4 emissions from venting and flaring in CRF table 1.B.2. Disaggregating flaring and venting estimates across the Inventory would involve the application of assumptions and could result in inconsistent reporting and, potentially, decreased transparency. Data availability varies across segments within oil and gas activities systems, and emission factor data available for activities that include flaring can include emissions from multiple sources (flaring, venting and leaks).

Uncertainty and Time-Series Consistency

EPA conducted a quantitative uncertainty analysis using the IPCC Approach 2 methodology (Monte Carlo Simulation technique) to characterize uncertainty for petroleum systems. For more information on the approach, please see the memorandum Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2016: Natural Gas and Petroleum Systems Uncertainty Estimates (2018 Uncertainty Memo).[77]

EPA used Microsoft Excel's @RISK add-in tool to estimate the 95 percent confidence bound around CH_4 and CO_2 emissions from petroleum systems for the current Inventory. Uncertainty estimates for N_2O were not developed given the minor contribution of N_2O to emission totals. For the CH_4 uncertainty analysis, EPA focused on the eight highest methane-emitting sources for the year 2019, which together emitted 76 percent of methane from petroleum systems in 2019, and extrapolated the estimated uncertainty for the remaining sources. Uncertainty was not previously estimated specifically for CO_2 emissions, instead the uncertainty bounds calculated for CH_4 were applied to CO_2 emissions estimates. As part of the stakeholder process for the current Inventory, EPA developed an update to the uncertainty analysis for CO_2. The update is documented in the memorandum, *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2019: Update for Natural Gas and Petroleum Systems CO_2 Uncertainty Estimates.*[78] EPA ultimately applied the same approach as was developed for CH_4. For the CO_2 uncertainty analysis, EPA focused on the 3 highest-emitting sources for the year 2018 (from the previous 1990-2018 Inventory), which together emitted 80 percent of CO_2 from petroleum systems in 2018, and extrapolated the estimated uncertainty for the remaining sources. The CO_2 uncertainty calculations were developed as part of the stakeholder process and were based on the previous 1990-2018 Inventory; as a result, the uncertainty results from last year's Inventory for year 2018 are applied for this year's uncertainty analysis. In future years, the CO_2 uncertainty bounds will be calculated using the most recent Inventory data. The @RISK add-in provides for the specification of probability density functions (PDFs) for key variables within a computational structure that mirrors the calculation of the inventory estimate. The IPCC guidance notes that in using this method, "some uncertainties

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

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

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

The results presented below provide the 95 percent confidence bound within which actual emissions from this source category are likely to fall for the year 2019, using the recommended IPCC methodology. The results of the Approach 2 uncertainty analysis are summarized in Table 3-44. Petroleum systems CH_4 emissions in 2019 were estimated to be between 29.7 and 50.3 MMT CO_2 Eq., while CO_2 emissions were estimated to be between 34.5 and 66.7 MMT CO_2 Eq. at a 95 percent confidence level. Uncertainty bounds for other years of the time series have not been calculated, but uncertainty is expected to vary over the time series. For example, years where many emission sources are calculated with interpolated data would likely have higher uncertainty than years with predominantly year-specific data. In addition, the emission sources that contribute the most to CH_4 and CO_2 emissions are different over the time series, particularly when comparing recent years to early years in the time series. For example, associated gas venting emissions were higher and flaring emissions were lower in early years of the time series, compared to recent years. Technologies also changed over the time series (e.g., reduced emissions completions were not used early in the time series).

Table 3-44: Approach 2 Quantitative Uncertainty Estimates for CH_4 and CO_2 Emissions from Petroleum Systems (MMT CO_2 Eq. and Percent)

Source	Gas	2019 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	39.1	29.7	50.3	-24%	+29%
Petroleum Systems	CO_2	47.3	34.5	66.7	-27%	+41%

[a] Range of emission estimates estimated by applying the 95 percent confidence intervals obtained from the Monte Carlo Simulation analysis conducted for the year 2019 CH_4 and year 2018 CO_2 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.

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

QA/QC and Verification Discussion

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

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

In recent years, several studies have measured emissions at the source level and at the national or regional level and calculated emission estimates that may differ from the Inventory. There are a variety of potential uses of data from new studies, including replacing a previous estimate or factor, verifying or QA of an existing estimate or factor, and identifying areas for updates. In general, there are two major types of studies related to oil and gas greenhouse gas data: studies that focus on measurement or quantification of emissions from specific activities, processes, and equipment, and studies that use tools such as inverse modeling to estimate the level of overall emissions needed to account for measured atmospheric concentrations of greenhouse gases at various scales. The first type of study can lead to direct improvements to or verification of Inventory estimates. In the past few years, EPA has reviewed, and in many cases, incorporated data from these data sources. The second type of study can provide general indications on potential over- and under-estimates.

One comment on the public review draft suggested that the inventory estimates be compared with an observational analysis from a 2019 Lan et al. study.[80] Lan et al. estimated an average increasing trend of U.S. oil and gas methane emissions of 3.4 percent +/-1.4 percent per year between 2006 and 2015, based on three U.S. measurement sites that were "substantially influenced by O&NG activities." This study did not address the magnitude of emissions. Nationally, in the Inventory, methane emissions from oil and gas decreased by an average of 1 percent per year from 2006 to 2015, largely driven by the natural gas distribution and transmission and storage segments. A key challenge in using these types of studies to assess Inventory results is having a relevant basis for comparison (e.g., the two data sets should have comparable time frames and geographic coverage, and the independent study should assess data from the Inventory and not another data set, such as the Emissions Database for Global Atmospheric Research, or "EDGAR"). In an effort to improve the ability to compare the national-level Inventory with measurement results that may be at other scales, a team at Harvard University along with EPA and other coauthors developed a gridded inventory of U.S. anthropogenic methane emissions with 0.1 degree x 0.1 degree spatial resolution, monthly temporal resolution, and detailed scale-dependent error characterization.[81] The gridded methane inventory is designed to be consistent with the U.S. EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2014* estimates for the year 2012, which presents national totals.[82] An updated version of the gridded inventory is being developed and will improve efforts to compare results of the inventory with atmospheric studies.

As discussed above, refinery emissions are quantified by using the total emissions reported to GHGRP for the refinery emission categories included in Petroleum Systems. Subpart Y has provisions that refineries are not required to report under Subpart Y if their emissions fall below certain thresholds. Each year, a review is conducted to determine whether an adjustment is needed to the Inventory emissions to include emissions from refineries that stopped reporting to the GHGRP. The 2019 GHGRP data indicates that 3 refineries stopped reporting in 2019

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

[80] See <https://agupubs.onlinelibrary.wiley.com/doi/epdf/10.1029/2018GL081731>.

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

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

(i.e., 2018 is the last reported year). Two of the refineries ceased refinery operations permanently and the other was a refinery that discontinued reporting in 2019 without a valid reason. EPA did not adjust the 2019 refinery emissions in the Inventory but will further consider if adjustments are warranted in the future for the refinery that discontinued reporting without a valid reason.

Recalculations Discussion

EPA received information and data related to the emission estimates through GHGRP reporting, the annual Inventory formal public notice periods, stakeholder feedback on updates under consideration, and new studies. In September 2020, EPA released a draft memorandum that discussed changes under consideration to estimate emissions from produced water and requested stakeholder feedback on those changes. EPA then created an updated version of the memorandum to document the methodology implemented in the current Inventory.[83] The EPA memorandum *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2019: Update for Produced Water Emissions* (*Produced Water* memo) is cited below.

EPA thoroughly evaluated relevant information available and made an update to include an estimate for produced water emissions, discussed in detail below. In addition, certain sources did not undergo methodological updates, but CH_4 and/or CO_2 emissions changed by greater than 0.05 MMT CO_2 Eq., comparing the previous estimate for 2018 to the current (recalculated) estimate for 2018. For the sources without methodological updates, the emissions changes were mostly due to GHGRP data submission revisions and well count updates Enverus updates. These sources are also discussed below and include hydraulically fractured oil well completions, associated gas flaring, miscellaneous production flaring, production storage tanks, pneumatic controllers, chemical injection pumps, oil wellheads (leaks), and gas engines.

The combined impact of revisions to 2018 petroleum systems CH_4 emission estimates, compared to the previous Inventory, is an increase from 36.2 to 39.4 MMT CO_2 Eq. (3.2 MMT CO_2 Eq., or 9 percent). The recalculations resulted in an average increase in CH_4 emission estimates across the 1990 through 2018 time series, compared to the previous Inventory, of 1.1 MMT CO_2 Eq., or 3 percent, with the largest increase being in the estimate for 1990 (2.8 MMT CO_2 Eq. or 6 percent) primarily due to inclusion of produced water estimates.

The combined impact of revisions to 2018 petroleum systems CO_2 emission estimates, compared to the previous Inventory, is an increase from 36.8 to 37.1 MMT CO_2 (0.3 MMT CO_2, or less than 1 percent). The recalculations resulted in an average decrease in emission estimates across the 1990 through 2018 time series, compared to the previous Inventory, of 0.1 MMT CO_2 Eq., or 0.4 percent with the largest changes being for 2016 (1.1 MMT CO_2 or 5 percent) primarily due to the recalculations for flaring from tanks.

The combined impact of revisions to 2018 petroleum systems N_2O emission estimates, compared to the previous Inventory, is a decrease of 0.03 MMT CO_2, Eq. or 41 percent. The emission changes were primarily driven by reduction in flaring emissions from storage tanks and miscellaneous production flaring due to GHGRP data submission revisions. The recalculations resulted in an average decrease in emission estimates across the 1990 through 2018 time series, compared to the previous Inventory, of 0.001 MMT CO_2 Eq., or 2 percent.

In Table 3-45 and Table 3-46 below are categories in Petroleum Systems with updated methodologies or with recalculations resulting in a change of greater than 0.05 MMT CO_2 Eq., comparing the previous estimate for 2018 to the current (recalculated) estimate for 2018. For more information, please see the discussion below.

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

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

Segment/Source	*Previous Estimate Year 2018, 2020 Inventory*	Current Estimate Year 2018, 2021 Inventory	Current Estimate Year 2019, 2021 Inventory
Exploration	***2.8***	**2.9**	**2.1**
HF Oil Well Completions	*2.7*	2.9	2.1
Production	***30.3***	**30.5**	**40.2**
Produced Water	*NE*	0.0	0.0
Tanks	*6.4*	6.3	6.1
Associated Gas Flaring	*19.0*	19.3	25.4
Miscellaneous Flaring	*4.2*	4.2	7.9
Transportation	***+***	**+**	**+**
Refining	***3.7***	**3.7**	**5.0**
Petroleum Systems Total	***36.8***	**37.1**	**47.3**

+ Does not exceed 0.05 MMT CO_2.
NE (Not Estimated)

Table 3-46: Recalculations of CH_4 in Petroleum Systems (MMT CO_2 Eq.)

Segment/Source	*Previous Estimate Year 2018, 2020 Inventory*	Current Estimate Year 2018, 2021 Inventory	Current Estimate Year 2019, 2021 Inventory
Exploration	***0.4***	**0.4**	**0.3**
HF Oil Well Completions	*0.3*	0.4	0.2
Production	***34.9***	**35.9**	**37.7**
Produced Water	*NE*	2.1	2.1
Pneumatic Controllers	*18.4*	17.3	17.5
Associated Gas Flaring	*1.3*	1.7	2.0
Miscellaneous Flaring	*0.4*	0.3	0.6
Chemical InjectionPumps	*2.0*	1.9	1.9
Oil Wellheads (Leaks)	*1.5*	1.4	1.4
Gas Engines	*2.3*	2.4	2.4
Transportation	***0.2***	**0.2**	**0.2**
Refining	***0.8***	**0.8**	**0.9**
Petroleum Systems Total	***36.2***	**39.4**	**41.2**

NE (Not Estimated)

Exploration

HF Oil Well Completions (Recalculation with Updated Data)

HF oil well completion CO_2 emissions decreased by an average of 1 percent across the time series and increased by 5 percent in 2018, compared the to the previous Inventory. The emissions changes were due to GHGRP data submission revisions.

Table 3-47: HF Oil Well Completions National CO_2 Emissions (kt CO_2)

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	88	140	439	248	394	574	795
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	1,494	926	1,270	2,300	1,283
Total Emissions	**91**	**144**	**1,935**	**1,174**	**1,664**	**2,874**	**2,078**

Previous Estimate	*92*		*143*		*1,966*	*1,192*	*1,529*	*2,730*	*NA*

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

Production

Produced Water (Methodological Update)

EPA developed a new calculation methodology to estimate produced water emissions from oil wells. Previous Inventories did not include emissions from produced water from oil wells. EPA's considerations for this source are documented in the *Produced Water* Memo.[84] Produced water quantities (i.e., bbl) were obtained for 36 oil-producing states as described below:

- Produced water quantities for 1990-2019 were obtained using DrillingInfo and Prism datasets from Enverus for 29 states (i.e., AK, AL, AR, AZ, CA, CO, FL, ID, KY, LA, MD, MI, MN, MO, MS, MT, NC, ND, NE, NM, NV, NY, OR, SD, TN, TX, UT, VA, and WY) (Enverus 2021). Linear interpolation was used to correct an obviously inaccurate near-zero produced water quantity value in Colorado for 1998.
- For four additional states, produced water quantities for 1990-2018 were obtained from state agency websites – KS (Kansas Department of Health and Environment 2020), OH (Ohio Environmental Protection Agency 2020), OK (Oklahoma Department of Environmental Quality 2020), and PA (Pennsylvania Department of Environmental Protection 2020). Produced water quantities for 2018 were used as proxy data for 2019 for these four states.
- Produced water quantities for 1990-2018 were estimated for three states (IL, IN, and WV) using state-level produced water production ratios for oil wells. Well-level produced water data for oil wells for 2011 were obtained from the DrillingInfo dataset (Enverus 2021) and oil production data were obtained from state agency websites – IL (Illinois Office of Oil and Gas Resource Management 2020), IN (Indiana Division of Oil & Gas 2020), and WV (West Virginia Department of Environmental Protection 2020). Using these well-level produced water data and the oil production data, production ratios were developed for oil wells in each state. These production ratios were then applied to annual state-level oil production data (2000-2018) from EIA (EIA 2020). Produced water quantities for 2018 were used as proxy data for 2019 for these three states.

Based upon findings of the CenSARA emissions inventory (CenSARA 2012), EPA assumed that 73 percent of the produced water was from low pressure oil wells (i.e., wells requiring artificial lifts) and that 27 percent of the produced water was from regular pressure oil wells (i.e., wells not requiring artificial lifts).. EPA applied emission factors unique to low pressure and regular pressure oil wells, obtained from the Production Module of the 2017 Oil and Gas Tool. Produced water CH_4 emissions average 73,000 mt CH_4, over the 1990 to 2019 time series.

EPA received feedback on this update through its September 2020 memo and through the public review draft of the inventory.

A stakeholder indicated that the typical practice is to route produced water to a tank battery, once it reaches the surface and has been separated from the oil and gas. A stakeholder requested that data from the latest 2017 Ground Water Protection Council produced water management practices survey be used to determine the percent of produced water that is stored in tanks. The stakeholder indicated that approximately 16 percent of produced water has the potential of being stored in a tank battery that could potentially flash (based on the 2012 Ground Water Protection Council produced water management practices survey). After further assessment of the 2012 and 2017 water management practice surveys, EPA has maintained the assumption that all produced water goes through tanks and emissions are flashed, consistent with the approach used for the public review draft of the Inventory.

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

A stakeholder commented that current regulations under 40 CFR 60 subpart OOOOa require that certain storage vessels route emission vapors to a recovery device, flare, or other control device. EPA currently does not have specific data to address the use of controls on produced water tanks but will continue to assess this issue in future inventories should additional data become available.

Table 3-48: Produced Water National CH_4 Emissions (Metric Tons CH_4)

Source	1990		2005		2015	2016	2017	2018	2019
Low Pressure Oil Wells	20,292		13,794		18,276	17,142	17,446	18,368	18,794
Regular Pressure Oil Wells	71,186		48,390		64,115	60,136	61,273	64,438	65,931
Total	**91,478**		**62,184**		**82,392**	**77,278**	**78,739**	**82,806**	**84,726**
Previous Estimate	*NA*		*NA*		*NA*	*NA*	*NA*	*NA*	*NA*

NA (Not Applicable)

Tanks (Recalculation with Updated Data)

Tank CO_2 emissions estimates increased by an average of 2 percent across the 1990 to 2018 time series and decreased by 1 percent in 2018, compared to the previous inventory. The emission changes were due to GHGRP data submission revisions.

Table 3-49: Tanks National CO_2 Emissions (kt CO_2)

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**
Previous Estimate	*46*		*2,641*		*7,584*	*5,913*	*4,413*	*6,369*	*NA*

NA (Not Applicable)

Pneumatic Controllers (Recalculation with Updated Data)

Pneumatic controller CH_4 emission estimates decreased by an average of 3 percent across the 1990 to 2018 time series and decreased by 6 percent in 2018, compared to the previous Inventory. The emission changes were due to GHGRP data submission revisions and updated Enverus well counts.

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

Source	1990		2005		2015	2016	2017	2018	2019
High Bleed	741,469		401,564		73,505	77,866	57,020	45,304	49,775
Low Bleed	50,606		42,080		23,868	16,358	18,283	28,496	34,092
Intermittent Bleed	0		229,126		652,946	690,799	724,193	620,175	615,621
Total Emissions	**792,075**		**672,769**		**750,320**	**785,023**	**799,496**	**693,976**	**699,488**
Previous Estimate	*772,311*		*704,401*		*789,484*	*822,989*	*850,624*	*734,824*	*NA*

NA (Not Applicable)

Associated Gas Flaring (Recalculation with Updated Data)

Associated gas flaring CO_2 emission estimates increased by an average of 1 percent across the time series and increased by 2 percent in 2018 in the current Inventory, compared to the previous Inventory. The emission changes were due to GHGRP data submission revisions.

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

Source	1990		2005		2015	2016	2017	2018	2019
220 - Gulf Coast Basin (LA, TX)	227		121		672	404	744	643	584
360 - Anadarko Basin	108		66		242	1	64	82	18
395 - Williston Basin	987		1,263		8,567	6,091	6,908	11,140	16,572
430 - Permian Basin	2,983		2,056		4,468	2,261	3,209	6,782	7,161
"Other" Basins	935		505		548	324	387	641	1,021
Total Emissions	**5,241**		**4,011**		**14,498**	**9,081**	**11,313**	**19,287**	**25,356**
220 - Gulf Coast Basin (LA, TX)	*234*		*127*		*673*	*404*	*740*	*686*	*NA*
360 - Anadarko Basin	*108*		*65*		*238*	*2*	*57*	*37*	*NA*
395 - Williston Basin	*966*		*1,239*		*8,412*	*5,838*	*6,530*	*10,132*	*NA*
430 - Permian Basin	*2,983*		*2,046*		*4,443*	*2,246*	*3,148*	*7,249*	*NA*
"Other" Basins	*925*		*499*		*544*	*326*	*414*	*876*	*NA*
Previous Estimate	*5,217*		*3,977*		*14,311*	*8,815*	*10,889*	*18,980*	*NA*

NA (Not Applicable)

Associated gas flaring CH_4 emission estimates increased by an average of 2 percent across the time series in the current Inventory, compared to the previous inventory. The CH_4 estimates increased by 27 percent in 2018, primarily due to Williston Basin data. The emission changes were due to GHGRP data submission revisions.

Table 3-52 Associated Gas Flaring National CH_4 Emissions (Metric Tons CH_4)

Source	1990		2005		2015	2016	2017	2018	2019
220 - Gulf Coast Basin (LA, TX)	896		479		2,654	1,572	2,936	2,448	2,626
360 - Anadarko Basin	472		288		1,056	4	277	358	87
395 - Williston Basin	2,931		3,750		25,437	16,948	20,707	37,754	48,453
430 - Permian Basin	11,815		8,143		17,696	8,972	13,189	25,511	27,016
"Other" Basins	4,328		2,335		2,538	1,193	1,290	1,932	3,614
Total Emissions	**20,441**		**14,995**		**49,380**	**28,689**	**38,399**	**68,004**	**81,797**
220 - Gulf Coast Basin (LA, TX)	*922*		*500*		*2,659*	*1,572*	*2,918*	*2,779*	*NA*
360 - Anadarko Basin	*471*		*285*		*1,038*	*7*	*252*	*190*	*NA*
395 - Williston Basin	*2,874*		*3,686*		*25,020*	*16,151*	*20,130*	*26,011*	*NA*
430 - Permian Basin	*11,816*		*8,104*		*17,596*	*8,913*	*12,974*	*22,597*	*NA*
"Other" Basins	*4,274*		*2,306*		*2,514*	*1,196*	*1,388*	*1,862*	*NA*
Previous Estimate	*20,357*		*14,881*		*48,826*	*27,839*	*37,662*	*53,438*	*NA*

NA (Not Applicable)

Miscellaneous Production Flaring (Recalculation with Updated Data)

Miscellaneous production flaring CH_4 emission estimates decreased by 27 percent in 2018 and decreased by an average of 4 percent for other years of the time series, compared to the previous Inventory. The 2018 decrease was primarily due to recalculations in the Permian and Gulf Coast basins, where GHGRP data showed lower CH_4 flaring emissions, by 47 and 18 percent, respectively. The emission changes were due to GHGRP data submission revisions.

Table 3-53: Miscellaneous Production Flaring National CH_4 Emissions (Metric Tons CH_4)

Source	1990		2005		2015	2016	2017	2018	2019
220 - Gulf Coast Basin (LA, TX)	0		410		4,021	1,979	2,179	1,951	2,554
395 - Williston Basin	0		182		2,184	854	1,618	3,045	3,904
430 - Permian Basin	0		807		3,103	2,812	5,055	4,449	14,151
Other Basins	0		1,316		2,806	1,455	1,960	1,891	1,847
Total Emissions	**0**		**2,715**		**12,114**	**7,101**	**10,812**	**11,336**	**22,457**
220 - Gulf Coast Basin (LA, TX)	*0*		*424*		*3,985*	*1,979*	*2,164*	*2,370*	*NA*
395 - Williston Basin	*0*		*191*		*2,293*	*888*	*1,603*	*2,947*	*NA*
430 - Permian Basin	*0*		*805*		*3,091*	*2,794*	*5,024*	*8,406*	*NA*
Other Basins	*0*		*1,440*		*3,074*	*1,452*	*2,018*	*1,812*	*NA*
Previous Total Estimate	*0*		*2,859*		*12,443*	*7,113*	*10,810*	*15,536*	*NA*

NA (Not Applicable)

Miscellaneous production flaring CO_2 emission estimates decreased by 1 percent in 2018 and decreased by less than 0.5 percent for other years of the time series, compared to the previous Inventory. The 2018 decrease was primarily due to recalculations of CO_2 from flaring in the Gulf Coast Basin, where GHGRP data showed lower CO_2 emissions from flaring, by 16 percent. The emission changes were due to GHGRP data submission revisions.

Table 3-54: Miscellaneous Production Flaring National CO_2 Emissions (kt CO_2)

Source	1990		2005		2015	2016	2017	2018	2019
220 - Gulf Coast Basin (LA, TX)	0		102		1,004	497	526	577	625
395 - Williston Basin	0		73		873	304	537	1,706	2,934
430 - Permian Basin	0		215		828	799	1,433	1,244	3,701
Other Basins	0		408		870	593	568	640	689
Total Emissions	**0**		**799**		**3,575**	**2,192**	**3,063**	**4,167**	**7,949**
220 - Gulf Coast Basin (LA, TX)	*0*		*106*		*997*	*497*	*526*	*687*	*NA*
395 - Williston Basin	*0*		*73*		*882*	*315*	*531*	*1,653*	*NA*
430 - Permian Basin	*0*		*215*		*825*	*794*	*1,424*	*1,183*	*NA*
Other Basins	*0*		*407*		*870*	*592*	*585*	*703*	*NA*
Previous Total Estimate	*0*		*801*		*3,573*	*2,198*	*3,066*	*4,226*	*NA*

NA (Not Applicable)

Chemical Injection Pumps (Recalculation with Updated Data)

Chemical injection pump CH_4 emission estimates decreased by an average of 4 percent across the time series and decreased by 6 percent in 2018, compared to the previous Inventory. The emission changes were due to updated Enverus well counts.

Table 3-55: Chemical Injection Pump National CH_4 Emissions (Metric Tons CH_4)

Source	1990		2005		2015	2016	2017	2018	2019
Chemical Injection Pump	50,806		64,259		81,103	78,351	77,061	76,014	75,182
Previous Estimate	*49,368*		*68,097*		*86,529*	*83,705*	*82,180*	*81,294*	*NA*

NA (Not Applicable)

Oil Wellheads (Recalculation with Updated Data)

Oil wellhead CH_4 emission estimates decreased by an average of 8 percent across the time series and decreased by 6 percent in 2018, compared to the previous Inventory. The emission changes were due to updated Enverus well counts.

Table 3-56: Oil Wellhead National CH_4 Emissions (Metric Tons CH_4)

Source	1990		2005		2015	2016	2017	2018	2019
Oil Wellheads (heavy crude)	32		28		35	34	34	33	33
Oil Wellheads (light crude)	55,064		48,648		61,163	59,088	58,115	57,326	56,699
Total Emissions	**55,096**		**48,676**		**61,199**	**59,122**	**58,149**	**57,359**	**56,732**
Previous Estimate	*61,144*		*52,504*		*65,294*	*63,162*	*62,011*	*61,343*	*NA*

NA (Not Applicable)

Gas Engines (Recalculation with Updated Data)

Gas engine (combustion slip) CH_4 emission estimates increased by an average of 4 percent across the time series and increased by 5 percent in 2018, compared to the previous Inventory. The emission changes were due to updated Enverus well counts. Even though the well counts have decreased across the time-series, the 2018 gas engine estimates are calculated using the ratio of 2018 to 1993 well counts. Since the 1993 well counts show a larger decrease (-12%) compared to the 2018 well counts (-6%), the gas engine estimates increased.

Table 3-57: Gas Engine National CH_4 Emissions (Metric Tons CH_4)

Source	1990		2005		2015	2016	2017	2018	2019
Total Gas Engine Emissions	87,854		73,659		98,896	94,771	94,311	96,338	97,828
Previous Estimate	*85,744*		*69,999*		*93,414*	*89,565*	*89,063*	*91,459*	*NA*

NA (Not Applicable)

Well Counts (Recalculation with Updated Data)

EPA uses annual producing oil well counts as an input for estimates of emissions from multiple sources in the Inventory, including exploration well testing, pneumatic controllers, chemical injection pumps, well workovers, and equipment leaks. Annual well count data are obtained from Enverus for the entire time series during each Inventory cycle, and a new data processing methodology was implemented this year due to a restructuring of the Enverus well count data (Enverus 2021). Due to of the data restructuring and the new processing methodology, annual well counts decreased by an average of 8 percent across the 1990-2018 time series and decreased by 6 percent in 2018, compared to the previous Inventory.

Table 3-58: National Oil Well Counts

Source	1990		2005		2015	2016	2017	2018	2019
Oil Wells	506,730		447,683		562,857	543,759	534,806	527,544	521,771
Previous Estimate	*562,356*		*482,887*		*600,519*	*580,917*	*570,331*	*564,186*	*NA*

NA (Not Applicable)

In December 2020, EIA released an updated time series of national oil and gas well counts (covering 2000 through 2018). EIA estimates 969,136 total producing wells for year 2019. EPA's total well count for this year is 939,637. EPA's well counts are generally lower than EIA's (e.g., around 3 percent lower in 2019). EIA's well counts include side tracks (i.e., secondary wellbore away from original wellbore in order to bypass unusable formation, explore nearby formations, or other reasons), completions, and recompletions, and therefore are expected to be higher than EPA's which include only producing wells. EPA and EIA use a different threshold for distinguishing between oil versus gas (EIA uses 6 mcf/bbl, while EPA uses 100 mcf/bbl), which results in EIA having a lower fraction of oil wells (e.g., 44 percent versus EPA's 56 percent in 2019) and a higher fraction of gas wells (e.g., 56 percent versus EPA's 44 percent in 2019) than EPA.

Transportation

Recalculations for the transportation segment have resulted in an average increase in calculated CH_4 and CO_2 emissions over the time series from this segment of less than 0.02 percent, compared to the previous Inventory.

Refining

Recalculations due to resubmitted GHGRP data in the refining segment have resulted in an average increase in calculated CH_4 emissions over the time series from this segment of 0.1 percent and an average increase in calculated CO_2 emissions over the time series of less than 0.01 percent, compared to the previous Inventory.

Planned Improvements

Mud Degassing

As part of the stakeholder process for the current (1990 to 2019) Inventory, EPA developed draft CH_4 emission estimates for mud degassing in the onshore exploration segment. To date, the Inventory has not included emissions from onshore exploration mud degassing. EPA's considerations for this source are documented in the EPA memorandum *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2019: Update Under Consideration for Mud Degassing Emissions* (*Mud Degassing* Memo).[85] EPA estimated emissions using CH_4 emission factors from EPA (EPA 1977) and the count of wells drilled from Enverus DrillingInfo data (Enverus DrillingInfo 2019). To calculate emissions per well drilled, EPA incorporated an estimate of 26 days as an average drilling duration and 61.2 percent (by weight) as the default CH_4 content of associated gas. EPA developed national estimates for two different scenarios: 1) EPA assumed 80 percent of drilling operations were performed using water-based muds and the remaining 20 percent used oil-based muds; and 2) EPA assumed 100 percent of drilling operations were performed using water-based muds. Mud degassing CH_4 emissions averaged 107 kt over the time series for scenario 1 and 126 kt for scenario 2, or around 3 MMT CO_2 Eq. This update would increase emissions from the exploration segment but would have a small impact on overall CH_4 emissions from petroleum systems.

EPA notes that estimates for mud degassing using similar assumptions are included in several other bottom-up inventories for greenhouse gases and other gases, including New York state and the NEI.

EPA received feedback on this update through its September 2020 memo and through the public review draft of the Inventory. A stakeholder indicated the 12 inch diameter borehole and 25 percent formation porosity assumptions used in developing the CH_4 emission factor for water-based muds are outdated and recommended that an 8 inch borehole diameter and 10 percent porosity should be considered in developing the CH_4 EF. A stakeholder commented that current onshore practices are to drill with balanced or slightly over-balanced mud systems that keep gas from being entrained in the drilling mud and that mud degassing systems are rarely needed or used. A stakeholder also indicated that mainly oil-based muds are used for horizontal/lateral drilling and water-based muds are more frequently used for vertical drilling.

Additionally, EPA also received comments on the average drilling duration used in developing the draft estimates for onshore mud degassing. A stakeholder commentstated that EPA should only consider the duration the drill spends in the producing formation. Another comment indicated that EPA's average drilling duration assumption of 26 days per well is high and presented 2 examples – a Marcellus well takes 10 days to drill with 2-3 days in the producing formation; and the drilling duration in the Fayetteville shale dropped from 20 days in 2007 to 11 days in 2009. EPA's average drilling duration assumption of 26 days per well is comparable to average drilling duration

[85] 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>.

developed from other inventories (New York – 24 days/well and CenSARA – 22 days/well). Refer to the *Mud Degassing* memo for further details.

EPA continues to seek feedback on average total drilling days and drilling days in the producing formation, CH_4 content of the gas, and the effect of balanced and over-balanced mud degassing systems. EPA will further assess the average drilling duration using updated Enverus data. Additionally, EPA is considering developing CO_2 estimates for onshore production mud degassing using the CH_4 estimates and a ratio of CO_2-to-CH_4.

Table 3-59: Draft Mud Degassing National CH_4 Emissions—Not Included in Totals (Metric Tons CH_4)

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

Upcoming Data, and Additional Data that Could Inform the Inventory

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

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

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

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

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

Box 3-6: Carbon Dioxide Transport, Injection, and Geological Storage

Carbon dioxide is produced, captured, transported, and used for Enhanced Oil Recovery (EOR) as well as commercial and non-EOR industrial applications, or is stored geologically. This CO_2 is produced from both naturally-occurring CO_2 reservoirs and from industrial sources such as natural gas processing plants and ammonia plants. In the Inventory, emissions of CO_2 from naturally-occuring CO_2 reservoirs are estimated based on the specific application.

In the Inventory, CO_2 that is used in non-EOR industrial and commercial applications (e.g., food processing, chemical production) is assumed to be emitted to the atmosphere during its industrial use. These emissions are discussed in the Carbon Dioxide Consumption section, 4.15.

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

IPCC includes methodological guidance to estimate emissions from the capture, transport, injection, and geological storage of CO_2. The methodology is based on the principle that the carbon capture and storage system should be handled in a complete and consistent manner across the entire Energy sector. The approach accounts for CO_2 captured at natural and industrial sites as well as emissions from capture, transport, and use. For storage specifically, a Tier 3 methodology is outlined for estimating and reporting emissions based on site-specific evaluations. However, IPCC (IPCC 2006) notes that if a national regulatory process exists, emissions information available through that process may support development of CO_2 emission estimates for geologic storage.

In the United States, facilities that produce CO_2 for various end-use applications (including capture facilities such as acid gas removal plants and ammonia plants), importers of CO_2, exporters of CO_2, facilities that conduct geologic sequestration of CO_2, and facilities that inject CO_2 underground, are required to report greenhouse gas data annually to EPA through its GHGRP. Facilities reporting geologic sequestration of CO_2 to the GHGRP develop and implement an EPA-approved site-specific monitoring, reporting and verification plan, and report the amount of CO_2 sequestered using a mass balance approach.

GHGRP data relevant for this inventory estimate consists of national-level annual quantities of CO_2 captured and extracted for EOR applications for 2010 to 2019 and data reported for geologic sequestration from 2016 to 2019.

The amount of CO_2 captured and extracted from natural and industrial sites for EOR applications in 2019 is 52,100 kt (52.1 MMT CO_2 Eq.) (see 6). The quantity of CO_2 captured and extracted is noted here for information purposes only; CO_2 captured and extracted from industrial and commercial processes is generally assumed to be emitted and included in emissions totals from those processes.

Table 3-60: Quantity of CO_2 Captured and Extracted for EOR Operations (kt CO_2)

Stage	2015	2016	2017	2018	2019
Total CO_2 Captured and Extracted Stage	54,000	46,700	49,600	48,400	52,100

Several facilities are reporting under GHGRP subpart RR (Geologic Sequestration of Carbon Dioxide). See Table 3-61 for the number of facilities reporting under subpart RR, the reported CO_2 sequestered in subsurface geologic formations in each year, and of the quantity of CO_2 emitted from equipment leaks in each year. The quantity of CO_2 sequestered and emitted is noted here for information purposes only; EPA is considering updates to its approach in the Inventory for this source for future Inventories.

Table 3-61: Geologic Sequestration Information Reported Under GHGRP Subpart RR

Stage	2015	2016	2017	2018	2019
Number of Reporting Facilities	NA	1	3	5	5
Reported Annual CO_2 Sequestered (kt)	NA	3,091	5,958	7,662	8,332
Reported Annual CO_2 Emissions from Equipment Leaks (kt)	NA	10	10	11	16

3.7 Natural Gas Systems (CRF Source Category 1B2b)

The U.S. natural gas system encompasses hundreds of thousands of wells, hundreds of processing facilities, and over a million miles of transmission and distribution pipelines. This IPCC category (1B2b) is for fugitive emissions, which per IPCC include emissions from leaks, venting, and flaring. Total greenhouse gas emissions (CH_4, CO_2, and N_2O) from natural gas systems in 2019 were 194.9 MMT CO_2 Eq., a decrease of 11 percent from 1990, primarily due to decreases in CH_4 emissions, and an increase of 5 percent from 2018, primarily due to increases in CH_4 emissions. From 2009, emissions increased by 6 percent, primarily due to increases in CO_2 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 (194.9 MMT CO_2 Eq.), 81 percent are CH_4 emissions (157.6 MMT CO_2 Eq.), 19 percent are CO_2 emissions (37.2 MMT), and less than 0.01 percent are N_2O emissions (0.01 MMT CO_2 Eq.).

Overall, natural gas systems emitted 157.6 MMT CO_2 Eq. (6,305 kt CH_4) of CH_4 in 2019, a 16 percent decrease compared to 1990 emissions, and 3 percent increase compared to 2018 emissions (see Table 3-63 and Table 3-64). For non-combustion CO_2, a total of 37.2 MMT CO_2 Eq. (37,234 kt) was emitted in 2019, a 16 percent increase compared to 1990 emissions, and a 10 percent increase compared to 2018 levels. The 2019 N_2O emissions were estimated to be 0.01 MMT CO_2 Eq. (0.04 kt N_2O), a 123 percent increase compared to 1990 emissions, and a 1 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 CH_4 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 CH_4 emissions of 59 percent (with onshore production emissions increasing 44 percent, offshore production emissions decreasing 82 percent, and gathering and boosting [G&B] emissions increasing 121 percent). The 1990 to 2019 increase in CO_2 emissions is primarily due to an increase in CO_2 emissions in the production segment, where emissions from flaring have increased over time.

Methane and CO_2 emissions from natural gas systems include those resulting from normal operations, routine maintenance, and system upsets. Emissions from normal operations include natural gas engine and turbine uncombusted exhaust, flaring, and leak emissions from system components. Routine maintenance emissions originate from pipelines, equipment, and wells during repair and maintenance activities. Pressure surge relief systems and accidents can lead to system upset emissions. Emissions of N_2O from flaring activities are included in the Inventory, with most of the emissions occurring in the processing and production segments. Note, CO_2 emissions exclude all combustion emissions (e.g., engine combustion) except for flaring CO_2 emissions. All combustion CO_2 emissions (except for flaring) are accounted for in Section 3.1 – CO_2 from Fossil Fuel Combustion.

Each year, some estimates in the Inventory are recalculated with improved methods and/or data. These improvements are implemented consistently across the previous Inventory's time series (i.e., 1990 to 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
- Updates to well counts using the most recent data from Enverus
- Recalculations due to GHGRP submission revisions

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

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

Exploration. Exploration includes well drilling, testing, and completions. Emissions from exploration accounted for less than 1 percent of CH_4 emissions and of CO_2 emissions from natural gas systems in 2019. Well completions accounted for approximately 95 percent of CH_4 emissions from the exploration segment in 2019, with the rest resulting from well testing and drilling. Flaring emissions account for most of the CO_2 emissions. Methane emissions from exploration decreased by 87 percent from 1990 to 2019, with the largest decreases coming from hydraulically fractured gas well completions without reduced emissions completions (RECs). Methane emissions decreased 36 percent from 2018 to 2019 due to decreases in emissions from hydraulically fractured well completions with RECs and venting. Methane emissions were highest from 2005 to 2008. Carbon dioxide emissions from exploration decreased by 44 percent from 1990 to 2019 and decreased 34 percent from 2018 to 2019 due to decreases in flaring. Carbon dioxide emissions were highest from 2006 to 2008. Nitrous oxide emissions decreased 73 percent from 1990 to 2019 and decreased 95 percent from 2018 to 2019.

Production (including gathering and boosting). In the production segment, wells are used to withdraw raw gas from underground formations. Emissions arise from the wells themselves, and from well-site equipment and activities such as pneumatic controllers, tanks and separators, and liquids unloading. Gathering and boosting emission sources are included within the production sector. The gathering and boosting sources include gathering and boosting stations (with multiple emission sources on site) and gathering pipelines. The gathering and boosting stations receive natural gas from production sites and transfer it, via gathering pipelines, to transmission pipelines or processing facilities (custody transfer points are typically used to segregate sources between each segment). Boosting processes include compression, dehydration, and transport of gas to a processing facility or pipeline. Emissions from production (including gathering and boosting) accounted for 59 percent of CH_4 emissions and 29 percent of CO_2 emissions from natural gas systems in 2019. Emissions from gathering and boosting and pneumatic controllers in onshore production accounted for most of the production segment CH_4 emissions in 2019. Within gathering and boosting, the largest sources of CH_4 are compressor exhaust slip, compressor venting and leaks, and tanks. Flaring emissions account for most of the CO_2 emissions from production, with the highest emissions coming from flare stacks at gathering stations, miscellaneous onshore production flaring, and tank flaring. Methane emissions from production increased by 59 percent from 1990 to 2019, due primarily to increases in emissions from pneumatic controllers (due to an increase in the number of controllers, particularly in the number of intermittent bleed controllers) and increases in emissions from compressor exhaust slip in gathering and boosting. Methane emissions increased 3 percent from 2018 to 2019 due to increases in the number of intermittent bleed controllers and increases in emissions from tanks in gathering and boosting. Carbon dioxide emissions from production increased by approximately a factor of 3.6 from 1990 to 2019 due to increases in emissions at flare stacks in gathering and boosting and miscellaneous onshore production flaring, and increased 11 percent from 2018 to 2019 due primarily to increases in emissions from flare stacks and acid gas removal in gathering and boosting. Nitrous oxide emissions increased 28 percent from 1990 to 2019 and increased 10 percent from 2018 to 2019. The increase in N_2O emissions from 1990 to 2019 and from 2018 to 2019 is primarily due to increase in emissions from flare stacks at gathering and boosting stations.

Processing. In the processing segment, natural gas liquids and various other constituents from the raw gas are removed, resulting in "pipeline quality" gas, which is injected into the transmission system. Methane emissions from compressors, including compressor seals, are the primary emission source from this stage. Most of the CO_2 emissions come from acid gas removal (AGR) units, which are designed to remove CO_2 from natural gas. Processing plants accounted for 8 percent of CH_4 emissions and 67 percent of CO_2 emissions from natural gas systems. Methane emissions from processing decreased by 42 percent from 1990 to 2019 as emissions from compressors (leaks and venting) and equipment leaks decreased; and increased 3 percent from 2018 to 2019 due to increased emissions from gas engines. Carbon dioxide emissions from processing decreased by 13 percent from 1990 to 2019, due to a decrease in AGR emissions, and increased 7 percent from 2018 to 2019 due to increased emissions from flaring. Nitrous oxide emissions increased 39 percent from 2018 to 2019.

Transmission and Storage. Natural gas transmission involves high pressure, large diameter pipelines that transport gas long distances from field production and processing areas to distribution systems or large volume customers such as power plants or chemical plants. Compressor station facilities are used to move the gas throughout the U.S. transmission system. Leak CH_4 emissions from these compressor stations and venting from pneumatic controllers account for most of the emissions from this stage. Uncombusted compressor engine exhaust and pipeline venting are also sources of CH_4 emissions from transmission. Natural gas is also injected and stored in underground formations, or liquefied and stored in above ground tanks, during periods of low demand (e.g., summer), and withdrawn, processed, and distributed during periods of high demand (e.g., winter). Leak and venting emissions from compressors are the primary contributors to CH_4 emissions from storage. Emissions from liquefied natural gas (LNG) stations and terminals are also calculated under the transmission and storage segment. Methane emissions from the transmission and storage segment accounted for approximately 23 percent of emissions from natural gas systems, while CO_2 emissions from transmission and storage accounted for 3 percent of the CO_2 emissions from natural gas systems. CH_4 emissions from this source decreased by 35 percent from 1990 to 2019 due to reduced compressor station emissions (including emissions from compressors and leaks) and increased 6 percent from 2018 to 2019 due to increased emissions from transmission compressors. CO_2 emissions from transmission and storage were 6.9 times higher in 2019 than in 1990, due to increased emissions from LNG export terminals, and increased by 128 percent from 2018 to 2019, also due to LNG export terminals. The quantity of LNG exported from the U.S. increased by a factor of 35 from 1990 to 2019, and by 68 percent from 2018 to 2019. LNG emissions are about 1 percent of CH_4 and 80 percent of CO_2 emissions from transmission and storage in year 2019. Nitrous oxide emissions from transmission and storage increased by 145 percent from 1990 to 2019 and increased 169 percent from 2018 to 2019.

Distribution. Distribution pipelines take the high-pressure gas from the transmission system at “city gate” stations, reduce the pressure and distribute the gas through primarily underground mains and service lines to individual end users. There were 1,316,689 miles of distribution mains in 2019, an increase of 372,532 miles since 1990 (PHMSA 2020). Distribution system emissions, which accounted for 9 percent of CH_4 emissions from natural gas systems and less than 1 percent of CO_2 emissions, result mainly from leak emissions from pipelines and stations. An increased use of plastic piping, which has lower emissions than other pipe materials, has reduced both CH_4 and CO_2 emissions from this stage, as have station upgrades at metering and regulating (M&R) stations. Distribution system CH_4 emissions in 2019 were 69 percent lower than 1990 levels and 1 percent lower than 2018 emissions. Distribution system CO_2 emissions in 2019 were 69 percent lower than 1990 levels and 1 percent lower than 2018 emissions. Annual CO_2 emissions from this segment are less than 0.1 MMT CO_2 Eq. across the time series.

Total greenhouse gas emissions from the five major segments of natural gas systems are shown in MMT CO_2 Eq. in Table 3-62. Total CH_4 emissions for these same segments of natural gas systems are shown in MMT CO_2 Eq. (Table 3-63) and kt (Table 3-64). Most emission estimates are calculated using a net emission approach. However, a few sources are still calculated with a potential emission approach. Reductions data are applied to those sources that use a potential emissions approach. In recent years 6.3 MMT CO_2 Eq. CH_4 are subtracted from production segment emissions and 6.7 MMT CO_2 Eq. CH_4 are subtracted from the transmission and storage segment to calculate net emissions. More disaggregated information on potential emissions, net emissions, and reductions data is available in Annex 3.6, Methodology for Estimating CH_4 and CO_2 Emissions from Natural Gas Systems.

Table 3-62: Total Greenhouse Gas Emissions (CH_4, CO_2, and N_2O) from Natural Gas Systems (MMT CO_2 Eq.)

Stage	1990		2005		2015	2016	2017	2018	2019
Exploration	4.6		12.0		1.3	0.9	1.7	1.2	0.8
Production	61.8		85.2		96.9	94.1	96.6	100.6	104.7
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	**219.0**		**189.4**		**179.0**	**177.4**	**179.9**	**186.4**	**194.9**

Note: Totals may not sum due to independent rounding.

Table 3-63: CH_4 Emissions from Natural Gas Systems (MMT CO_2 Eq.)[a]

Stage	1990		2005		2015	2016	2017	2018	2019
Exploration[b]	**4.2**		**10.3**		**1.0**	**0.7**	**1.2**	**0.8**	**0.5**
Production	**58.8**		**80.4**		**89.3**	**86.6**	**89.4**	**90.8**	**93.7**

Onshore Production	36.0		54.9		52.1	49.5	50.7	51.7	52.0
Gathering and Boosting[c]	18.5		23.9		36.6	36.3	38.0	38.3	40.9
Offshore Production	4.3		1.8		0.6	0.8	0.7	0.8	0.8
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	**186.9**		**164.2**		**149.8**	**147.3**	**148.7**	**152.5**	**157.6**

Note: Totals may not sum due to independent rounding.

[a] These values represent CH_4 emitted to the atmosphere. CH_4 that is captured, flared, or otherwise controlled (and not emitted to the atmosphere) has been calculated and removed from emission totals.

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

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

Table 3-64: CH_4 Emissions from Natural Gas Systems (kt)[a]

Stage	1990		2005		2015	2016	2017	2018	2019
Exploration[b]	**167**		**412**		**42**	**28**	**49**	**33**	**21**
Production	**2,350**		**3,227**		**3,572**	**3,466**	**3,574**	**3,631**	**3,748**
Onshore Production	1,441		2,197		2,085	1,981	2,026	2,068	2,081
Gathering and Boosting[c]	739		957		1,463	1,453	1,521	1,532	1,636
Offshore Production	170		73		24	32	26	31	31
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	**7,478**		**6,567**		**5,994**	**5,894**	**5,949**	**6,101**	**6,305**

Note: Totals may not sum due to independent rounding.

[a] These values represent CH_4 emitted to the atmosphere. CH_4 that is captured, flared, or otherwise controlled (and not emitted to the atmosphere) has been calculated and removed from emission totals.

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

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

Table 3-65: Non-combustion CO_2 Emissions from Natural Gas Systems (MMT)

Stage	1990		2005		2015	2016	2017	2018	2019
Exploration	0.4		1.7		0.3	0.2	0.4	0.4	0.2
Production	3.0		4.5		7.6	7.5	7.3	9.8	11.0
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**		**29.1**	**30.1**	**31.2**	**33.9**	**37.2**

Note: Totals may not sum due to independent rounding.

+ Does not exceed 0.05 MMT CO_2 Eq.

Table 3-66: Non-combustion CO_2 Emissions from Natural Gas Systems (kt)

Stage	1990		2005		2015	2016	2017	2018	2019
Exploration	421		1,651		282	193	445	355	236
Production	3,048		4,486		7,623	7,482	7,261	9,841	10,951
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	54		30		17	17	17	17	16
Total	**32,042**		**25,179**		**29,127**	**30,054**	**31,200**	**33,885**	**37,234**

Note: Totals may not sum due to independent rounding.

Table 3-67: N_2O Emissions from Natural Gas Systems (Metric Tons CO_2 Eq.)

Stage	1990	2005	2015	2016	2017	2018	2019
Exploration	458	1,348	3,248	115	244	2,267	123
Production	4,359	5,804	9,835	8,892	4,453	5,094	5,591
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	**5,073**	**10,808**	**19,196**	**13,209**	**8,226**	**11,182**	**11,331**

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

Table 3-68: N_2O Emissions from Natural Gas Systems (Metric Tons N_2O)

Stage	1990	2005	2015	2016	2017	2018	2019
Exploration	1.5	4.5	10.9	0.4	0.8	7.6	0.4
Production	14.6	19.5	33.0	29.8	14.9	17.1	18.8
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	NO	NO	NO	NO	NO	NO
Total	**17.0**	**36.3**	**64.4**	**44.3**	**27.6**	**37.5**	**38.0**

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

Methodology

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

This section provides a general overview of the methodology for natural gas system emission estimates in the Inventory, which involves the calculation of CH_4, CO_2, and N_2O emissions for over 100 emissions sources (i.e., equipment types or processes), and then the summation of emissions for each natural gas segment.

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

Emission Factors. Key references for emission factors for CH_4 and CO_2 emissions from the U.S. natural gas industry include a 1996 study published by the Gas Research Institute (GRI) and EPA (GRI/EPA 1996), the EPA's GHGRP (EPA 2020), and others.

The 1996 GRI/EPA study developed over 80 CH_4 emission factors to characterize emissions from the various components within the operating segments of the U.S. natural gas system. The GRI/EPA study was based on a combination of process engineering studies, collection of activity data, and measurements at representative natural gas facilities conducted in the early 1990s. Year-specific natural gas CH_4 compositions are calculated using U.S. Department of Energy’s Energy Information Administration (EIA) annual gross production data for National Energy Modeling System (NEMS) oil and gas supply module regions in conjunction with data from the Gas Technology Institute (GTI, formerly GRI) Unconventional Natural Gas and Gas Composition Databases (GTI 2001). These year-specific CH_4 compositions are applied to emission factors, which therefore may vary from year to year due to slight changes in the CH_4 composition of natural gas for each NEMS region.

GHGRP Subpart W data were used to develop CH_4, CO_2, and N_2O emission factors for many sources in the Inventory. In the exploration and production segments, GHGRP data were used to develop emission factors used for all years of the time series for well testing, gas well completions and workovers with and without hydraulic fracturing, pneumatic controllers and chemical injection pumps, condensate tanks, liquids unloading, miscellaneous flaring, gathering and boosting pipelines, and certain sources at gathering and boosting stations. In the processing segment, for recent years of the times series, GHGRP data were used to develop emission factors for leaks, compressors, flares, dehydrators, and blowdowns/venting. In the transmission and storage segment, GHGRP data were used to develop factors for all years of the time series for LNG stations and terminals and transmission pipeline blowdowns, and for pneumatic controllers for recent years of the times series.

Other data sources used for CH_4 emission factors include Zimmerle et al. (2015) for transmission and storage station leaks and compressors, GSI (2019) for underground storage well leaks, GTI (2009 and 2019) for commercial and industrial meters, Lamb et al. (2015) for recent years for distribution pipelines and meter/regulator stations, Zimmerle et al. (2019) for gathering and boosting stations, and Bureau of Ocean Energy Management (BOEM) reports.

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

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

See Annex 3.6 for more detailed information on the methodology and data used to calculate CH_4, CO_2, and N_2O emissions from natural gas systems.

Activity Data. Activity data were taken from various published data sets, as detailed in Annex 3.6. Key activity data sources include data sets developed and maintained by EPA's GHGRP (EPA 2020); Enverus (Enverus 2020); BOEM; Federal Energy Regulatory Commission (FERC); EIA; the Natural Gas STAR Program annual data; Oil and Gas Journal; and PHMSA.

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

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

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

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

The United States reports data to the UNFCCC using this Inventory report along with Common Reporting Format (CRF) tables. This note is provided for those reviewing the CRF tables: The notation key "IE" is used for CO_2 and CH_4 emissions from venting and flaring in CRF table 1.B.2. Disaggregating flaring and venting estimates across the

Inventory would involve the application of assumptions and could result in inconsistent reporting and, potentially, decreased transparency. Data availability varies across segments within oil and gas activities systems, and emission factor data available for activities that include flaring can include emissions from multiple sources (flaring, venting and leaks).

Uncertainty and Time-Series Consistency

EPA has conducted a quantitative uncertainty analysis using the IPCC Approach 2 methodology (Monte Carlo Simulation technique) to characterize the uncertainty for natural gas systems. For more information on the approach, please see the memorandum *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2016: Natural Gas and Petroleum Systems Uncertainty Estimates (2018 Uncertainty Memo).*[86]

EPA used Microsoft Excel's @RISK add-in tool to estimate the 95 percent confidence bound around CH_4 and CO_2 emissions from natural gas systems for the current Inventory. Uncertainty estimates for N_2O were not developed given the minor contribution of N_2O to emission totals. For the CH_4 uncertainty analysis, EPA focused on the 14 highest-emitting sources for the year 2019, which together emitted 75 percent of methane from natural gas systems in 2019, and extrapolated the estimated uncertainty for the remaining sources. Uncertainty was not previously estimated specifically for CO_2 emissions, instead the uncertainty bounds calculated for CH_4 were applied to CO_2 emissions estimates. As part of the stakeholder process for the current Inventory, EPA developed an update to the uncertainty analysis for CO_2. The update is documented in the memorandum, *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2019: Update for Natural Gas and Petroleum Systems CO_2 Uncertainty Estimates.*[87] EPA ultimately applied the same approach as was developed for CH_4. For the CO_2 uncertainty analysis, EPA focused on the 3 highest-emitting sources for the year 2018 (from the previous 1990-2018 Inventory), which together emitted 82 percent of CO_2 from natural gas systems in 2018, and extrapolated the estimated uncertainty for the remaining sources. The CO_2 uncertainty calculations were developed as part of the stakeholder process and were based on the previous 1990-2018 Inventory; as a result, the uncertainty results from last year’s Inventory for year 2018 are applied for this year’s uncertainty analysis. In future years, the CO_2 uncertainty bounds will be calculated using the most recent Inventory data. The @RISK add-in provides for the specification of probability density functions (PDFs) for key variables within a computational structure that mirrors the calculation of the inventory estimate. The IPCC guidance notes that in using this method, "some uncertainties that are not addressed by statistical means may exist, including those arising from omissions or double counting, or other conceptual errors, or from incomplete understanding of the processes that may lead to inaccuracies in estimates developed from models." The uncertainty bounds reported below only reflect those uncertainties that EPA has been able to quantify and do not incorporate considerations such as modeling uncertainty, data representativeness, measurement errors, misreporting or misclassification. The understanding of the uncertainty of emission estimates for this category evolves and improves as the underlying methodologies and datasets improve.

The results presented below provide the 95 percent confidence bound within which actual emissions from this source category are likely to fall for the year 2019, using the IPCC methodology. The results of the Approach 2 uncertainty analysis are summarized in Table 3-69. Natural gas systems CH_4 emissions in 2019 were estimated to be between 133.4 and 180.1 MMT CO_2 Eq. at a 95 percent confidence level. Natural gas systems CO_2 emissions in 2019 were estimated to be between 31.3 and 44.3 MMT CO_2 Eq. at a 95 percent confidence level.

Uncertainty bounds for other years of the time series have not been calculated, but uncertainty is expected to vary over the time series. For example, years where many emission sources are calculated with interpolated data would likely have higher uncertainty than years with predominantly year-specific data. In addition, the emission sources that contribute the most to CH_4 and CO_2 emissions are different over the time series, particularly when comparing recent years to early years in the time series. For example, venting emissions were higher and flaring emissions were lower in early years of the time series, compared to recent years. Technologies also changed over the time

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

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

series (e.g., liquids unloading with plunger lifts and reduced emissions completions were not used early in the time series and cast iron distribution mains were more prevalent than plastic mains in early years). Transmission and gas processing compressor leak and vent emissions were also higher in the early years of the time series.

Table 3-69: Approach 2 Quantitative Uncertainty Estimates for CH_4 and Non-combustion CO_2 Emissions from Natural Gas Systems (MMT CO_2 Eq. and Percent)

Source	Gas	2019 Emission Estimate (MMT CO_2 Eq.)[b]	Uncertainty Range Relative to Emission Estimate[a] (MMT CO_2 Eq.)		(%)	
			Lower Bound[b]	Upper Bound[b]	Lower Bound[b]	Upper Bound[b]
Natural Gas Systems	CH_4	157.6	133.4	180.1	-15%	+14%
Natural Gas Systems	CO_2	37.2	31.3	44.3	-16%	19%

[a] Range of emission estimates estimated by applying the 95 percent confidence intervals obtained from the Monte Carlo Simulation analysis conducted for the year 2019 CH_4 and year 2018 CO_2 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 3-63 and Table 3-64.

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

QA/QC and Verification Discussion

The natural gas systems emission estimates in the Inventory are continually being reviewed and assessed to determine whether emission factors and activity factors accurately reflect current industry practices. A QA/QC analysis was performed for data gathering and input, documentation, and calculation. QA/QC checks are consistently conducted to minimize human error in the model calculations. EPA performs a thorough review of information associated with new studies, GHGRP data, regulations, public webcasts, and the Natural Gas STAR Program to assess whether the assumptions in the Inventory are consistent with current industry practices. The EPA has a multi-step data verification process for GHGRP data, including automatic checks during data-entry, statistical analyses on completed reports, and staff review of the reported data. Based on the results of the verification process, the EPA follows up with facilities to resolve mistakes that may have occurred.[88]

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

In recent years, several studies have measured emissions at the source level and at the national or regional level and calculated emission estimates that may differ from the Inventory. There are a variety of potential uses of data from new studies, including replacing a previous estimate or factor, verifying or QA of an existing estimate or

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

factor, and identifying areas for updates. In general, there are two major types of studies related to oil and gas greenhouse gas data: studies that focus on measurement or quantification of emissions from specific activities, processes and equipment, and studies that use tools such as inverse modeling to estimate the level of overall emissions needed to account for measured atmospheric concentrations of greenhouse gases at various scales. The first type of study can lead to direct improvements to or verification of Inventory estimates. In the past few years, EPA has reviewed and in many cases, incorporated data from these data sources. The second type of study can provide general indications of potential over- and under-estimates.

One comment on the public review draft suggested that the inventory estimates be compared with an observational analysis from a 2019 Lan et al. study.[89] Lan et al. estimated an average increasing trend of U.S. oil and gas methane emissions of 3.4 percent +/-1.4 percent per year between 2006 and 2015, based on three U.S. measurement sites that were "substantially influenced by O&NG activities." This study did not address the magnitude of emissions. Nationally, in the Inventory, methane emissions from oil and gas decreased by an average of 1 percent per year from 2006 to 2015, largely driven by the natural gas distribution and transmission and storage segments. A key challenge in using these types of studies to assess Inventory results is having a relevant basis for comparison (e.g., the two data sets should have comparable time frames and geographic coverage, and the independent study should assess data from the Inventory and not another data set, such as the Emissions Database for Global Atmospheric Research, or "EDGAR"). In an effort to improve the ability to compare the national-level Inventory with measurement results that may be at other scales, a team at Harvard University along with EPA and other coauthors developed a gridded inventory of U.S. anthropogenic methane emissions with 0.1 degree x 0.1 degree spatial resolution, monthly temporal resolution, and detailed scale-dependent error characterization.[90] The gridded methane inventory is designed to be consistent with the U.S. EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2014* estimates for the year 2012, which presents national totals.[91] An updated version of the gridded inventory is being developed and will improve efforts to compare results of the Inventory with atmospheric studies.

Recalculations Discussion

EPA received information and data related to the emission estimates through GHGRP reporting, the annual Inventory formal public notice periods, stakeholder feedback on updates under consideration, and new studies. In September and November 2020, EPA released draft memoranda that discussed changes under consideration, and requested stakeholder feedback on those changes. EPA then created updated versions of the memoranda to document the methodology implemented in the current Inventory.[92] Memoranda cited in the Recalculations Discussion below are: *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2019: Update for Natural Gas Customer Meter Emissions* (*Customer Meters* memo) and *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2019: Update for Produced Water Emissions* (*Produced Water* memo).

EPA thoroughly evaluated relevant information available and made several updates to the Inventory, including using revised emission factors and produced water volumes to calculate produced water emissions, and using GTI 2019 along with GTI 2009 study data to calculate customer meter emissions. These changes are discussed in detail below. In addition, certain sources did not undergo methodological updates, but CH_4 and/or CO_2 emissions changed by greater than 0.05 MMT CO_2 Eq., comparing the previous estimate for 2018 to the current (recalculated) estimate for 2018. For sources without methodological updates, the emissions changes were mostly due to GHGRP data submission revisions and updates to well counts in the Enverus dataset.

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[89] See <https://agupubs.onlinelibrary.wiley.com/doi/epdf/10.1029/2018GL081731>.

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

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

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

The combined impact of revisions to 2018 natural gas sector CH_4 emissions, compared to the previous Inventory, is an increase from 140.0 to 152.5 MMT CO_2 Eq. (12.6 MMT CO_2 Eq., or 9 percent). The recalculations resulted in an average increase in CH_4 emission estimates across the 1990 through 2018 time series, compared to the previous Inventory, of 6.6 MMT CO_2 Eq., or 4 percent.

The combined impact of revisions to 2018 natural gas sector CO_2 emissions, compared to the previous Inventory, is a decrease from 35.0 MMT to 33.9 MMT, or 3 percent. The recalculations resulted in an average decrease in emission estimates across the 1990 through 2018 time series, compared to the previous Inventory, of 0.1 MMT CO_2 Eq., or 0.5 percent.

The combined impact of revisions to 2018 natural gas sector N_2O emissions, compared to the previous Inventory, is an increase from 10.4 kt CO_2 Eq. to 11.2 kt CO_2 Eq., or 8 percent. The recalculations resulted in an average increase in emission estimates across the 1990 through 2018 time series, compared to the previous Inventory, of 6 percent.

In Table 3-70 and Table 3-71 below are categories in Natural Gas Systems with recalculations resulting in a change of greater than 0.05 MMT CO_2 Eq., comparing the previous estimate for 2018 to the current (recalculated) estimate for 2018. No changes made to N_2O estimates resulted in a change greater than 0.05 MMT CO_2 Eq. For more information, please see the Recalculations Discussion below.

Table 3-70: Recalculations of CO_2 in Natural Gas Systems (MMT CO_2)

Segment 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
Production	***9.6***	**9.8**	**11.0**
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**	**37.2**

+ Does not exceed 0.05 MMT CO_2.

Table 3-71: Recalculations of CH_4 in Natural Gas Systems (MMT CO_2 Eq.)

Segment 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***	**90.8**	**93.7**
Produced Water (Onshore Production)	*1.5*	4.7	4.7
G&B Station Sources	*31.4*	35.0	37.3
Pneumatic Controllers (Onshore Production)	*25.4*	26.9	28.2
Liquids Unloading	*4.4*	5.1	4.4
HF Workovers	*0.6*	0.5	0.4
Chemical Injection Pumps	2.7	2.9	2.8
Kimray Pumps	1.8	1.9	1.8
Gas Engines	6.2	6.4	6.3
Compressors	1.6	1.7	1.7

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***	**152.5**	**157.6**

+ Does not exceed 0.05 MMT CO_2 Eq.

Exploration

HF Gas Well Completions (Recalculation with Updated Data)

HF gas well completions CH_4 emissions estimates averaged no change across the time series. However, emissions decreased by 18 percent in 2018, compared to the previous Inventory, with the largest change being in RECs with Venting. These changes were due to GHGRP submission revisions.

Table 3-72: HF Gas Well Completions National Emissions (Metric Tons CH_4)

Source	1990	2005	2015	2016	2017	2018	2019
HF Completions - Non-REC with Venting	156,988	382,619	924	1,109	2,932	1,085	641
HF Completions - Non-REC with Flaring	2,223	6,828	394	75	476	621	335
HF Completions - REC with Venting	0	6,489	14,463	12,569	37,650	28,934	17,827
HF Completions - REC with Flaring	0	1,855	8,760	4,581	5,656	1,344	1,139
Total Emissions	**159,211**	**397,791**	**24,541**	**18,334**	**46,713**	**31,984**	**19,942**
Previous Estimate	*153,924*	*397,427*	*24,566*	*18,177*	*47,414*	*39,036*	*NA*

NA (Not Applicable)

HF gas well completion CO_2 emissions estimates decreased by an average of approximately 1 percent across the time series and decreased by 26 percent in 2018, compared to the previous Inventory, primarily due to decreases in emissions from RECs with Flaring. These changes were due to GHGRP submission revisions.

Table 3-73: HF Gas Well Completions National Emissions (kt CO_2)

Source	1990	2005	2015	2016	2017	2018	2019
HF Completions - Non-REC with Venting	11	26	0.2	+	0.4	+	+
HF Completions - Non-REC with Flaring	402	1,236	49	12	37	54	32
HF Completions - REC with Venting	0	3	1	0	1	3	0
HF Completions - REC with Flaring	0	370	218	167	398	233	198
Total Emissions	**413**	**1,634**	**268**	**179**	**436**	**290**	**230**
Previous Estimate	*399*	*1,633*	*268*	*177*	*449*	*392*	*NA*

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

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

Non-HF gas well completion CH_4 emissions estimates decreased by an average of 3 percent across the time series and decreased by 82 percent in 2018, compared to the previous inventory. These changes were due to GHGRP submission revisions and a correction to the Inventory calculations of the number of non-HF completions that were vented versus flared in 2018.

Table 3-74: Non-HF Gas Well Completions National Emissions (Metric Tons CH_4)

Source	1990	2005	2015	2016	2017	2018	2019
Non-HF Completions - Vented	5,747	10,925	14,872	8,602	850	272	832
Non-HF Completions - Flared	20	38	40	82	714	481	0
Total Emissions	**5,767**	**10,963**	**14,912**	**8,684**	**1,564**	**753**	**832**
Previous Estimate	*5,717*	*10,252*	*13,667*	*8,077*	*1,440*	*4,285*	*NA*

NA (Not Applicable)

Production

Produced Water (Methodological Update)

EPA updated the calculation methodology for produced water to estimate emissions for all produced water from natural gas wells. Previous inventories only estimated emissions for two CBM formations (i.e., Powder River in Wyoming and Black Warrior in Alabama). The updated methodology includes updates to the produced water quantities and the emission factor, each of which are discussed here. EPA's considerations for this source are documented in the *Produced Water* Memo.[93]

Produced water quantities (i.e., bbl) from natural gas wells were obtained for 36 natural gas-producing states as described below:

- Produced water quantities for 1990-2018 were obtained using DrillingInfo and Prism datasets from Enverus for 29 states (i.e., AK, AL, AR, AZ, CA, CO, FL, ID, KY, LA, MD, MI, MN, MO, MS, MT, NC, ND, NE, NM, NV, NY, OR, SD, TN, TX, UT, VA, and WY) (Enverus 2021). Linear interpolation was used to correct an obviously inaccurate new-zero produced water quantity value in Colorado for 1998.
- For four additional states, produced water quantities for 1990-2018 were available on state agency websites– KS (Kansas Department of Health and Environment 2020), OH (Ohio Environmental Protection

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

Agency 2020), OK (Oklahoma Department of Environmental Quality 2020), and PA (Pennsylvania Department of Environmental Protection 2020). Produced water quantities for 2018 were used as proxy data for 2019 for these four states.

- Produced water quantities for 1990-2018 were estimated for three states (IL, IN, and WV) using state-level produced water production ratios for gas wells. Well-level produced water data for gas wells for 2011 were obtained from the DrillingInfo dataset (Enverus 2021) and gas production data were obtained from state agency websites – IL (Illinois Office of Oil and Gas Resource Management 2020), IN (Indiana Division of Oil & Gas 2020), and WV (West Virginia Department of Environmental Protection 2020). Using these well-level produced water data and the gas production data, production ratios were developed for gas wells in each state. These production ratios were then applied to annual state-level gas production data (2000-2019) from EIA (EIA 2020). Produced water quantities for 2018 were used as proxy data for 2019 for these three states.

EPA updated the produced water EF to use an EF consistent with the Production Module of the 2017 Oil and Gas Tool,[94] and applied this EF to all gas well produced water (EPA 2017). Overall, the update increases the emission estimate for produced water (now including all gas production), by approximately three times in recent years, compared to the previous Inventory.

EPA received feedback on this update through its September 2020 memo and through the public review draft of the inventory.

A stakeholder indicated that the typical practice is to route produced water to a tank battery, once it reaches the surface and has been separated from the oil and gas. A stakeholder requested that data from the latest 2017 Ground Water Protection Council produced water management practices survey be used to determine the percent of produced water that is stored in tanks. The stakeholder indicated that approximately 16 percent of produced water has the potential of being stored in a tank battery that could potentially flash (based on the 2012 Ground Water Protection Council produced water management practices survey). After further assessment of the 2012 and 2017 water management practice surveys, EPA maintained the assumption that all produced water goes through tanks and emissions are flashed, consistent with the approach used for the public review draft of the Inventory.

A stakeholder commented that current regulations under 40 CFR 60 subpart OOOOa require that certain storage vessels route emission vapors to a recovery device, flare, or other control device. EPA currently does not have specific data to address the use of controls on produced water tanks but will continue to assess this issue in future inventories should additional data become available.

Table 3-75: Produced Water National CH_4 Emissions (Metric Tons CH_4)

Source	1990		2005		2015	2016	2017	2018	2019
Gas Well Produced Water	82,250		139,453		171,523	154,394	157,488	188,601	187,070
Previous Estimate	*2,767*		*59,884*		*60,745*	*61,673*	*61,673*	*61,673*	*61,673*

NA (Not Applicable)

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

Methane emission estimates for sources at gathering and boosting stations increased in the current Inventory by an average of 2 percent across the time series and increased by 11 percent in 2018, compared to the previous Inventory. The G&B sources with the largest increase in CH_4 emissions estimates for year 2018 are tanks (increase of 70 kt, or 39 percent), gas engines (increase of 19 kt, or 5 percent), and station blowdowns (increase of 17 kt or 27 percent). These changes were due to GHGRP submission revisions.

[94] *Instructions for Using the 2017 EPA Nonpoint Oil and Gas Emissions Estimation Tool, Production Module*. Produced by Eastern Research Group, Inc. (ERG) for U.S. Environmental Protection Agency. October 2019.

Flare stack CO_2 emissions at G&B stations increased in the current inventory by an average of 0.6 percent, compared to the previous Inventory. These changes were due to GHGRP submission revisions.

Table 3-76: Gathering Stations Sources National CH_4 Emissions (Metric Tons CH_4)

Source	1990		2005		2015	2016	2017	2018	2019
Compressors	130,744		165,028		261,792	260,325	278,692	296,279	309,465
Tanks	131,152		165,543		262,610	261,139	255,244	251,243	301,338
Station Blowdowns	20,715		26,148		41,479	41,247	63,833	78,550	68,773
Dehydrator Vents - Large units	36,022		45,468		72,128	71,724	61,297	56,932	55,218
High-bleed Pneumatic Devices	17,466		22,046		34,973	34,777	33,985	24,599	23,624
Intermittent Bleed Pneumatic Devices	80,265		101,312		160,716	159,816	178,037	163,253	170,952
Low-Bleed Pneumatic Devices	2,784		3,515		5,575	5,544	5,877	5,803	6,819
Gas Engines	173,040		218,415		346,483	344,542	369,192	392,459	410,376
Other Gathering Sources	60,349		69,352		120,838	120,161	113,470	129,876	145,139
Total Emissions	**652,538**		**823,648**		**1,306,595**	**1,299,276**	**1,359,628**	**1,398,994**	**1,491,704**
Previous Estimate	*641,624*		*815,454*		*1,293,262*	*1,281,711*	*1,281,484*	*1,257,799*	*NA*

NA (Not Applicable)

Table 3-77: Gathering Stations Flare Stacks National CO_2 Emissions (Metric Tons CO_2)

Source	1990		2005		2015	2016	2017	2018	2019
Flare Stacks	1,367,178		1,725,682		2,737,537	2,722,202	2,317,495	4,386,761	5,005,631
Previous Estimate	*1,354,751*		*1,721,783*		*2,730,646*	*2,706,255*	*2,300,171*	*4,205,760*	*NA*

NA (Not Applicable)

Pneumatic Controllers (Recalculation with Updated Data)

Pneumatic controller CH_4 emission estimates increased in the current Inventory by an average of 3.9 percent across the time series, compared to the previous Inventory. This change was due to GHGRP submission revisions which increased the number of intermittent bleed controllers and updates to well counts in the Enverus dataset.

Table 3-78: Production Segment Pneumatic Controller National Emissions (Metric Tons CH_4)

Source	1990		2005		2015	2016	2017	2018	2019
Low Bleed	0		24,049		33,107	32,610	35,856	35,671	33,538
High Bleed	291,948		481,227		106,286	107,714	112,764	92,886	74,565
Intermittent Bleed	190,386		557,410		979,719	923,468	954,461	947,089	1,018,428
Total Emissions	**482,334**		**1,062,685**		**1,119,112**	**1,063,791**	**1,103,082**	**1,075,645**	**1,126,531**
Previous Estimate	*490,594*		*1,023,770*		*1,072,732*	*1,037,136*	*1,062,086*	*1,016,357*	*NA*

NA (Not Applicable)

Liquids Unloading (Recalculation with Updated Data)

Liquids unloading CH_4 emission estimates increased for 2018 by 15 percent in the current Inventory, compared to the previous Inventory. Compared to the previous Inventory, on average across the time series, liquids unloading

CH_4 emission estimates increased more than 2 percent. These changes were due to GHGRP submission revisions and updates to well counts in the Enverus dataset.

Table 3-79: Liquids Unloading National Emissions (Metric Tons CH_4)

Source	1990		2005		2015	2016	2017	2018	2019
Unloading with Plunger Lifts	NO		127,621		65,375	61,359	60,724	83,841	76,937
Unloading without Plunger Lifts	355,840		250,973		102,166	84,096	90,767	120,146	98,892
Total Emissions	**355,840**		**378,594**		**167,540**	**145,455**	**151,492**	**203,987**	**175,828**
Previous Estimated Emissions	*371,391*		*372,614*		*160,061*	*127,663*	*129,790*	*177,298*	*NA*

NO (Not Occurring)
NA (Not Applicable)

HF Gas Well Workovers (Recalculation with Updated Data)

HF gas well workover CH_4 emissions decreased an average of 1 percent across the time series and decreased by 16 percent in 2018, when comparing the current Inventory to the previous Inventory, mostly due to decreases in emissions from RECs with Venting. These changes were due to GHGRP submission revisions.

Table 3-80: HF Gas Well Workovers National Emissions (Metric Tons CH_4)

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**
Previous Estimate	*26,139*		*62,437*		*12,175*	*15,155*	*31,485*	*24,422*	*NA*

NO (Not Occurring)
NA (Not Applicable)

Gas Engines (Recalculation with Updated Data)

Gas engine (combustion slip) CH_4 emissions increased an average of 5 percent across the time series, compared to the previous Inventory. These changes were due to updates to well counts in the Enverus dataset.

Table 3-81: Gas Engine National Emissions (Metric Tons CH_4)

Source	1990		2005		2015	2016	2017	2018	2019
Gas Engines	116,684		129,715		132,093	124,835	120,272	116,437	111,886
Previous Estimate	*116,558*		*123,713*		*125,843*	*119,100*	*114,599*	*110,432*	*NA*

NA (Not Applicable)

Chemical Injection Pumps (Recalculation with Updated Data)

Chemical injection pump CH_4 emissions estimates increased an average of 4 percent across the time series, compared to the previous Inventory. These changes were due to updates to well counts in the Enverus dataset.

Table 3-82: Chemical Injection Pump National Emissions (Metric Tons CH_4)

Source	1990		2005		2015	2016	2017	2018	2019

Chemical Injection Pumps	26,060		87,007		117,857	116,038	115,322	114,636	112,843
Previous Estimate	*26,323*		*83,687*		*113,336*	*113,243*	*111,421*	*109,376*	*NA*

NA (Not Applicable)

Kimray Pumps (Recalculation with Updated Data)

CH_4 emissions from Kimray pumps decreased by an average of 2 percent across time series, compared to the previous Inventory. These changes were due to updates to well counts in the Enverus dataset.

Table 3-83: Kimray Pumps National Emissions (Metric Tons CH_4)

Source	1990		2005		2015	2016	2017	2018	2019
Kimray Pumps	141,304		110,923		76,818	75,485	75,042	74,596	73,426
Previous Estimate	*148,064*		*114,936*		*73,850*	*73,660*	*72,475*	*71,125*	*NA*

NA (Not Applicable)

Compressors (Recalculation with Updated Data)

Compressors CH_4 emissions estimates increased an average of 1 percent across the time series, compared to the previous Inventory. These changes were due to updates to well counts in the Enverus dataset.

Table 3-84: Compressors National Emissions (Metric Tons CH_4)

Source	1990		2005		2015	2016	2017	2018	2019
Compressors	28,189		56,528		70,121	68,904	68,500	68,093	67,025
Previous Estimate	*28,645*		*55,520*		*67,412*	*67,239*	*66,157*	*64,925*	*NA*

NA (Not Applicable)

Well Counts (Recalculation with Updated Data)

EPA uses annual producing gas well counts as an input for estimates of emissions from multiple sources in the Inventory, including exploration well testing, pneumatic controllers, chemical injection pumps, well workovers, and equipment leaks. Annual well count data are obtained from Enverus for the entire time series during each Inventory cycle, and a new data processing methodology was implemented this year due to a restructuring of the Enverus well count data (Enverus 2021). Due to the data restructuring and the new processing methodology, annual gas well counts increased by an average of 1 percent across the 1990-2018 time series and increased by 5 percent in 2018, compared to the previous Inventory.

Table 3-85: National Gas Well Counts

Source	1990		2005		2015	2016	2017	2018	2019
Gas Wells	185,141		351,982		436,432	429,697	427,046	424,507	417,866
Previous Estimate	*193,232*		*346,484*		*419,692*	*419,346*	*412,601*	*405,026*	*NA*

NA (Not Applicable)

In December 2020, EIA released an updated time series of national oil and gas well counts (covering 2000 through 2018). EIA estimates 969,136 total producing wells for year 2019. EPA's total well count for this year is 939,637. EPA's well counts are generally lower than EIA's (e.g., around 3 percent lower in 2019). EIA's well counts include side tracks (i.e., secondary wellbore away from original wellbore in order to bypass unusable formation, explore nearby formations, or other reasons) completions, and recompletions, and therefore are expected to be higher than EPA's which include only producing wells. EPA and EIA use a different threshold for distinguishing between oil versus gas (EIA uses 6 mcf/bbl, while EPA uses 100 mcf/bbl), which results in EIA having a lower fraction of oil wells (e.g., 44 percent versus EPA's 56 percent in 2019) and a higher fraction of gas wells (e.g., 56 percent versus EPA's 44 percent in 2019) than EPA.

Processing

Acid Gas Removal (Recalculation with Updated Data)

Acid gas removal unit (AGR) CO_2 emission estimates decreased by less than 1 percent across the time series, compared to the previous Inventory. The 2018 estimate decreased by 4 percent when compared to the previous inventory. These changes are due to GHGRP submission revisions.

Table 3-86: AGR National CO_2 Emissions (kt CO_2)

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
Previous Estimate	*28,282*	*15,339*	*14,979*	*16,679*	*17,182*	*17,451*	*NA*

NA (Not Applicable)

Flares (Recalculation with Updated Data)

Processing segment flare CO_2 emission estimates decreased by less than 1 percent across the 1993 to 2018 time series in the current Inventory. Processing segment flare CO_2 emission estimates decreased by approximately 8 percent for 2018 in the current Inventory, compared to the previous Inventory. These changes are due to GHGRP submission revisions.

Table 3-87: Processing Segment Flares National Emissions (kt CO_2)

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

NO (Not Occurring)
NA (Not Applicable)

Reciprocating Compressors (Recalculation with Updated Data)

Reciprocating compressor CH_4 emission estimates decreased by less than 1 percent on average for 2011 to 2018 in the current Inventory and decreased by 5 percent for 2018 in the current Inventory, compared to the previous Inventory. This decrease in the CH_4 emission estimates is due to GHGRP submission revisions.

Table 3-88: Processing Segment Reciprocating Compressors National Emissions (Metric Tons CH_4)

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

NA (Not Applicable)

Transmission and Storage

There were no methodological updates to the transmission and storage segment, but there were recalculations due to updated data that resulted in an average increase in calculated emissions over the time series from this segment of 0.19 MMT CO_2 Eq. of CH_4 (or 0.5 percent) and less than 0.01 MMT CO_2 (or 2 percent).

Transmission Station Reciprocating Compressors (Recalculation with Updated Data)

Methane emission estimates from reciprocating compressors at transmission compressor stations increased by an average of 0.2 percent for 2011 to 2018, compared to the previous Inventory. This increase in the CH_4 emission estimates is due to GHGRP submission revisions.

Table 3-89: Transmission Station Reciprocating Compressors National Emissions (Metric Tons CH_4)

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

NO (Not Occurring)
NA (Not Applicable)

Storage Pneumatic Controllers (Recalculation with Updated Data)

Storage segment pneumatic controller CH_4 emission estimates increased in the current Inventory for 2014-2018, compared to the previous Inventory. Emission estimates for 2018 increased by 24,169 metric tons CH_4, compared to the previous Inventory. This increase in the CH_4 emission estimates is due to GHGRP submission revisions.

Table 3-90: Storage Segment Pneumatic Controller National Emissions (Metric Tons CH_4)

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**
Previous Estimate	*44,441*		*35,263*		*22,094*	*1,402*	*27,364*	*141*	*NA*

NE (Not Estimated)
NA (Not Applicable)

LNG Export Terminals (Recalculation with Updated Data)

LNG export terminal CO_2 emissions estimates for equipment leaks, compressors, and flares increased by 20 percent in 2018, compared to the previous Inventory. This increase in the CO_2 emission estimate for 2018 is due to GHGRP submission revisions.

Table 3-91: LNG Export Terminal National Emissions (Metric Tons CO_2)

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
Previous Estimate	*23*		*23*		*23*	*97,935*	*277,979*	*273,956*	*NA*

NA (Not Applicable)

Distribution

Customer Meters (Methodological Update)

EPA updated the commercial and industrial meters methodologies to use leak data from the GTI 2009 and GTI 2019 studies. The GTI 2019 study measured CH_4 emissions rates at commercial and industrial meters in six regions across the country and calculated population EFs for each meter type. The GTI 2009 study conducted similar measurements and was used to calculate emissions for commercial and industrial meters in the previous (1990 to 2018) Inventory. EPA applied weighted average population EFs from the two studies across the time series for the methodology implemented in the Inventory. The *Customer Meters memo* provides details on the methodology implemented into the final inventory.

Commercial and industrial meter CH_4 and CO_2 emissions increased by an average of 173 percent across the time series, compared to the previous Inventory. The increase in both CH_4 and CO_2 emissions is due to differences in the EFs used in the current Inventory and the previous Inventory. The previous inventory used a lower EF (based on commercial meter measurements only) and applied that EF to both commercial and industrial meter counts. The updated methodology uses commercial meter data from both the 2009 and 2019 GTI studies to develop an EF that is applied to commercial meter counts, and uses industrial meter data from both the 2009 (leak emissions only) and GTI 2019 studies to develop an EF that is applied to industrial meter counts. No change was made to the activity data approach.

EPA received comments on the September 2020 version of the *Customer Meters* Memo and through the public review draft of the Inventory. These comments included a recommendation to delay updates until additional data could be collected. The comments also recommended using separate EFs for commercial and industrial meters and region-specific EFs. The largest source of emissions from customer meters in the 2009 study was vented emissions from industrial meters, with an average emission factor per meter of 3,487 kg/year, compared with an average emission factor per industrial meter from leaks of 105 kg/year. Venting emissions were observed and measured at 2 out of the 6 companies participating in the 2009 GTI study. This source of emissions was not studied in the 2019 GTI study. The final methodology for industrial meters uses an EF calculated only from leak emissions, which have less variability, and does not include the more limited and highly variable vented emissions. EPA did not use region-specific EFs due to the limited data available for each region, but did finalize separate EFs for commercial and industrial meters that rely on the leak emissions from the 2009 and 2019 GTI studies. Using data from both studies to calculate population EFs greatly increases the number of data points that serve as the basis of the EFs, instead of only using the commercial meter EF from the 2009 GTI study. EPA seeks stakeholder feedback on upcoming or ongoing research studies that measure vented emissions from industrial meters.

Table 3-92: Commercial and Industrial Meter National Emissions (Metric Tons CH_4)

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**
Previous Estimate	*43,362*		*52,605*		*54,919*	*55,129*	*55,324*	*56,140*	*NA*

NA (Not Applicable)

Table 3-93: Commercial and Industrial Meter National Emissions (Metric Tons CO_2)

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**
Previous Estimate	*1,277*		*1,549*		*1,617*	*1,623*	*1,629*	*1,653*	*NA*

NA (Not Applicable)

Planned Improvements

EPA seeks stakeholder feedback on the improvements noted below.

Post-Meter Fugitive Emissions

The Inventory does not currently include estimates for post-meter fugitive (leakage) emissions. The 2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2019) include methods and default emission factors to estimate these emissions. In IPCC 2019, post-meter fugitives includes leak emissions from appliances in commercial and residential sectors (leakage from house piping and appliances, including home heating, water heating, stoves, and barbecues), leakage at industrial plants and power stations (leakage beyond gas meters including internal piping), and leakage from natural gas-fueled vehicles (vehicles with fuels produced from natural gas e.g., LNG, CNG, RNG).

For consistency with IPCC 2019, and to improve completeness of the Inventory estimates, EPA is considering updating next year's Inventory to include this emission source. EPA will seek stakeholder feedback on emission factors and activity data for this source.

Anomalous Emissions Events (Well Blowouts)

In recent years, a number of studies have assessed and, in some cases, quantified total emissions for gas well blowout events.[95,96] EPA is considering updating next year's inventory to include these events. EPA will seek stakeholder feedback on estimates for this source.

Transmission and Storage

Storage Wells

As part of the stakeholder process for the current (1990 to 2019) Inventory, EPA developed draft CH_4 emission estimates for underground storage well leak emissions in the transmission and storage segment. EPA's considerations for this source are documented in the EPA memorandum *Inventory of U. S. Greenhouse Gas Emissions and Sinks 1990-2019: Updates Under Consideration to Natural Gas Underground Storage Well Emissions* (*Underground Storage Wells* memo).[97] EPA presented multiple options to calculate storage well emissions in the *Underground Storage Wells* memo, and in the public review draft of the Inventory, presented estimated emissions using a 'per station' EF along with underground storage station counts. EPA received comment suggesting a recent PHMSA data set for national storage well counts.[98] EPA is considering the use of the national storage well data set and the GSI emission factors in next year's Inventory.

Table 3-94: Draft Underground Storage Wells National Emissions (Metric Tons CH_4) and Well Counts – Not Included in Totals

Source	1990		2005		2015	2016	2017	2018	2019
Storage Wells CH_4 (EPA draft)[a]	7,838		7,431		7,566	7,508	7,489	7,431	7,566

[95] See <https://www.pnas.org/content/116/52/26376>.

[96] See <https://agupubs.onlinelibrary.wiley.com/doi/10.1029/2020GL090864>.

[97] 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>.

[98] See <https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids>.

Storage Wells CH_4 (PHMSA and GSI)[b]							7,523	7,483	7,426
Well Counts (PHMSA)							14,268	14,192	14,084
Current Estimate CH_4[c]	*13,565*		*14,910*		*14,250*	*13,428*	*13,632*	*15,439*	*15,495*
Current Estimate Well Counts	*16,853*		*18,524*		*17,703*	*16,682*	*16,936*	*19,181*	*19,250*

NA (Not Applicable)

[a] Estimate developed using a 'per station' weighted average EF (based on data from the GSI 2019 study, GHGRP wellhead component counts, and field type distributions from EIA) and the number of underground storage stations over the time series (already in the Inventory).

[b] Estimate developed using PHMSA storage well counts and GSI emission factors. EPA has not developed an approach for the full time series for the activity data or emission factors, and is showing preliminary estimates for 2017 through 2019 emissions because those are the years where PHMSA storage well counts are available.

[c] The Current 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.

Transmission Station Counts

Stakeholder feedback suggested alternate approaches for calculating the annual number of transmission stations. EPA will consider the update for next year's Inventory.

Mud Degassing

As part of the stakeholder process for the current (1990 to 2019) Inventory, EPA developed new CH_4 emission estimates for onshore mud degassing in the exploration segment. To date, the Inventory has not included emissions from onshore exploration mud degassing. EPA's considerations for this source are documented in the EPA memorandum *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2019: Update Under Consideration for Mud Degassing Emissions (Mud Degassing* memo). EPA estimated preliminary emissions using CH_4 emission factors from EPA (EPA 1977) and well counts data from Enverus DrillingInfo data. In estimating national preliminary CH_4 estimates for mud degassing, EPA incorporated an estimate of 26 days as an average drilling duration and 61.2 percent (by weight) as the default CH_4 content of natural gas. EPA developed preliminary national estimates for 2 different scenarios: 1) EPA assumed 80 percent of drilling operations were performed using water-based muds and the remaining 20 percent used oil-based muds; and 2) EPA assumed 100 percent of drilling operations were performed using water-based muds. Methane emissions from mud degassing averaged 73 kt over the time series for scenario 1 and 86 kt for scenario 2 (100 percent water-based muds), or around 2 MMT CO_2 Eq. This update would increase emissions from the exploration segment but would have a small impact on overall CH_4 emissions from natural gas systems.

EPA notes that estimates for mud degassing using similar assumptions are included in several other bottom-up inventories for greenhouse gases and other gases, including New York state, and the NEI.

EPA received feedback on this update through its September 2020 memo and through the public review draft of the Inventory. A stakeholder indicated the 12 inch diameter borehole and 25 percent formation porosity assumptions used in developing the CH_4 emission factor for water-based muds are outdated and recommended that an 8 inch borehole diameter and 10 percent porosity should be considered in developing the CH_4 EF. A stakeholder commented that current onshore practices are to drill with balanced or slightly over-balanced mud systems that keep gas from being entrained in the drilling mud and that mud degassing systems are rarely needed or used. A stakeholder also indicated that mainly oil-based muds are used for horizontal/lateral drilling and water-based muds are more frequently used for vertical drilling.

Additionally, EPA also received comments on the average drilling duration used in developing the draft estimates for onshore mud degassing. A stakeholder comment stated that EPA should only consider the duration the drill spends in the producing formation. Another comment indicated that EPA's average drilling duration assumption of 26 days per well is high and presented 2 examples–a Marcellus well takes 10 days to drill with 2-3 days in the producing formation; and the drilling duration in the Fayetteville shale dropped from 20 days in 2007 to 11 days in 2009. EPA's average drilling duration assumption of 26 days per well is comparable to average drilling duration developed from other inventories (New York – 24 days/well and CenSARA – 22 days/well). Refer to the *Mud Degassing* memo for further details.

EPA continues to seek feedback on average total drilling days and drilling days in the producing formation, CH_4 content of the gas, and the effect of balanced and over-balanced mud degassing systems. EPA will further assess the average drilling duration using updated Enverus data. Additionally, EPA is considering developing CO_2 estimates for onshore production mud degassing using the CH_4 estimates and a ratio of CO_2-to-CH_4.

Table 3-95: Draft Mud Degassing National CH_4 Emissions – Not Included in Totals (Metric Tons CH_4)

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
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

Upcoming Data, and Additional Data that Could Inform the Inventory

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

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

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

- Tank and flaring malfunction and control efficiency data.
- Improved equipment leak data
- Activity data and emissions data for production facilities that do not report to GHGRP.

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

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

The term "abandoned wells" encompasses various types of wells, including orphaned wells and other non-producing wells:

- Wells with no recent production, and not plugged. Common terms (such as those used in state databases) might include: inactive, temporarily abandoned, shut-in, dormant, and idle.

- Wells with no recent production and no responsible operator. Common terms might include: orphaned, deserted, long-term idle, and abandoned.
- Wells that have been plugged to prevent migration of gas or fluids.

The U.S. population of abandoned wells (including orphaned wells and other non-producing wells) is around 3.4 million (with around 2.7 million abandoned oil wells and 0.6 million abandoned gas wells). The methods to calculate emissions from abandoned wells involve calculating the total populations of plugged and unplugged abandoned oil and gas wells in the U.S. An estimate of the number of orphaned wells within this population is not developed as part of the methodology. Wells that are plugged have much lower average emissions than wells that are unplugged (less than 1 kg CH_4 per well per year, versus over 100 kg CH_4 per well per year). Around 40 percent of the abandoned well population in the United States is plugged. This fraction has increased over the time series (from around 19 percent in 1990) as more wells fall under regulations and programs requiring or promoting plugging of abandoned wells.

Abandoned oil wells. Abandoned oil wells emitted 209 kt CH_4 and 4 kt CO_2 in 2019. Emissions of both gases decreased by 10 percent from 1990, while the total population of abandoned oil wells increased 28 percent.

Abandoned gas wells. Abandoned gas wells emitted 55 kt CH_4 and 2 kt CO_2 in 2019. Emissions of both gases increased by 38 percent from 1990, as the total population of abandoned gas wells increased 84 percent.

Table 3-96: CH_4 Emissions from Abandoned Oil and Gas Wells (MMT CO_2 Eq.)

Activity	**1990**		**2005**		**2015**	**2016**	**2017**	**2018**	**2019**
Abandoned Oil Wells	5.8		6.0		5.9	5.9	5.7	5.8	5.2
Abandoned Gas Wells	1.0		1.2		1.5	1.5	1.5	1.5	1.4
Total	**6.8**		**7.2**		**7.4**	**7.4**	**7.2**	**7.3**	**6.6**

Note: Totals may not sum due to independent rounding.

Table 3-97: CH_4 Emissions from Abandoned Oil and Gas Wells (kt)

Activity	**1990**		**2005**		**2015**	**2016**	**2017**	**2018**	**2019**
Abandoned Oil Wells	231		238		235	236	229	231	209
Abandoned Gas Wells	40		49		59	60	58	59	55
Total	**271**		**287**		**294**	**296**	**288**	**290**	**263**

Note: Totals may not sum due to independent rounding.

Table 3-98: CO_2 Emissions from Abandoned Oil and Gas Wells (MMT CO_2)

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

+ Does not exceed 0.05 MMT CO_2.

Table 3-99: CO_2 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	4
Abandoned Gas Wells	2		2		3	3	3	3	2
Total	**6**		**7**		**7**	**7**	**7**	**7**	**7**

Note: Totals may not sum due to independent rounding.

Methodology

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

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

The total population of abandoned wells over the time series was estimated using historical data and Enverus data. The total abandoned well population was then split into plugged and unplugged wells by assuming that all abandoned wells were unplugged in 1950, using year-specific Enverus data to calculate the fraction of plugged abandoned wells (31 percent in 2016, 34 percent in 2017 and 2018, and 41 percent in 2019), and applying linear interpolation between the 1950 value and 2016 value to calculate the plugged fraction for intermediate years. See the memorandum *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2016: Abandoned Wells in Natural Gas and Petroleum Systems (2018 Abandoned Wells Memo)* for details.[99] Due to changes in the structure of the Enverus data, the fraction of abandoned wells that are plugged was calculated uniquely for 2019. See Planned Improvements section below for more information.

Abandoned Oil Wells

Table 3-100: Abandoned Oil Wells Activity Data, CH_4 and CO_2 Emissions (kt)

Source	1990		2005		2015	2016	2017	2018	2019
Plugged abandoned oil wells	394,907		624,930		789,418	809,774	890,458	905,866	1,109,167
Unplugged abandoned oil wells	1,720,692		1,809,892		1,813,090	1,819,396	1,765,889	1,777,547	1,604,291
Total Abandoned Oil Wells	2,115,599		2,434,821		2,602,508	2,629,170	2,656,346	2,683,413	2,713,458
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)	0		0		1	1	1	1	1

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

CH_4 from unplugged abandoned oil wells (MT)	231		238		235	236	229	230	208
Total CH_4 from Abandoned oil wells (MT)	**231**		**238**		**235**	**236**	**229**	**231**	**209**
Total CO_2 from Abandoned oil wells (MT)	**5**		**5**		**5**	**5**	**5**	**5**	**4**

Abandoned Gas Wells

Table 3-101: Abandoned Gas Wells Activity Data, CH_4 and CO_2 Emissions (kt)

Source	1990		2005		2015	2016	2017	2018	2019
Plugged abandoned gas wells	65,559		119,655		179,428	186,116	206,735	212,338	264,277
Unplugged abandoned gas wells	285,654		346,540		412,101	418,164	409,982	416,663	382,248
Total Abandoned Gas Wells	351,213		466,196		591,529	604,280	616,717	629,001	646,525
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 (kt)	0		0		0	0	0	0	0
CH_4 from unplugged abandoned gas wells (kt)	39		49		59	59	58	59	54
Total CH_4 from abandoned gas wells (kt)	**40**		**49**		**59**	**60**	**58**	**59**	**55**
Total CO_2 from abandoned gas wells (kt)	**2**		**2**		**3**	**3**	**3**	**3**	**2**

Uncertainty and Time-Series Consistency

To characterize uncertainty surrounding estimates of abandoned well emissions, EPA conducted a quantitative uncertainty analysis using the IPCC Approach 2 methodology (Monte Carlo simulation technique). See the *2018 Abandoned Wells Memo* for details of the uncertainty analysis methods. EPA used Microsoft Excel's @RISK add-in tool to estimate the 95 percent confidence bound around total methane emissions from abandoned oil and gas wells in year 2019, then applied the calculated bounds to both CH_4 and CO_2 emissions estimates for each population. The @RISK add-in provides for the specification of probability density functions (PDFs) for key variables within a computational structure that mirrors the calculation of the inventory estimate. EPA used measurement data from the Kang et al. (2016) and Townsend-Small et al. (2016) studies to characterize the CH_4 emission factor PDFs. For activity data inputs (e.g., total count of abandoned wells, split between plugged and unplugged), EPA assigned default uncertainty bounds of ± 10 percent based on expert judgment.

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

The results presented below in Table 3-102 provide the 95 percent confidence bound within which actual emissions from abandoned oil and gas wells are likely to fall for the year 2019, using the recommended IPCC methodology. Abandoned oil well CH_4 emissions in 2019 were estimated to be between 0.9 and 16.5 MMT CO_2 Eq., while abandoned gas well CH_4 emissions were estimated to be between 0.2 and 4.3 MMT CO_2 Eq. at a 95 percent confidence level. Uncertainty bounds for other years of the time series have not been calculated, but uncertainty is expected to vary over the time series.

Table 3-102: Approach 2 Quantitative Uncertainty Estimates for CH_4 and CO_2 Emissions from Petroleum and Natural Gas Systems (MMT CO_2 Eq. and Percent)

Source	Gas	2019 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	5.2	0.9	16.5	-83%	+217%
Abandoned Gas Wells	CH_4	1.4	0.2	4.3	-83%	+217%
Abandoned Oil Wells	CO_2	0.004	0.001	0.013	-83%	+217%
Abandoned Gas Wells	CO_2	0.002	0.0004	0.008	-83%	+217%

[a] Range of emission estimates estimated by applying the 95 percent confidence intervals obtained from the Monte Carlo Simulation analysis conducted for total abandoned oil and gas well CH_4 emissions in year 2019.

[b] All reported values are rounded after calculation. As a result, lower and upper bounds may not be duplicable from other rounded values as shown in table.

To calculate a time series of emissions for abandoned wells, EPA developed annual activity data for 1990 through 2019 by summing an estimate of total abandoned wells not included in recent databases, to an annual estimate of abandoned wells in the Enverus data set. As discussed above, the abandoned well population was split into plugged and unplugged wells by assuming that all abandoned wells were unplugged in 1950, using year-specific Enverus data to calculate the fraction of abandoned wells plugged in 2016 through 2019, and applying linear interpolation between the 1950 value and 2016 value to calculate plugged fraction for intermediate years. The same emission factors were applied to the corresponding categories for each year of the time series.

QA/QC and Verification Discussion

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

Recalculations Discussion

The counts of national abandoned wells were recalculated across the time series to use the latest Enverus data, which resulted in changes to the total abandoned well population and the allocation between petroleum and natural gas systems. The changes resulted from changes to the year-specific data for 1990 to 2019 available in the restructured Enverus data, which led EPA to recalculate the 1975 estimate of historical wells not included in the Enverus data set (which increased from 1,075,849 to 1,152,211 historical wells not completely included in Enverus).

Compared with the previous Inventory, counts of abandoned oil and gas wells are on average 1 percent and 12 percent, respectively, higher over 1990 to 2018. Total methane emissions from abandoned wells are around 3 percent higher across the time series than the previous Inventory and CO_2 emissions are around 4 percent higher.

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.

As noted above in the Methodology section, Enverus, a key data source for the calculation of the number of abandoned wells in the U.S., has restructured its information on the U.S. well population. EPA will seek stakeholder feedback on how to consider the restructured Enverus dataset for future inventories.

In addition to the wells identified as abandoned through analysis of the Enverus population and included in the Inventory estimates, for 2019, EPA identified approximately 900,000 wells in the Enverus dataset with only limited data available for use in determining whether the wells should be included in the abandoned well population. These wells may be included in some fraction of the estimate of historical wells estimated outside of the Enverus data set, but the extent is unknown at this time. To develop the national count of abandoned wells in the inventory for 2019, EPA did not include these approximately 900,000 wells along with the other abandoned wells from the Enverus data set, due to the limited data, and still relied on the historical estimate to account for old abandoned wells. Note, including these approximately 900,000 wells would have limited overall impact on the total count of abandoned wells (including them would simply reduce the historical estimate for the number of estimated abandoned wells missing from the Enverus data), but would impact the fraction of plugged and unplugged abandoned wells, as discussed next.

Using the restructured Enverus dataset, for the year 2019, the well status for approximately 400,000 wells in Texas changed from ‘inactive’ to ‘P&A’ (P&A = plugged and abandoned). Applying the same approach to calculating the fraction of plugged wells as in prior Inventories would have resulted in a large change in plugging status from year 2018 (34 percent plugged) to year 2019 (62 percent plugged). For this year’s Inventory, due to lack of clarity on the 900,000 wells noted in the paragraph above and on the 400,000 wells with changed plugging status, EPA calculated that 41 percent of abandoned wells are plugged for year 2019 by incorporating an assumption that all historical wells (those outside of the abandoned wells counts developed with Enverus) were not plugged. In other years of the time series, EPA relies only on the plugging status data available in Enverus and applies the calculated fraction to all abandoned wells.

EPA will seek stakeholder feedback on other approaches to estimate the total national abandoned well counts and the plugged abandoned well population, including feedback on how the approximately 900,000 wells with limited data should be considered.

3.9 Energy Sources of Precursor Greenhouse Gas Emissions

In addition to the main greenhouse gases addressed above, energy-related activities are also sources of precursor gases. The reporting requirements of the UNFCCC[100] request that information be provided on precursor greenhouse gases, which include carbon monoxide (CO), nitrogen oxides (NO_x), non-CH_4 volatile organic compounds (NMVOCs), and sulfur dioxide (SO_2). These gases are not direct greenhouse gases, but indirectly affect terrestrial radiation absorption by influencing the formation and destruction of tropospheric and stratospheric ozone, or, in the case of SO_2, by affecting the absorptive characteristics of the atmosphere. Additionally, some of these gases may react with other chemical compounds in the atmosphere to form compounds that are greenhouse

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

gases. Total emissions of NO_x, CO, and NMVOCs from energy-related activities from 1990 to 2019 are reported in Table 3-103. Sulfur dioxide emissions are presented in Section 2.3 of the Trends chapter and Annex 6.3.

Table 3-103: 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
International Bunker Fuels[a]	1,956	1,704	1,363	1,470	1,481	1,462	1,296
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
International Bunker Fuels[a]	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
International Bunker Fuels[a]	57	54	47	50	51	51	46

Note: Totals may not sum due to independent rounding.

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

Methodology

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

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

Uncertainty and Time-Series Consistency

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

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

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

Emissions resulting from the combustion of fuels used for international transport activities, termed international bunker fuels under the UNFCCC, are not included in national emission totals, but are reported separately based upon location of fuel sales. The decision to report emissions from international bunker fuels separately, instead of allocating them to a particular country, was made by the Intergovernmental Negotiating Committee in establishing the Framework Convention on Climate Change.[101] These decisions are reflected in the IPCC methodological guidance, including IPCC (2006), in which countries are requested to report emissions from ships or aircraft that depart from their ports with fuel purchased within national boundaries and are engaged in international transport separately from national totals (IPCC 2006).[102]

Two transport modes are addressed under the IPCC definition of international bunker fuels: aviation and marine.[103] Greenhouse gases emitted from the combustion of international bunker fuels, like other fossil fuels, include CO_2, CH_4 and N_2O for marine transport modes, and CO_2 and N_2O for aviation transport modes. Emissions from ground transport activities—by road vehicles and trains—even when crossing international borders are allocated to the country where the fuel was loaded into the vehicle and, therefore, are not counted as bunker fuel emissions.

The *2006 IPCC Guidelines* distinguish between three different modes of air traffic: civil aviation, military aviation, and general aviation. Civil aviation comprises aircraft used for the commercial transport of passengers and freight, military aviation comprises aircraft under the control of national armed forces, and general aviation applies to recreational and small corporate aircraft. The *2006 IPCC Guidelines* further define international bunker fuel use from civil aviation as the fuel combusted for civil (e.g., commercial) aviation purposes by aircraft arriving or departing on international flight segments. However, as mentioned above, and in keeping with the *2006 IPCC Guidelines*, only the fuel purchased in the United States and used by aircraft taking-off (i.e., departing) from the United States are reported here. The standard fuel used for civil and military aviation is kerosene-type jet fuel, while the typical fuel used for general aviation is aviation gasoline.[104]

Emissions of CO_2 from aircraft are essentially a function of fuel consumption. Nitrous oxide emissions also depend upon engine characteristics, flight conditions, and flight phase (i.e., take-off, climb, cruise, decent, and landing). Recent data suggest that little or no CH_4 is emitted by modern engines (Anderson et al. 2011), and as a result, CH_4 emissions from this category are reported as zero. In jet engines, N_2O is primarily produced by the oxidation of atmospheric nitrogen, and the majority of emissions occur during the cruise phase.

International marine bunkers comprise emissions from fuels burned by ocean-going ships of all flags that are engaged in international transport. Ocean-going ships are generally classified as cargo and passenger carrying, military (i.e., U.S. Navy), fishing, and miscellaneous support ships (e.g., tugboats). For the purpose of estimating greenhouse gas emissions, international bunker fuels are solely related to cargo and passenger carrying vessels, which is the largest of the four categories, and military vessels. Two main types of fuels are used on sea-going

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[101] 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).

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

[103] 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).

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

vessels: distillate diesel fuel and residual fuel oil. Carbon dioxide is the primary greenhouse gas emitted from marine shipping.

Overall, aggregate greenhouse gas emissions in 2019 from the combustion of international bunker fuels from both aviation and marine activities were 117.2 MMT CO_2 Eq., or 12.1 percent above emissions in 1990 (see Table 3-104 and Table 3-105). Emissions from international flights and international shipping voyages departing from the United States have increased by 112.2 percent and decreased by 46.0 percent, respectively, since 1990. The majority of these emissions were in the form of CO_2; however, small amounts of CH_4 (from marine transport modes) and N_2O were also emitted.

Table 3-104: CO_2, CH_4, and N_2O Emissions from International Bunker Fuels (MMT CO_2 Eq.)

Gas/Mode	1990		2005		2015	2016	2017	2018	2019
CO_2	**103.5**		**113.2**		**110.9**	**116.6**	**120.1**	**122.1**	**116.1**
Aviation	38.0		60.1		71.9	74.1	77.7	80.8	80.7
Commercial	*30.0*		*55.6*		*68.6*	*70.8*	*74.5*	*77.7*	*77.6*
Military	*8.1*		*4.5*		*3.3*	*3.3*	*3.2*	*3.1*	*3.1*
Marine	65.4		53.1		39.0	42.6	42.4	41.3	35.4
CH_4	**0.2**		**0.1**		**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Aviation[a]	0.0		0.0		0.0	0.0	0.0	0.0	0.0
Marine	0.2		0.1		0.1	0.1	0.1	0.1	0.1
N_2O	**0.9**		**1.0**		**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**		**112.0**	**117.7**	**121.3**	**123.3**	**117.2**

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

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

Table 3-105: CO_2, CH_4, and N_2O Emissions from International Bunker Fuels (kt)

Gas/Mode	1990		2005		2015	2016	2017	2018	2019
CO_2	**103,463**		**113,232**		**110,908**	**116,611**	**120,121**	**122,112**	**116,064**
Aviation	38,034		60,125		71,942	74,059	77,696	80,788	80,714
Marine	65,429		53,107		38,967	42,552	42,425	41,324	35,350
CH_4	**7**		**5**		**4**	**4**	**4**	**4**	**4**
Aviation[a]	0		0		0	0	0	0	0
Marine	7		5		4	4	4	4	4
N_2O	**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] CH_4 emissions from aviation are estimated to be zero.

Methodology

Emissions of CO_2 were estimated by applying C content and fraction oxidized factors to fuel consumption activity data. This approach is analogous to that described under Section 3 – CO_2 from Fossil Fuel Combustion. Carbon content and fraction oxidized factors for jet fuel, distillate fuel oil, and residual fuel oil are the same as used for CO_2 from Fossil Fuel Combustion and are presented in Annex 2.1, Annex 2.2, and Annex 3.8 of this Inventory. Density conversions were taken from Chevron (2000), ASTM (1989), and USAF (1998). Heat content for distillate fuel oil and residual fuel oil were taken from EIA (2020) and USAF (1998), and heat content for jet fuel was taken from EIA (2020).

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

Emission estimates for CH_4 and N_2O were calculated by multiplying emission factors by measures of fuel consumption by fuel type and mode. Emission factors used in the calculations of CH_4 and N_2O emissions were obtained from the *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997), which is also referenced in the *2006 IPCC Guidelines* (IPCC 2006). For aircraft emissions, the following value, in units of grams of pollutant per kilogram of fuel consumed (g/kg), was employed: 0.1 for N_2O (IPCC 2006). For marine vessels consuming either distillate diesel or residual fuel oil the following values (g/MJ), were employed: 0.315 for CH_4 and 0.08 for N_2O. Activity data for aviation included solely jet fuel consumption statistics, while the marine mode included both distillate diesel and residual fuel oil.

Activity data on domestic and international aircraft fuel consumption were developed by the U.S. Federal Aviation Administration (FAA) using radar-informed data from the FAA Enhanced Traffic Management System (ETMS) for 1990 and 2000 through 2019 as modeled with the Aviation Environmental Design Tool (AEDT). This bottom-up approach is built from modeling dynamic aircraft performance for each flight occurring within an individual calendar year. The analysis incorporates data on the aircraft type, date, flight identifier, departure time, arrival time, departure airport, arrival airport, ground delay at each airport, and real-world flight trajectories. To generate results for a given flight within AEDT, the radar-informed aircraft data is correlated with engine and aircraft performance data to calculate fuel burn and exhaust emissions. Information on exhaust emissions for in-production aircraft engines comes from the International Civil Aviation Organization (ICAO) Aircraft Engine Emissions Databank (EDB). This bottom-up approach is in accordance with the Tier 3B method from the *2006 IPCC Guidelines* (IPCC 2006).

International aviation CO_2 estimates for 1990 and 2000 through 2019 were obtained directly from FAA's AEDT model (FAA 2021). The radar-informed method that was used to estimate CO_2 emissions for commercial aircraft for 1990 and 2000 through 2019 was not possible for 1991 through 1999 because the radar dataset was not available for years prior to 2000. FAA developed Official Airline Guide (OAG) schedule-informed inventories modeled with AEDT and great circle trajectories for 1990, 2000, and 2010. Because fuel consumption and CO_2 emission estimates for years 1991 through 1999 are unavailable, consumption estimates for these years were calculated using fuel consumption estimates from the Bureau of Transportation Statistics (DOT 1991 through 2013), adjusted based on 2000 through 2005 data. See Annex 3.3 for more information on the methodology for estimating emissions from commercial aircraft jet fuel consumption.

Data on U.S. Department of Defense (DoD) aviation bunker fuels and total jet fuel consumed by the U.S. military was supplied by the Office of the Under Secretary of Defense (Installations and Environment), DoD. Estimates of the percentage of each Service's total operations that were international operations were developed by DoD. Military aviation bunkers included international operations, operations conducted from naval vessels at sea, and operations conducted from U.S. installations principally over international water in direct support of military operations at sea. Military aviation bunker fuel emissions were estimated using military fuel and operations data synthesized from unpublished data from DoD's Defense Logistics Agency Energy (DLA Energy 2020). Together, the data allow the quantity of fuel used in military international operations to be estimated. Densities for each jet fuel type were obtained from a report from the U.S. Air Force (USAF 1998). Final jet fuel consumption estimates are presented in Table 3-106. See Annex 3.8 for additional discussion of military data.

Table 3-106: 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	8,344
U.S. Military	862	462	341	333	326	315	318
Total	**4,084**	**6,445**	**7,725**	**7,943**	**8,338**	**8,667**	**8,662**

Note: Totals may not sum due to independent rounding.

In order to quantify the civilian international component of marine bunker fuels, activity data on distillate diesel and residual fuel oil consumption by cargo or passenger carrying marine vessels departing from U.S. ports were collected for individual shipping agents on a monthly basis by the U.S. Customs and Border Protection. This information was then reported in unpublished data collected by the Foreign Trade Division of the U.S. Department of Commerce's Bureau of the Census (DOC 1991 through 2020) for 1990 through 2001, 2007 through 2019, and the Department of Homeland Security's *Bunker Report* for 2003 through 2006 (DHS 2008). Fuel consumption data for 2002 was interpolated due to inconsistencies in reported fuel consumption data. Activity data on distillate diesel consumption by military vessels departing from U.S. ports were provided by DLA Energy (2020). The total amount of fuel provided to naval vessels was reduced by 21 percent to account for fuel used while the vessels were not-underway (i.e., in port). Data on the percentage of steaming hours underway versus not underway were provided by the U.S. Navy. These fuel consumption estimates are presented in Table 3-107.

Table 3-107: 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.

Uncertainty and Time-Series Consistency

Emission estimates related to the consumption of international bunker fuels are subject to the same uncertainties as those from domestic aviation and marine mobile combustion emissions; however, additional uncertainties result from the difficulty in collecting accurate fuel consumption activity data for international transport activities separate from domestic transport activities.[105] For example, smaller aircraft on shorter routes often carry sufficient fuel to complete several flight segments without refueling in order to minimize time spent at the airport gate or take advantage of lower fuel prices at particular airports. This practice, called tankering, when done on international flights, complicates the use of fuel sales data for estimating bunker fuel emissions. Tankering is less common with the type of large, long-range aircraft that make many international flights from the United States, however. Similar practices occur in the marine shipping industry where fuel costs represent a significant portion of overall operating costs and fuel prices vary from port to port, leading to some tankering from ports with low fuel costs.

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

Additionally, there are uncertainties in historical aircraft operations and training activity data. Estimates for the quantity of fuel actually used in Navy and Air Force flying activities reported as bunker fuel emissions had to be

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

estimated based on a combination of available data and expert judgment. Estimates of marine bunker fuel emissions were based on Navy vessel steaming hour data, which reports fuel used while underway and fuel used while not underway. This approach does not capture some voyages that would be classified as domestic for a commercial vessel. Conversely, emissions from fuel used while not underway preceding an international voyage are reported as domestic rather than international as would be done for a commercial vessel. There is uncertainty associated with ground fuel estimates for 1997 through 2019, including estimates for the quantity of jet fuel allocated to ground transportation. Small fuel quantities may have been used in vehicles or equipment other than that which was assumed for each fuel type.

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

Although aggregate fuel consumption data have been used to estimate emissions from aviation, the recommended method for estimating emissions of gases other than CO_2 in the *2006 IPCC Guidelines* (IPCC 2006) is to use data by specific aircraft type, number of individual flights and, ideally, movement data to better differentiate between domestic and international aviation and to facilitate estimating the effects of changes in technologies. The IPCC also recommends that cruise altitude emissions be estimated separately using fuel consumption data, while landing and take-off (LTO) cycle data be used to estimate near-ground level emissions of gases other than CO_2.[106]

There is also concern regarding the reliability of the existing DOC (1991 through 2019) data on marine vessel fuel consumption reported at U.S. customs stations due to the significant degree of inter-annual variation.

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

QA/QC and Verification

In order to ensure the quality of the emission estimates from international bunker fuels, General (IPCC Tier 1) and category-specific (Tier 2) Quality Assurance/Quality Control (QA/QC) procedures were implemented consistent with the U.S. Inventory QA/QC plan outlined in Annex 8. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and emission factor sources and methodology used for estimating CO_2, CH_4, and N_2O emissions from international bunker fuels in the United States. Emission totals for the different sectors and fuels were compared and trends were investigated. No corrective actions were necessary.

[106] 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.

Recalculations Discussion

EPA revised distillate fuel oil carbon contents, which affect marine distillate fuel oil consumption (EPA 2020). Revisions resulted in an average annual increase of less than 0.05 MMT CO_2 Eq. in emissions from marine residual and distillate fuel oil.

Planned Improvements

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

3.11 Wood Biomass and Biofuels Consumption (CRF Source Category 1A)

The combustion of biomass fuels—such as wood, charcoal, and wood waste and biomass-based fuels such as ethanol, biogas, and biodiesel—generates CO_2 in addition to CH_4 and N_2O already covered in this chapter. In line with the reporting requirements for inventories submitted under the UNFCCC, CO_2 emissions from biomass combustion have been estimated separately from fossil fuel CO_2 emissions and are not directly included in the energy sector contributions to U.S. totals. In accordance with IPCC methodological guidelines, any such emissions are calculated by accounting for net carbon fluxes from changes in biogenic C reservoirs in wooded or crop lands. For a more complete description of this methodological approach, see the Land Use, Land-Use Change, and Forestry chapter (Chapter 6), which accounts for the contribution of any resulting CO_2 emissions to U.S. totals within the Land Use, Land-Use Change, and Forestry sector's approach.

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

In 2019, total CO_2 emissions from the burning of woody biomass in the industrial, residential, commercial, and electric power sectors were approximately 216.5 MMT CO_2 Eq. (216,533 kt) (see Table 3-108 and Table 3-109). As the largest consumer of woody biomass, the industrial sector was responsible for 61.3 percent of the CO_2 emissions from this source. The residential sector was the second largest emitter, constituting 25.2 percent of the total, while the electric power and commercial sectors accounted for the remainder.

Table 3-108: CO_2 Emissions from Wood Consumption by End-Use Sector (MMT CO_2 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 3-109: CO_2 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 1,150.2 trillion Btu of ethanol (95 percent of total), and as a result, produced approximately 78.7 MMT CO_2 Eq. (78,739 kt) (see Table 3-110 and Table 3-111) of CO_2 emissions. Smaller quantities of ethanol were also used in the industrial and commercial sectors. Ethanol fuel production and consumption has grown significantly since 1990 due to the favorable economics of blending ethanol into gasoline and federal policies that have encouraged use of renewable fuels.

Table 3-110: CO_2 Emissions from Ethanol Consumption (MMT CO_2 Eq.)

End-Use Sector	1990	2005	2015	2016	2017	2018	2019
Transportation[a]	4.1	21.6	74.2	76.9	77.7	78.6	78.7
Industrial	0.1	1.2	1.9	1.8	1.9	1.4	1.6
Commercial	0.1	0.2	2.8	2.6	2.5	1.9	2.2
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-81 for additional information on transportation consumption of these fuels.

Table 3-111: CO_2 Emissions from Ethanol Consumption (kt)

End-Use Sector	1990	2005	2015	2016	2017	2018	2019
Transportation[a]	4,059	21,616	74,187	76,903	77,671	78,603	78,739
Industrial	105	1,176	1,931	1,789	1,868	1,404	1,627
Commercial	63	151	2,816	2,558	2,550	1,910	2,212
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-81 for additional information on transportation consumption of these fuels.

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

In 2019, the United States consumed an estimated 231.3 trillion Btu of biodiesel, and as a result, produced approximately 17.1 MMT CO_2 Eq. (17,080 kt) (see Table 3-112 and Table 3-113) of CO_2 emissions. Biodiesel production and consumption has grown significantly since 2001 due to the favorable economics of blending biodiesel into diesel and federal policies that have encouraged use of renewable fuels (EIA 2020b). There was no measured biodiesel consumption prior to 2001 EIA (2020).

Table 3-112: CO_2 Emissions from Biodiesel Consumption (MMT CO_2 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-81 for additional information on transportation consumption of these fuels.

Table 3-113: CO_2 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-81 for additional information on transportation consumption of these fuels.

Methodology

Woody biomass emissions were estimated by applying two gross heat contents from EIA (Lindstrom 2006) to U.S. consumption data (EIA 2020) (see Table 3-114), provided in energy units for the industrial, residential, commercial, and electric power sectors. One heat content (16.95 MMBtu/MT wood and wood waste) was applied to the industrial sector's consumption, while the other heat content (15.43 MMBtu/MT wood and wood waste) was applied to the consumption data for the other sectors. An EIA emission factor of 0.434 MT C/MT wood (Lindstrom 2006) was then applied to the resulting quantities of woody biomass to obtain CO_2 emission estimates. The woody biomass is assumed to contain black liquor and other wood wastes, have a moisture content of 12 percent, and undergo complete combustion to be converted into CO_2.

The amount of ethanol allocated across the transportation, industrial, and commercial sectors was based on the sector allocations of ethanol-blended motor gasoline. The sector allocations of ethanol-blended motor gasoline were determined using a bottom-up analysis conducted by EPA, as described in the Methodology section of Fossil Fuel Combustion. Total U.S. ethanol consumption from EIA (2020) was allocated to individual sectors using the same sector allocations as ethanol-blended motor gasoline. The emissions from ethanol consumption were calculated by applying an emission factor of 18.67 MMT C/Qbtu (EPA 2010) to adjusted ethanol consumption estimates (see Table 3-115). The emissions from biodiesel consumption were calculated by applying an emission factor of 20.1 MMT C/Qbtu (EPA 2010) to U.S. biodiesel consumption estimates that were provided in energy units (EIA 2020) (see Table 3-116).[107]

Table 3-114: 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.

Table 3-115: Ethanol Consumption by Sector (Trillion Btu)

End-Use Sector	1990		2005		2015	2016	2017	2018	2019
Transportation	59.3		315.8		1,083.7	1,123.4	1,134.6	1,148.2	1,150.2
Industrial	1.5		17.2		28.2	26.1	27.3	20.5	23.8
Commercial	0.9		2.2		41.1	37.4	37.2	27.9	32.3
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.

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

Table 3-116: 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)

Uncertainty and Time-Series Consistency

It is assumed that the combustion efficiency for woody biomass is 100 percent, which is believed to be an overestimate of the efficiency of wood combustion processes in the United States. Decreasing the combustion efficiency would decrease emission estimates for CO_2. Additionally, the heat content applied to the consumption of woody biomass in the residential, commercial, and electric power sectors is unlikely to be a completely accurate representation of the heat content for all the different types of woody biomass consumed within these sectors. Emission estimates from ethanol and biodiesel production are more certain than estimates from woody biomass consumption due to better activity data collection methods and uniform combustion techniques.

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

Recalculations Discussion

EIA (2020) revised approximate heat rates for electricity and the heat content of electricity for noncombustible renewable energy, which impacted wood energy consumption by the industrial sector from 2016 through 2018. Revisions to biomass consumption resulted in an average annual decrease of 0.7 MMT CO_2 Eq. (0.3 percent).

Planned Improvements

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

The availability of facility-level combustion emissions through EPA's GHGRP will be examined to help better characterize the industrial sector's energy consumption in the United States, and further classify woody biomass consumption by business establishments according to industrial economic activity type. Most methodologies used in EPA's GHGRP are consistent with IPCC, though for EPA's GHGRP, facilities collect detailed information specific to their operations according to detailed measurement standards, which may differ with the more aggregated data collected for the Inventory to estimate total, national U.S. emissions. In addition, and unlike the reporting requirements for this chapter under the UNFCCC reporting guidelines, some facility-level fuel combustion emissions reported under EPA's GHGRP may also include industrial process emissions.[108]

In line with UNFCCC reporting guidelines, fuel combustion emissions are included in this chapter, while process emissions are included in the Industrial Processes and Product Use chapter of this report. In examining data from EPA's GHGRP that would be useful to improve the emission estimates for the CO_2 from biomass combustion category, particular attention will also be made to ensure time series consistency, as the facility-level reporting data from EPA's GHGRP are not available for all inventory years as reported in this Inventory. Additionally, analyses will focus on aligning reported facility-level fuel types and IPCC fuel types per the national energy statistics, ensuring CO_2 emissions from biomass are separated in the facility-level reported data, and maintaining consistency with national energy statistics provided by EIA. In implementing improvements and integration of data from EPA's

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

GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will be relied upon.[109]

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

Carbon dioxide emissions from biomass used in the electric power sector are calculated using woody biomass consumption data from EIA's *Monthly Energy Review* (EIA 2020a), whereas non-CO_2 biomass emissions from the electric power sector are estimated by applying technology and fuel use data from EPA's Clean Air Market Acid Rain Program dataset (EPA 2021) to fuel consumption data from EIA (2020a). There were significant discrepancies identified between the EIA woody biomass consumption data and the consumption data estimated using EPA's Acid Rain Program dataset (see the Methodology section for CH_4 and N_2O from Stationary Combustion). EPA will continue to investigate this discrepancy in order to apply a consistent approach to both CO_2 and non-CO_2 emission calculations for woody biomass consumption in the electric power sector.

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