3 Energy

3 Energy

Energy-related activities were the primary sources of U.S. anthropogenic greenhouse gas emissions, accounting for 81.5 percent of total gross greenhouse gas emissions on a carbon dioxide (CO_2) equivalent basis in 2023.[1] This included 96.4, 39.6, and 9.3 percent of the nation's CO_2, methane (CH_4), and nitrous oxide (N_2O) emissions, respectively.[2] Energy-related CO_2 emissions alone constituted 76.5 percent of total gross 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 gross national emissions (5.0 percent collectively).

Emissions from fossil fuel combustion contribute 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 33,809 million metric tons (MMT) of CO_2 were added to the atmosphere through the combustion of fossil fuels in 2023, of which the United States accounted for approximately 13 percent.[3] Due to their relative importance over time (see Figure 3-2), fossil fuel combustion-related CO_2 emissions are considered in more detail than other energy-related emissions in this report (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.

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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 The contribution of energy non-CO_2 emissions is based on gross totals so excludes LULUCF methane (CH_4) and nitrous oxide (N_2O) emissions. The contribution of energy-related methane (CH_4) and (N_2O) including LULUCF non-CO_2 emissions, is 37.1 percent and 9.8 percent respectively.

3 Global CO_2 emissions from fossil fuel combustion were taken from International Energy Agency *Global energy-related CO_2 emissions, 2023.* Available at: https://iea.blob.core.windows.net/assets/33e2badc-b839-4c18-84ce-f6387b3c008f/CO2Emissionsin2023.pdf (IEA 2023).

Figure 3-1: 2023 Energy Sector Greenhouse Gas Sources

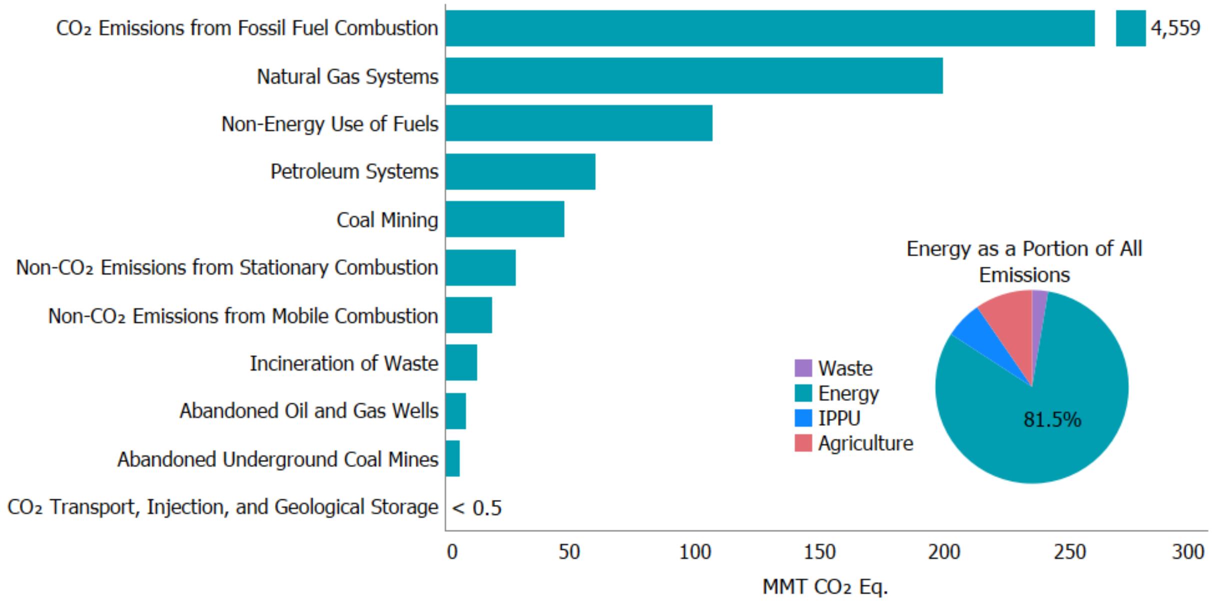

Figure 3-2: Trends in Energy Sector Greenhouse Gas Sources

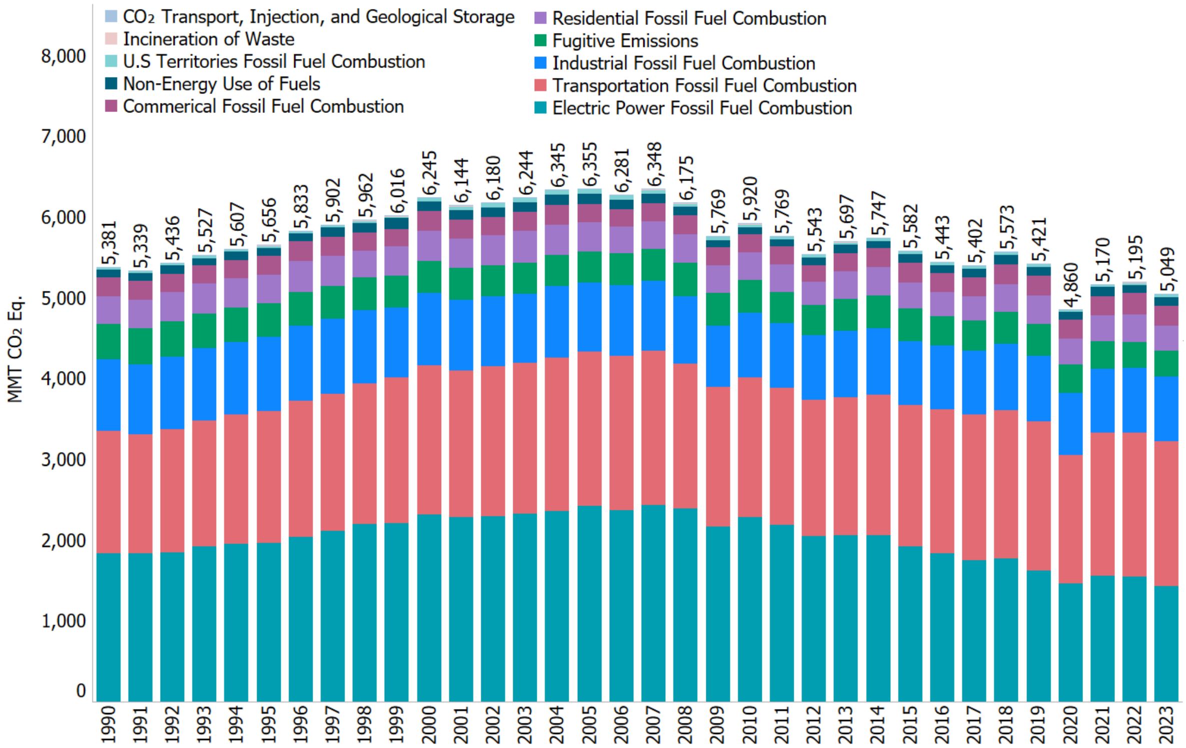

Figure 3-3: 2023 U.S. Fossil Carbon Flows (MMT CO_2 Eq.)

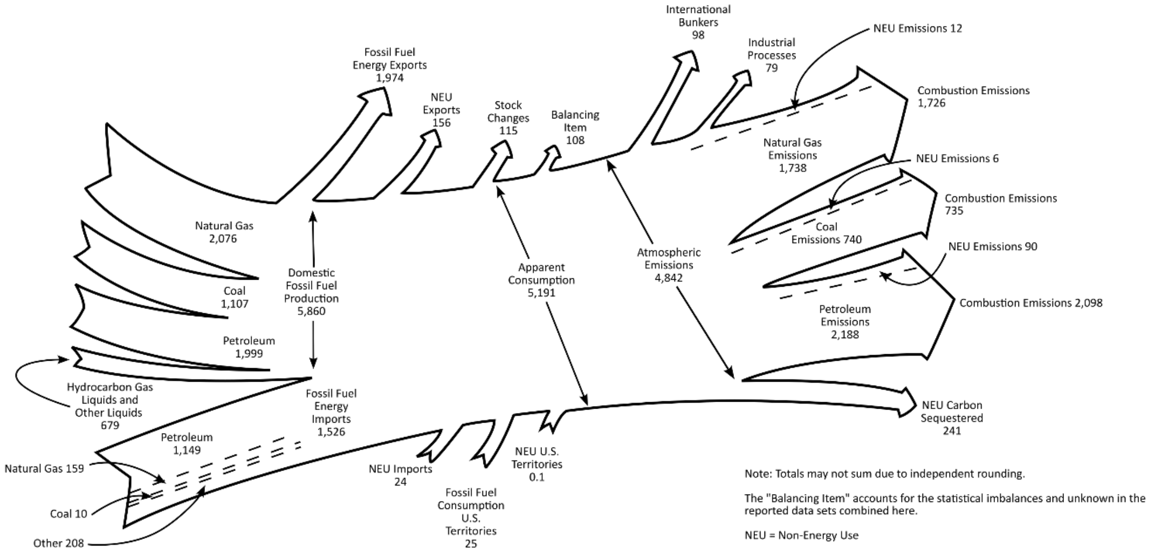

Table 3-1 summarizes emissions from the Energy sector in units of MMT CO_2 Eq., while unweighted gas emissions in kilotons (kt) are provided in Table 3-2. Overall, emissions due to energy-related activities were 5,050.4 MMT CO_2 Eq. in 2023,[4] a decrease of 6.2 percent since 1990 and a decrease of 2.8 percent since 2022. Trends are driven by a number of factors including a shift from coal to natural gas and renewables in the electric power sector.

[4] This *Inventory* report presents CO_2 equivalent values based on the IPCC *Fifth Assessment Report* (AR5) GWP values. See Chapter 1, Introduction for more information.

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

Gas/Source	1990	2005	2019	2020	2021	2022	2023
CO_2	**4,911.0**	**5,923.1**	**5,059.2**	**4,521.0**	**4,841.2**	**4,878.0**	**4,742.3**
Fossil Fuel Combustion	4,752.2	5,744.1	4,852.6	4,342.3	4,654.6	4,702.8	4,559.4
Transportation	*1,468.9*	*1,858.6*	*1,816.6*	*1,573.0*	*1,753.5*	*1,753.6*	*1,776.5*
Electricity Generation	*1,820.0*	*2,400.1*	*1,606.7*	*1,439.6*	*1,540.9*	*1,531.7*	*1,414.2*
Industrial	*876.5*	*847.6*	*809.8*	*763.4*	*780.5*	*799.7*	*792.6*
Residential	*338.6*	*358.9*	*342.9*	*314.8*	*318.0*	*335.2*	*307.1*
Commercial	*228.3*	*227.1*	*251.7*	*229.3*	*237.5*	*259.2*	*244.2*
U.S. Territories	*20.0*	*51.9*	*24.8*	*22.3*	*24.1*	*23.5*	*24.9*
Non-Energy Use of Fuels	99.1	125.0	106.5	97.9	111.7	101.7	107.1
Natural Gas Systems	32.5	26.3	38.7	36.8	35.7	36.4	37.7
Petroleum Systems	9.6	10.2	45.4	28.9	24.1	22.1	23.3
Incineration of Waste	12.9	13.3	12.9	12.9	12.5	12.5	12.4
Coal Mining	4.6	4.2	3.0	2.2	2.5	2.5	2.4
CO_2 Transport, Injection, and Geological and Storage	0.0	0.0	+	+	0.1	0.1	0.1
Abandoned Oil and Gas Wells	+	+	+	+	+	+	+
Biomass-Wood[a]	*215.2*	*206.9*	*216.7*	*189.5*	*191.5*	*194.3*	*187.7*
International Bunker Fuels[b]	*103.6*	*113.3*	*113.6*	*69.6*	*80.2*	*98.2*	*96.2*
Biofuels-Ethanol[a]	*4.2*	*22.9*	*82.6*	*71.8*	*79.1*	*79.6*	*80.7*
Biofuels-Biodiesel[a]	*0.0*	*0.9*	*17.1*	*17.7*	*16.1*	*15.6*	*18.2*
Biomass-MSW[a]	*18.5*	*14.7*	*15.7*	*15.6*	*15.3*	*14.9*	*13.9*
CH_4	**410.4**	**360.2**	**320.4**	**302.3**	**289.6**	**278.7**	**271.9**
Natural Gas Systems	219.6	210.7	189.0	180.1	174.6	172.8	162.4
Coal Mining	108.1	71.5	53.0	46.2	44.7	43.6	45.4
Petroleum Systems	50.0	48.4	50.8	50.6	45.1	36.3	38.0
Stationary Combustion	9.7	8.8	9.8	7.9	7.9	8.7	8.8
Abandoned Oil and Gas Wells	7.8	8.2	8.5	8.5	8.6	8.5	8.5
Abandoned Underground Coal Mines	8.1	7.4	6.6	6.5	6.2	6.1	6.1
Mobile Combustion	7.2	5.2	2.8	2.5	2.6	2.6	2.5
Incineration of Waste	+	+	+	+	+	+	+
International Bunker Fuels[b]	*0.2*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*
N_2O	**60.5**	**72.9**	**41.3**	**36.9**	**39.3**	**39.6**	**36.2**
Stationary Combustion	22.3	30.5	22.1	20.5	22.0	22.6	19.6
Mobile Combustion	37.8	42.0	18.7	16.0	16.8	16.6	16.2
Incineration of Waste	0.4	0.3	0.4	0.3	0.4	0.3	0.3
Petroleum Systems	+	+	+	+	+	+	+
Natural Gas Systems	+	+	+	+	+	+	+
International Bunker Fuels[b]	*0.8*	*0.9*	*0.9*	*0.5*	*0.6*	*0.8*	*0.8*
Total	**5,381.9**	**6,356.2**	**5,420.9**	**4,860.2**	**5,170.1**	**5,196.2**	**5,050.4**

+ Does not exceed 0.05 MMT CO_2 Eq.

[a] Emissions from biomass and biofuel 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*.

Note: Totals may not sum due to independent rounding.

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

Gas/Source	1990	2005	2019	2020	2021	2022	2023
CO_2	**4,910,974**	**5,923,104**	**5,059,240**	**4,521,041**	**4,841,186**	**4,877,978**	**4,742,336**
Fossil Fuel Combustion	4,752,234	5,744,138	4,852,647	4,342,309	4,654,629	4,702,769	4,559,379
Non-Energy Use of Fuels	99,104	124,988	106,487	97,881	111,718	101,697	107,069
Natural Gas Systems	32,525	26,325	38,696	36,810	35,745	36,410	37,682
Petroleum Systems	9,597	10,222	45,445	28,876	24,091	22,084	23,272
Incineration of Waste	12,900	13,254	12,948	12,921	12,476	12,484	12,425
Coal Mining	4,606	4,169	2,992	2,197	2,455	2,474	2,404
CO_2 Transport, Injection, and Geological and Storage	0	0	18	39	65	53	98
Abandoned Oil and Gas Wells	7	7	8	8	8	8	8
Biomass-Wood[a]	*215,186*	*206,901*	*216,652*	*189,516*	*191,471*	*194,318*	*187,690*
International Bunker Fuels[b]	*103,634*	*113,328*	*113,632*	*69,638*	*80,180*	*98,241*	*96,160*
Biofuels-Ethanol[a]	*4,227*	*22,943*	*82,578*	*71,848*	*79,064*	*79,593*	*80,708*
Biofuels-Biodiesel[a]	*0*	*856*	*17,080*	*17,678*	*16,112*	*15,622*	*18,185*
Biomass-MSW[a]	*18,534*	*14,722*	*15,709*	*15,614*	*15,329*	*14,864*	*13,936*
CH_4	**14,659**	**12,864**	**11,443**	**10,795**	**10,344**	**9,952**	**9,709**
Natural Gas Systems	7,842	7,525	6,751	6,431	6,236	6,173	5,802
Coal Mining	3,860	2,552	1,892	1,648	1,595	1,558	1,623
Petroleum Systems	1,787	1,730	1,813	1,807	1,611	1,295	1,358
Stationary Combustion	345	313	349	282	284	312	313
Abandoned Oil and Gas Wells	279	294	302	303	306	303	303
Abandoned Underground Coal Mines	288	264	237	232	221	218	219
Mobile Combustion	258	187	101	90	91	92	91
Incineration of Waste	+	+	+	+	+	+	+
International Bunker Fuels[b]	*7*	*5*	*4*	*3*	*3*	*3*	*3*
N_2O	**228**	**275**	**156**	**139**	**148**	**149**	**136**
Stationary Combustion	84	115	84	77	83	85	74
Mobile Combustion	143	158	71	60	64	63	61
Incineration of Waste	2	1	1	1	1	1	1
Petroleum Systems	+	+	+	+	+	+	+
Natural Gas Systems	+	+	+	+	+	+	+
International Bunker Fuels[b]	*3*	*3*	*3*	*2*	*2*	*3*	*3*

+ Does not exceed 0.5 kt.

[a] Emissions from biomass and biofuel 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*.

Note: Totals by gas may not sum due to independent rounding.

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 tribal lands and 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 biomass 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 2022) to ensure that the trend is accurate. Key updates in this year's *Inventory* include new data on the activity of battery and plug-in hybrid electric vehicles, the incorporation of MOVES5 output data to replace MOVES3, updated values for natural gas and petroleum consumed by all sectors and U.S. Territories for the years 2020 through 2022, updated electricity statistics which affected commercial sector wood consumption for the years 2014 through 2022, updates for offshore production sources in Gulf of America federal and state waters, and revisions to GHGRP data submissions. The impact of these recalculations averaged an increase of 6.4 MMT CO_2 Eq. (0.1 percent) per year across the time series. For more information on specific methodological updates, please see the Recalculations Discussion section for each category in this chapter.

Box 3-1: Uses of EPA's Greenhouse Gas Reporting Program Energy Data

EPA's Greenhouse Gas Reporting Program (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 3-2 of this chapter, and Sections 3.3 Incineration of Waste, 3.4 Coal Mining, 3.6 Petroleum Systems, 3.7 Natural Gas Systems 3.9 CO_2 Transport, Injection and Storage, and 3.11 Biomass and Biofuels Consumption). 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 for national inventory reporting. 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 (Sections 3.3 Incineration of Waste, 3.4 Coal Mining, 3.6 Petroleum Systems, 3.7 Natural Gas Systems, 3.9 CO_2 Transport, Injection and Storage, and 3.11 Biomass and Biofuels Consumption), 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 data tables (see Box 3-2). The industrial end-use sector activity data collected for the Inventory (EIA 2024) 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 (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 sector: electric power, industrial, residential, commercial, U.S. Territories, and transportation.

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	2019	2020	2021	2022	2023
CO_2	4,752.2	5,744.1	4,852.6	4,342.3	4,654.6	4,702.8	4,559.4
CH_4	16.9	14.0	12.6	10.4	10.5	11.3	11.3
N_2O	60.1	72.5	40.9	36.6	38.9	39.2	35.8
Total	**4,829.2**	**5,830.6**	**4,906.1**	**4,389.3**	**4,704.0**	**4,753.2**	**4,606.5**

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	2019	2020	2021	2022	2023
CO_2	4,752,234	5,744,138	4,852,647	4,342,309	4,654,629	4,702,769	4,559,379
CH_4	603	501	449	372	375	404	404
N_2O	227	274	154	138	146	148	135

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 2023, CO_2 emissions from fossil fuel combustion decreased by 3.1 percent relative to the previous year and were 4.1 percent below emissions in 1990 (as shown in Table 3-6). The decrease in CO_2 emissions from fossil fuel combustion was a result of a 1.9 percent decrease in fossil fuel energy use. Carbon dioxide emissions from coal consumption decreased by 18.3 percent (164.1 MMT CO_2 Eq.) from 2022 to 2023. While carbon dioxide emissions from natural gas use increased by 1.0 percent (17.6 MMT CO_2 Eq.) and emissions from petroleum use increased by 0.2 percent (3.1 MMT CO_2 Eq.) from 2022 to 2023. The increase in natural gas consumption and associated emissions in 2023 is observed mostly in the electric power and industrial sectors, the increase in petroleum use is mainly in the transportation sector, while the coal decrease is mainly due to reduced use in the electric power sector. In 2023, CO_2 emissions from fossil fuel combustion were 4,559.4 MMT CO_2 Eq. (see Table 3-5).[5]

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

Fuel/Sector	1990	2005	2019	2020	2021	2022	2023
Coal	**1,719.8**	**2,113.7**	**1,028.1**	**835.6**	**957.4**	**898.8**	**734.7**
Residential	3.0	0.8	NO	NO	NO	NO	NO
Commercial	12.0	9.3	1.6	1.4	1.4	1.4	1.1
Industrial	157.8	117.8	49.4	43.0	43.0	43.0	36.5
Transportation	NO	NO	NO	NO	NO	NO	NO
Electric Power	1546.5	1982.8	973.5	788.2	910.1	851.5	694.6
U.S. Territories	0.5	3.0	3.6	3.1	2.9	2.9	2.5
Natural Gas	**998.6**	**1,166.2**	**1,649.3**	**1,617.2**	**1,622.1**	**1,708.2**	**1,725.8**
Residential	237.8	262.2	275.5	256.4	258.6	272.0	247.5
Commercial	142.0	162.9	192.9	173.5	180.4	192.3	182.8
Industrial	407.4	387.8	501.5	491.1	501.2	509.5	514.8
Transportation	36.0	33.1	58.9	58.8	65.2	72.3	71.7
Electric Power	175.4	318.9	616.6	634.8	612.8	659.3	704.5
U.S. Territories	NO	1.3	3.8	2.6	3.9	2.7	4.5
Petroleum	**2,033.3**	**2,463.8**	**2,174.9**	**1,889.1**	**2,074.8**	**2,095.3**	**2,098.5**
Residential	97.8	95.9	67.4	58.4	59.4	63.2	59.6
Commercial	74.3	54.9	57.2	54.4	55.7	65.4	60.2
Industrial	311.2	342.0	258.9	229.3	236.3	247.1	241.3
Transportation	1,432.9	1,825.5	1,757.7	1,514.2	1,688.4	1,681.2	1,704.7
Electric Power	97.5	98.0	16.2	16.2	17.7	20.5	14.7
U.S. Territories	19.5	47.6	17.5	16.6	17.3	17.8	17.9
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

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

Fuel/Sector	1990	2005	2019	2020	2021	2022	2023
Total	**4,752.2**	**5,744.1**	**4,852.6**	**4,342.3**	**4,654.6**	**4,702.8**	**4,559.4**

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.

Note: Totals may not sum due to independent rounding.

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

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

Table 3-6: Annual Change in CO_2 Emissions and Total 2023 CO_2 Emissions from Fossil Fuel Combustion for Selected Fuels and Sectors (MMT CO_2 Eq. and Percent)

Sector	Fuel Type	2019 to 2020		2020 to 2021		2021 to 2022		2022 to 2023		Total 2023
Transportation	Petroleum	-243.5	-13.9%	174.2	11.5%	-7.1	-0.4%	23.5	1.4%	1,704.7
Electric Power	Coal	-185.4	-19.0%	121.9	15.5%	-58.6	-6.4%	-156.9	-18.4%	694.6
Electric Power	Natural Gas	18.2	3.0%	-22.1	-3.5%	46.5	7.6%	45.2	6.9%	704.5
Industrial	Natural Gas	-10.4	-2.1%	10.0	2.0%	8.3	1.7%	5.3	1.0%	514.8
Residential	Natural Gas	-19.1	-6.9%	2.3	0.9%	13.3	5.2%	-24.5	-9.0%	247.5
Commercial	Natural Gas	-19.5	-10.1%	6.9	4.0%	12.0	6.6%	-9.5	-5.0%	182.8
Transportation	**All Fuels[a]**	**-243.7**	**-13.4%**	**180.6**	**11.5%**	**0.0**	**0.0%**	**22.9**	**1.3%**	**1,776.5**
Electric Power	**All Fuels[a]**	**-167.2**	**-10.4%**	**101.4**	**7.0%**	**-9.3**	**-0.6%**	**-117.5**	**-7.7%**	**1,414.2**
Industrial	**All Fuels[a]**	**-46.4**	**-5.7%**	**17.1**	**2.2%**	**19.2**	**2.5%**	**-7.1**	**-0.9%**	**792.6**
Residential	**All Fuels[a]**	**-28.1**	**-8.2%**	**3.2**	**1.0%**	**17.1**	**5.4%**	**-28.1**	**-8.4%**	**307.1**
Commercial	**All Fuels[a]**	**-22.5**	**-8.9%**	**8.3**	**3.6%**	**21.7**	**9.1%**	**-15.0**	**-5.8%**	**244.2**
All Sectors[a,b]	**All Fuels[a]**	**-510.3**	**-10.5%**	**312.3**	**7.2%**	**48.1**	**1.0%**	**-143.4**	**-3.1%**	**4,559.4**

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

[b] Includes U.S. Territories.

[6] 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.

Note: Totals may not sum due to independent rounding.

As shown in Table 3-6, recent trends in CO_2 emissions from fossil fuel combustion show a 10.5 percent decrease from 2019 to 2020, a 7.2 percent increase from 2020 to 2021, a 1.0 percent increase from 2021 to 2022, and a 3.1 percent decrease from 2022 to 2023. These changes contributed to an overall 6.0 percent decrease in CO_2 emissions from fossil fuel combustion from 2019 to 2023.

Recent trends in CO_2 emissions from fossil fuel combustion are largely driven by the electric power sector, which until 2017 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 2024c). Total net electric power generation from all fossil and non-fossil sources decreased by 2.9 percent from 2019 to 2020, increased by 2.7 percent from 2020 to 2021, increased by 3.0 percent from 2021 to 2022, and decreased by 1.1 percent from 2022 to 2023 (EIA 2025a). Carbon dioxide emissions from the electric power sector decreased from 2022 to 2023 by 7.7 percent due to increased production and use of natural gas and decreased production and use of coal for electric power generation. Carbon dioxide emissions from coal consumption for electric power generation decreased by 28.7 percent overall since 2019, including an 18.4 percent decrease from 2022 to 2023.

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 2023. Emissions from petroleum consumption for transportation have decreased by 3.0 percent since 2019, even as there was a less than 0.05 percent increase in VMT over the same time period. As of 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, 82.6 percent of the energy used in 2023 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 37.8 percent of total U.S. energy used in 2023. Natural gas and coal followed in order of fossil fuel energy demand significance, accounting for approximately 35.9 percent and 8.7 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 2025a). The remaining portion of energy used in 2023 was supplied by nuclear electric power (8.6 percent) and by a variety of renewable energy sources (8.89 percent), primarily wind energy, hydroelectric power, solar, geothermal and biomass (EIA 2025a).[7]

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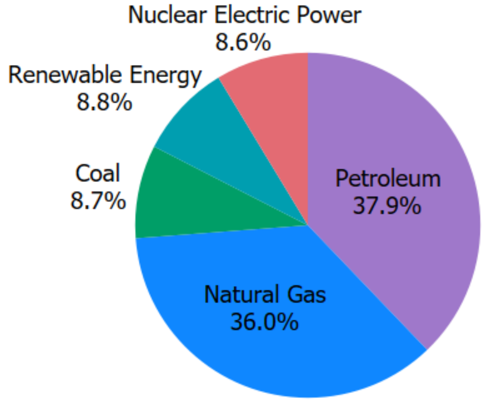
7 Renewable energy, as defined in EIA's energy statistics, includes the following energy sources: hydroelectric power, geothermal energy, biomass, solar energy, and wind energy.

Figure 3-4: 2023 U.S. Energy Use by Energy Source



Note: Totals may not sum due to independent rounding.

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

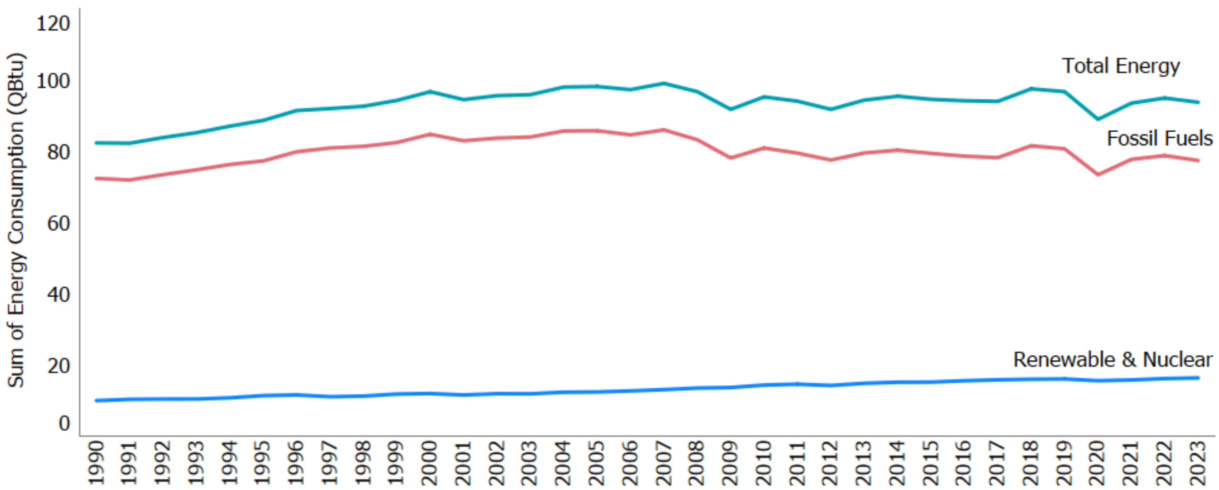
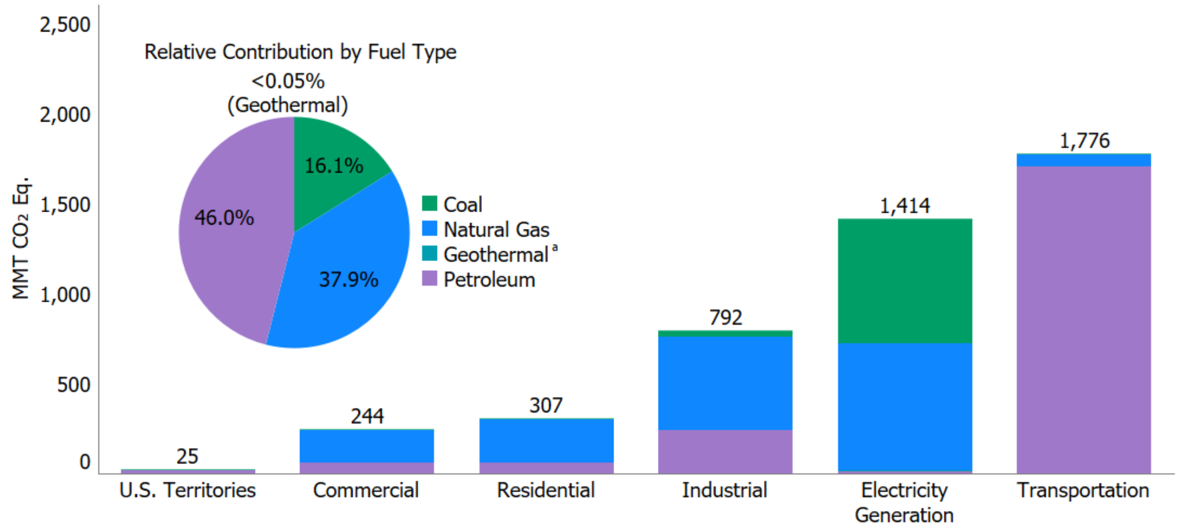


Figure 3-6: 2023 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type



[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.

Fossil fuels are generally combusted for the purpose of producing energy for useful heat and work. During the combustion process, the carbon 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).[8] These other carbon-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 that all of the carbon in fossil fuels used to produce energy is eventually converted to atmospheric CO_2.

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)[9] of nuclear power plants in 2023 remained high at 92 percent. In 2023, nuclear power represented 19 percent of total electricity generation. Since 1990, the wind and solar power sectors have shown strong growth and have become relatively important sources of electricity. Between 1990 and 2023, renewable energy generation (in kWh) from solar and wind energy have increased from 0.1 percent in 1990 to 14 percent of total electricity generation in 2023, 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 the Methodology section of CO_2 from Fossil Fuel Combustion). In addition to CO_2 emissions, CH_4 and N_2O are emitted from fossil fuel combustion as

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

9 The capacity factor equals actual generation divided by maximum potential generation based on net summer capacity. Net 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)" (EIA 2024g). Data for both the generation and net summer capacity are from EIA (2024a).

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 linked to the type of fuel being combusted as well as the combustion technology (see the 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	2019	2020	2021	2022	2023
Electric Power	**1,820.0**	**2,400.1**	**1,606.7**	**1,439.6**	**1,540.9**	**1,531.7**	**1,414.2**
Coal	1546.5	1982.8	973.5	788.2	910.1	851.5	694.6
Natural Gas	175.4	318.9	616.6	634.8	612.8	659.3	704.5
Fuel Oil	97.5	98.0	16.2	16.2	17.7	20.5	14.7
Geothermal	0.5	0.5	0.4	0.4	0.4	0.4	0.4
Industrial	**876.5**	**847.6**	**809.8**	**763.4**	**780.5**	**799.7**	**792.6**
Coal	157.8	117.8	49.4	43.0	43.0	43.0	36.5
Natural Gas	407.4	387.8	501.5	491.1	501.2	509.5	514.8
Fuel Oil	311.2	342.0	258.9	229.3	236.3	247.1	241.3
Residential	**338.6**	**358.9**	**342.9**	**314.8**	**318.0**	**335.2**	**307.1**
Coal	3.0	0.8	NO	NO	NO	NO	NO
Natural Gas	237.8	262.2	275.5	256.4	258.6	272.0	247.5
Fuel Oil	97.8	95.9	67.4	58.4	59.4	63.2	59.6
Commercial	**228.3**	**227.1**	**251.7**	**229.3**	**237.5**	**259.2**	**244.2**
Coal	12.0	9.3	1.6	1.4	1.4	1.4	1.1
Natural Gas	142.0	162.9	192.9	173.5	180.4	192.3	182.8
Fuel Oil	74.3	54.9	57.2	54.4	55.7	65.4	60.2
U.S. Territories	**20.0**	**51.9**	**24.8**	**22.3**	**24.1**	**23.5**	**24.9**
Coal	0.5	3.0	3.6	3.1	2.9	2.9	2.5
Natural Gas	NO	1.3	3.8	2.6	3.9	2.7	4.5
Fuel Oil	19.5	47.6	17.5	16.6	17.3	17.8	17.9
Total	**3,283.3**	**3,885.6**	**3,036.0**	**2,769.4**	**2,901.1**	**2,949.2**	**2,782.9**

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

Table 3-8: CH_4 Emissions from Stationary Combustion (MMT CO_2 Eq.)

Sector/Fuel Type	1990	2005	2019	2020	2021	2022	2023
Electric Power	**0.5**	**1.0**	**1.4**	**1.4**	**1.4**	**1.5**	**1.5**
Coal	0.4	0.4	0.2	0.2	0.2	0.2	0.2
Fuel Oil	0.0	0.0	+	+	+	+	+
Natural gas	0.1	0.5	1.2	1.2	1.2	1.3	1.3
Wood	0.0	0.0	+	+	+	+	+
Industrial	**2.1**	**1.9**	**1.7**	**1.6**	**1.6**	**1.6**	**1.5**
Coal	0.5	0.3	0.1	0.1	0.1	0.1	0.1
Fuel Oil	0.2	0.2	0.2	0.1	0.1	0.2	0.1
Natural gas	0.2	0.2	0.3	0.2	0.3	0.3	0.3
Wood	1.2	1.2	1.1	1.1	1.1	1.0	1.0

Sector/Fuel Type	1990	2005	2019	2020	2021	2022	2023
Commercial	**1.2**	**1.2**	**1.3**	**1.2**	**1.3**	**1.3**	**1.3**
Coal	0.0	0.0	+	+	+	+	+
Fuel Oil	0.3	0.2	0.2	0.2	0.2	0.3	0.2
Natural gas	0.4	0.4	0.5	0.4	0.5	0.5	0.5
Wood	0.5	0.6	0.6	0.6	0.6	0.6	0.6
Residential	**5.9**	**4.5**	**5.3**	**3.6**	**3.6**	**4.3**	**4.5**
Coal	0.3	0.1	NO	NO	NO	NO	NO
Fuel Oil	0.4	0.4	0.3	0.2	0.2	0.3	0.2
Natural Gas	0.6	0.7	0.7	0.6	0.6	0.7	0.6
Wood	4.6	3.4	4.4	2.8	2.7	3.4	3.6
U.S. Territories	**0.0**	**0.1**	**+**	**+**	**+**	**+**	**+**
Coal	0.0	0.0	+	+	+	+	+
Fuel Oil	0.0	0.1	+	+	+	+	+
Natural Gas	NO	0.0	+	+	+	+	+
Wood	NE	NE	NE	NE	NE	NE	NE
Total	**9.7**	**8.8**	**9.8**	**7.9**	**7.9**	**8.7**	**8.8**

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

Table 3-9: N_2O Emissions from Stationary Combustion (MMT CO_2 Eq.)

Sector/Fuel Type	1990	2005	2019	2020	2021	2022	2023
Electric Power	**18.2**	**26.7**	**18.8**	**17.5**	**19.0**	**19.4**	**16.6**
Coal	17.9	24.9	14.8	13.5	15.1	15.2	12.1
Fuel Oil	0.1	0.1	+	+	+	+	+
Natural Gas	0.3	1.7	3.9	4.0	3.9	4.2	4.4
Wood	+	+	+	+	+	+	+
Industrial	**2.8**	**2.6**	**2.2**	**2.0**	**2.1**	**2.0**	**1.9**
Coal	0.7	0.5	0.2	0.2	0.2	0.2	0.2
Fuel Oil	0.5	0.5	0.3	0.3	0.3	0.3	0.3
Natural Gas	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Wood	1.5	1.5	1.4	1.4	1.4	1.3	1.2
Commercial	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**
Coal	+	+	+	+	+	+	+
Fuel Oil	0.2	0.1	0.1	0.1	0.1	0.1	0.1
Natural Gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wood	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Residential	**0.9**	**0.8**	**0.8**	**0.6**	**0.6**	**0.7**	**0.7**
Coal	+	+	NO	NO	NO	NO	NO
Fuel Oil	0.2	0.2	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	0.6	0.4	0.5	0.3	0.3	0.4	0.5

Sector/Fuel Type	1990	2005	2019	2020	2021	2022	2023
U.S. Territories	**+**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Coal	+	+	+	+	+	+	+
Fuel Oil	+	0.1	+	+	+	+	+
Natural Gas	NO	+	+	+	+	+	+
Wood	NE	NE	NE	NE	NE	NE	NE
Total	**22.3**	**30.5**	**22.1**	**20.5**	**22.0**	**22.6**	**19.6**

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

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	2019	2020	2021	2022	2023
Transportation	**1,513.9**	**1,905.8**	**1,838.2**	**1,591.5**	**1,772.9**	**1,772.7**	**1,795.2**
CO_2	1,468.9	1,858.6	1,816.6	1,573.0	1,753.5	1,753.6	1,776.5
CH_4	7.2	5.3	2.8	2.5	2.5	2.6	2.5
N_2O	37.8	41.9	18.7	16.0	16.8	16.5	16.2
Electric Power	**1,838.7**	**2,427.8**	**1,626.9**	**1,458.5**	**1,561.3**	**1,552.6**	**1,432.3**
CO_2	1,820.0	2,400.1	1,606.7	1,439.6	1,540.9	1,531.7	1,414.2
CH_4	0.5	1.0	1.4	1.4	1.4	1.5	1.5
N_2O	18.2	26.7	18.8	17.5	19.0	19.4	16.6
Industrial	**881.3**	**852.2**	**813.7**	**767.1**	**784.2**	**803.3**	**796.0**
CO_2	876.5	847.6	809.8	763.4	780.5	799.7	792.6
CH_4	2.1	1.9	1.7	1.6	1.6	1.6	1.5
N_2O	2.8	2.6	2.2	2.0	2.1	2.0	1.9
Residential	**345.4**	**364.2**	**349.1**	**319.0**	**322.3**	**340.2**	**312.2**
CO_2	338.6	358.9	342.9	314.8	318.0	335.2	307.1
CH_4	5.9	4.5	5.3	3.6	3.6	4.3	4.5
N_2O	0.9	0.8	0.8	0.6	0.6	0.7	0.7
Commercial	**229.8**	**228.6**	**253.4**	**230.8**	**239.1**	**260.8**	**245.7**
CO_2	228.3	227.1	251.7	229.3	237.5	259.2	244.2
CH_4	1.2	1.2	1.3	1.2	1.3	1.3	1.3
N_2O	0.3	0.3	0.3	0.3	0.3	0.3	0.3
U.S. Territories[a]	**20.1**	**52.1**	**24.9**	**22.4**	**24.2**	**23.6**	**25.0**
Total	**4,829.2**	**5,830.6**	**4,906.1**	**4,389.3**	**4,704.0**	**4,753.2**	**4,606.5**

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

Other than the greenhouse gases CO_2, CH_4, and N_2O, gases emitted from stationary combustion include the greenhouse gas precursors nitrogen oxides (NO_x), CO, NMVOCs, and sulfur dioxide (SO_2). Methane and N_2O emissions from stationary combustion sources depend upon fuel characteristics and the 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 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.[10] Emissions from U.S. Territories are also calculated separately due to a lack of end-use-specific consumption data.[11] 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 with Electricity Emissions Distributed (MMT CO_2 Eq.)

End-Use Sector	1990	2005	2019	2020	2021	2022	2023
Transportation	**1,517.0**	**1,910.5**	**1,842.4**	**1,594.9**	**1,776.8**	**1,777.2**	**1,800.2**
CO_2	1,472.0	1,863.3	1,820.9	1,576.4	1,757.5	1,758.0	1,781.5
CH_4	7.2	5.3	2.8	2.5	2.5	2.6	2.5
N_2O	37.8	41.9	18.7	16.0	16.8	16.5	16.2
Industrial	**1,574.8**	**1,597.0**	**1,285.1**	**1,182.2**	**1,235.3**	**1,246.5**	**1,205.7**
CO_2	1,562.9	1,584.0	1,275.3	1,173.3	1,225.7	1,236.9	1,197.1
CH_4	2.2	2.2	2.1	2.0	2.0	2.0	1.9
N_2O	9.7	10.8	7.6	7.1	7.6	7.6	6.7

[10] 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.

[11] U.S. Territories (including American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other outlying U.S. Pacific Islands) consumption data 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.

End-Use Sector	1990	2005	2019	2020	2021	2022	2023
Residential	**944.2**	**1,230.1**	**940.7**	**872.1**	**902.9**	**914.4**	**827.3**
CO_2	931.3	1,214.9	927.1	860.7	891.1	901.6	815.6
CH_4	6.0	4.9	5.8	4.2	4.2	4.9	5.0
N_2O	6.9	10.3	7.7	7.3	7.7	7.9	6.7
Commercial	**773.1**	**1,040.9**	**813.1**	**717.5**	**764.6**	**791.5**	**748.2**
CO_2	766.0	1,030.1	804.5	709.7	756.2	782.7	740.3
CH_4	1.3	1.5	1.8	1.7	1.7	1.8	1.8
N_2O	5.7	9.3	6.8	6.2	6.7	7.0	6.1
U.S. Territories[a]	**20.1**	**52.1**	**24.9**	**22.4**	**24.2**	**23.6**	**25.0**
Total	**4,829.2**	**5,830.6**	**4,906.1**	**4,389.3**	**4,704.0**	**4,753.2**	**4,606.5**

[a] U.S. Territories are not apportioned by sector, and emissions are total greenhouse gas emissions from all fuel combustion sources.
Notes: Totals may not sum due to independent rounding. Emissions from fossil fuel combustion by electric power are allocated based on aggregate national electricity use by each end-use sector.

Electric Power Sector

The process of generating electricity is the largest stationary source of CO_2 emissions in the United States, representing 28.8 percent of total CO_2 emissions from all CO_2 emissions sources across the United States and 31.0 percent of CO_2 emissions from fossil fuel combustion in 2023. Methane and N_2O accounted for a small portion of total greenhouse gas emissions from electric power generation, representing 0.1 percent and 1.2 percent, respectively. Methane and N_2O from electric power represented 13.4 and 46.5 percent of total CH_4 and N_2O emissions from fossil fuel combustion in 2023, 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 energy use and emissions associated with the electric power sector are included here. As defined by EIA, 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). Energy use and emissions associated with electric generation in the commercial and industrial sectors is reported in those other sectors where the producer of the power indicates that its primary business is something other than the production of electricity.[12]

Total greenhouse gas emissions from the electric power sector have decreased by 22.1 percent since 1990. From 1990 to 2007, electric power sector emissions increased by 33 percent, driven by a significant increase in electricity demand (39 percent) while the carbon intensity of electricity generated showed a modest decline (2.1 percent). From 2008 to 2023, as electricity demand increased by 3.8 percent, electric power sector emissions decreased by 40 percent, driven by a significant drop (29 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 31 percent from 1990 to 2023 with additional trends detailed in Box 3-4. This trend is shown in Figure 3-7. This recent decarbonization of the electric power sector is a result of several key drivers.

[12] 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.

Coal-fired electric generation (in kilowatt-hours [kWh]) decreased from 54 percent of generation in 1990 to 17 percent in 2023.[13] 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 34-year period to represent 42 percent of electric power sector generation in 2023 (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 United States in 2023 had an average carbon content of 14.43 MMT C/Qbtu and 26.15 MMT C/Qbtu respectively.

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

Fuel Type	1990	2005	2019	2020	2021	2022	2023
Coal	54.1%	51.1%	24.2%	19.9%	22.6%	20.3%	16.6%
Natural Gas	10.7%	17.5%	37.3%	39.5%	37.3%	38.8%	42.2%
Nuclear	19.9%	20.0%	20.4%	20.5%	19.7%	18.9%	19.2%
Renewables	11.3%	8.3%	17.6%	19.5%	19.8%	21.4%	21.5%
Petroleum	4.1%	3.0%	0.4%	0.4%	0.5%	0.5%	0.4%
Other Gases[a]	+%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Net Electricity Generation (Billion kWh)[b]	2,905	3,902	3,966	3,851	3,955	4,076	4,031

+ 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 2023, CO_2 emissions from the electric power sector decreased by 7.7 percent relative to 2022. This decrease in CO_2 emissions was primarily driven by a decrease in coal consumed to produce electricity in the electric power sector. Consumption of coal for electric power decreased by 18.4 percent while consumption of natural gas increased 6.9 percent from 2022 to 2023, leading to an overall decrease in emissions. There has also been a rapid increase in renewable electricity generation in the electric power sector in recent years and electricity generation from renewable sources remained relatively flat from 2022 to 2023 (see Table 3-12). A decrease in coal-fired electricity generation and increases in natural gas and renewable energy sources for electricity generation contributed to a decoupling of emissions trends from electric power generation trends starting around 2005 (EIA 2024g) (see Figure 3-7).

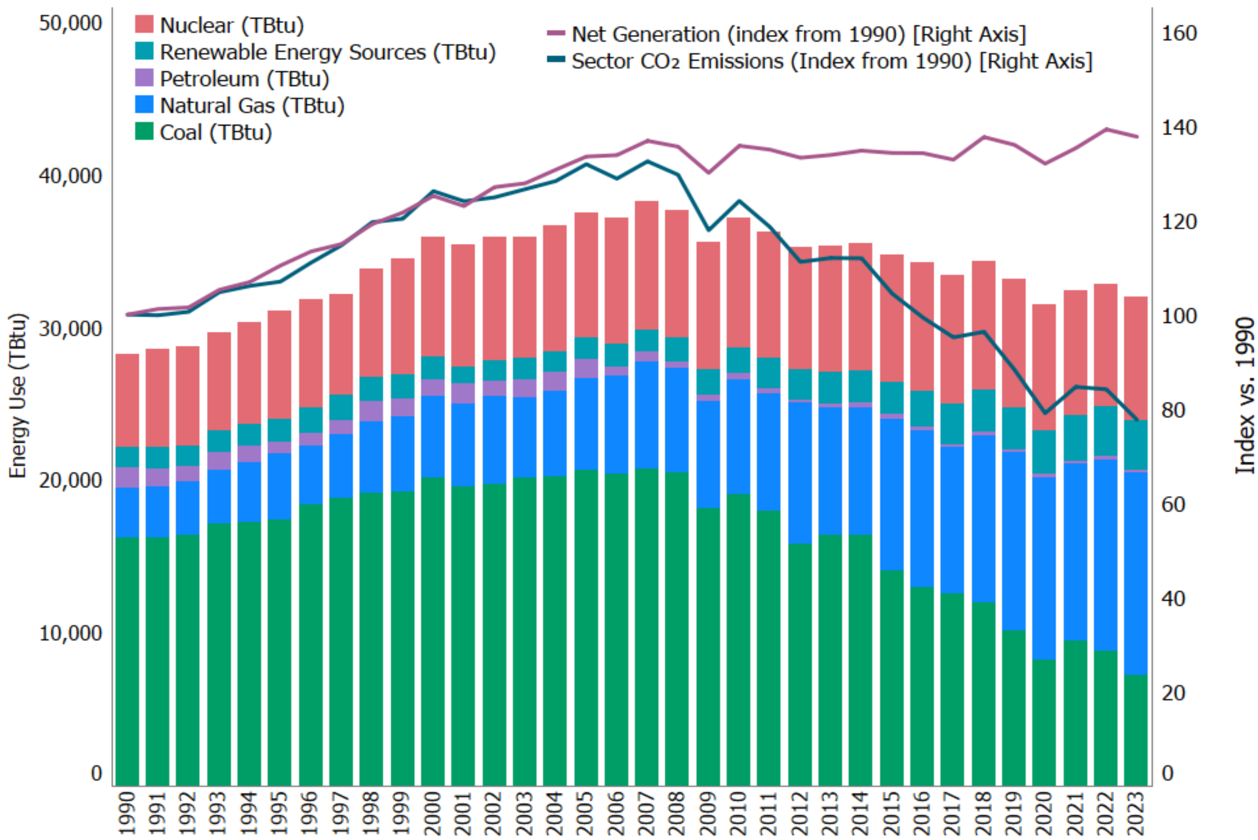
The shift from coal to natural gas comes from a variety of factors including the increase in natural gas generation, particularly between 2005 and 2020 and the relative prices of using coal vs. natural gas for electricity generation (EIA 2022a; EIA 2022b). The aging coal fleet and coal plant retirements also contributes to why this trend is continuing (EIA 2025b). From 2022 to 2023, coal consumption decreased by 18 percent while natural gas consumption increased by 7 percent.

Also, in 2023 the Petra Nova project sequestered 359,840 metric tons of CO_2 from a coal fired power plant. These emissions have been netted out of the results shown in this chapter for electric power sector coal CO_2 emissions. More information on CO_2 transport, injection, and geologic sequestration can be found in Section 3.9.

[13] Values represent electricity *net* generation from the electric power sector (EIA 2024a).

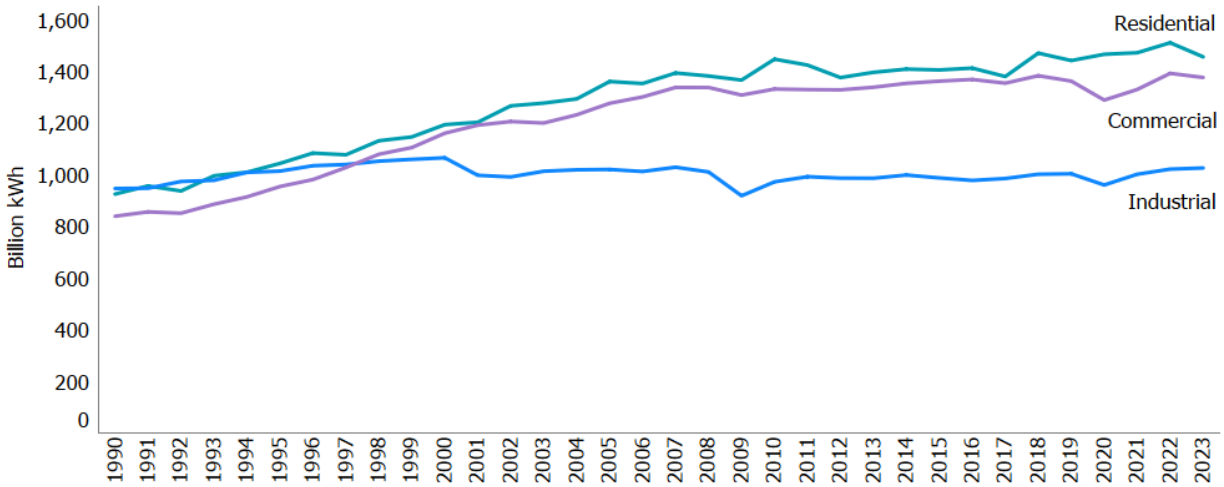
Renewable energy generation (in kWh) from wind and solar energy increased from 0.1 percent of total generation in 1990 to 5 percent in 2015 and increased at a faster pace to 15 percent of total generation in 2023. The decrease in carbon intensity occurred even as total electricity retail sales increased 43 percent, from 2,713 billion kWh in 1990 to 3,874 billion kWh in 2023.

Figure 3-7: 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 3-8). Note that transportation is an end-use sector as well but is not shown in Figure 3-8 due to the sector's relatively low percentage of electricity use. The Transportation Sector and Mobile Combustion section provides a break-out of CO_2 emissions from electricity use in the transportation end-use sector.

Figure 3-8: Electric Power Retail Sales by End-Use Sector



In 2023, electricity sales to the residential and commercial end-use sectors, as presented in Figure 3-8, decreased by 3.9 percent and increased 1.2 percent relative to 2022, respectively. Electricity sales to the industrial sector in 2023 decreased by approximately 1.1 percent relative to 2022. The sections below describe end-use sector energy use in more detail. Overall, in 2023, the amount of electricity retail sales (in kWh) decreased by 1.3 percent relative to 2022.

Industrial Sector

Industrial sector CO_2, CH_4, and N_2O emissions accounted for 17, 13, and 5 percent of CO_2, CH_4, and N_2O emissions from fossil fuel combustion, respectively, in 2023. 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 2025a; 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.[14] 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 2022 to 2023, total industrial production and manufacturing output increased by 0.2 percent (FRB 2023). Over this period, output increased slightly across production indices for Food, Nonmetallic Mineral Products, and Paper. Production of chemicals, petroleum refineries, and primary metals declined slightly between 2022 and 2023 (see Figure 3-9). From 2022 to 2023, total energy use in the

[14] 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.

industrial sector decreased by 0.9 percent, driven mainly by a 15.3 percent decrease in coal consumption in the industrial sector. Consumption of renewables decreased 3.0 percent from 2022 to 2023. Due to the relative increases and decreases of individual indices there was an increase in natural gas and a decrease in electricity used by this sector (see Figure 3-10). In 2023, CO_2, CH_4, and N_2O emissions from fossil fuel combustion and electricity use within the industrial end-use sector totaled 1,205.7 MMT CO_2 Eq., a 3.3 percent decrease from 2022 emissions.

Through EPA's Greenhouse Gas Reporting Program (GHGRP), specific industrial sector trends can be discerned from the overall total EIA industrial fuel consumption data used for these calculations. For example, from 2022 to 2023, the underlying EIA data showed increased consumption of natural gas, decreased consumption of petroleum, and decreased consumption of coal 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.[15]

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

Figure 3-9: Industrial Production Indices (Index 2017=100)

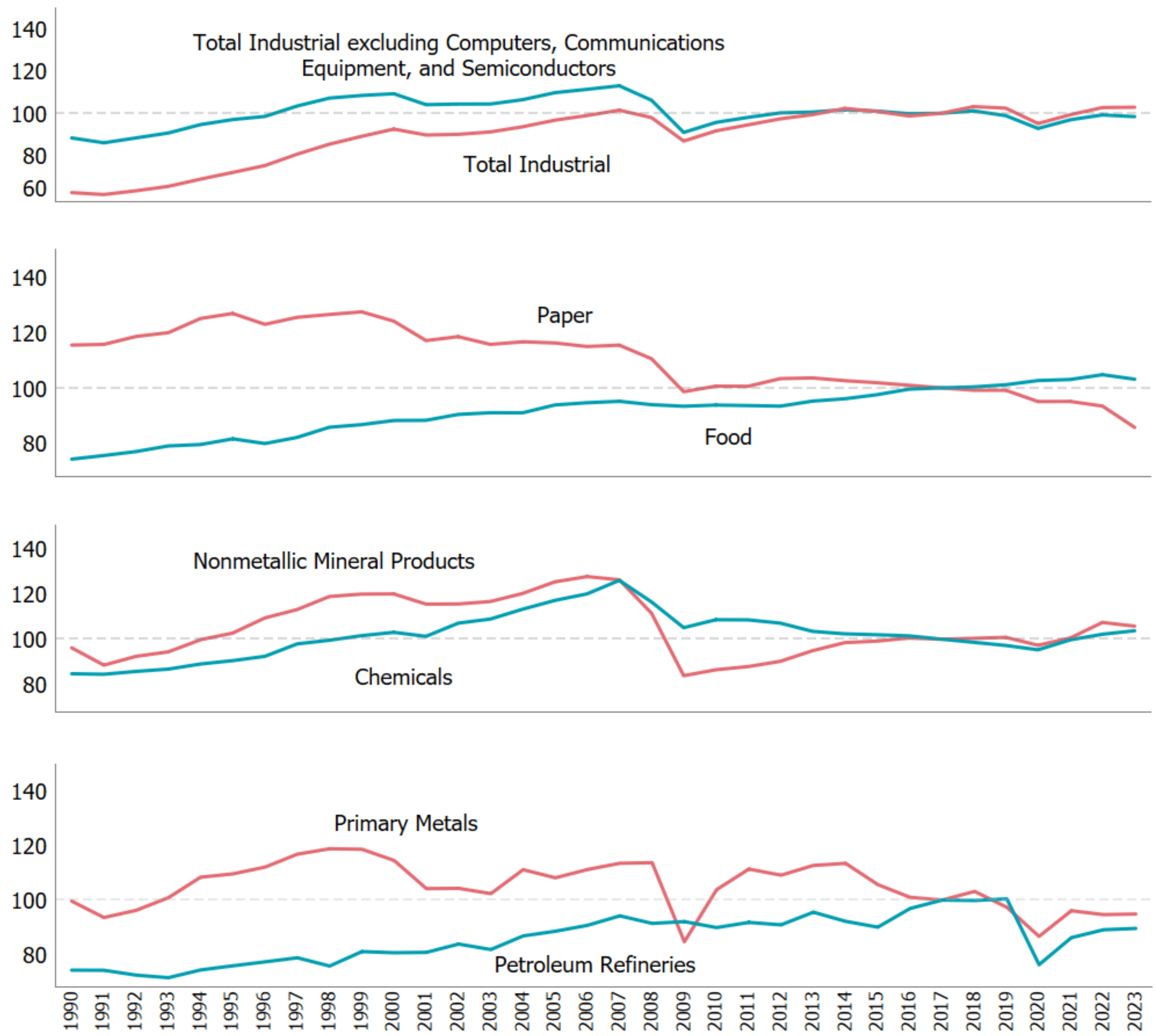
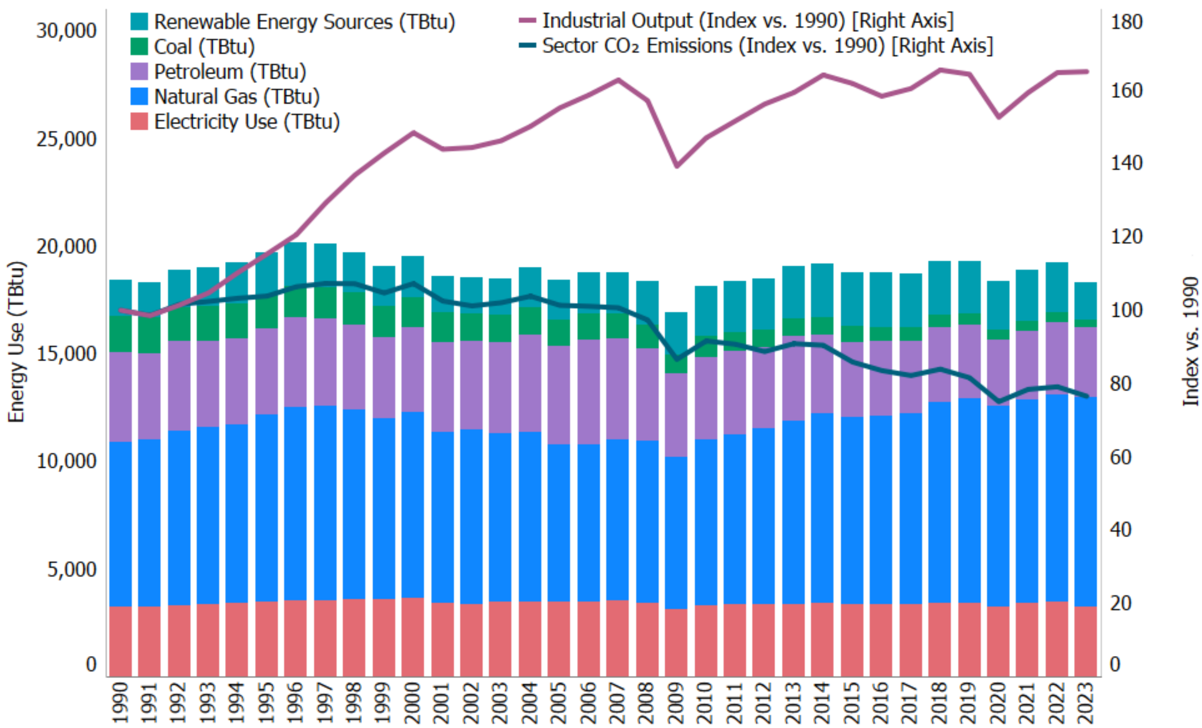


Figure 3-10: Fuels and Electricity Used in Industrial Sector, Industrial Output, and Total Sector CO_2 Emissions (Including Electricity)



Despite the growth in industrial output (65 percent) and the overall U.S. economy (125 percent) from 1990 to 2023, direct CO_2 emissions from fossil fuel combustion in the industrial sector decreased by 9.6 percent over the same time series. A number of factors are assumed to result in decoupling of growth in industrial output from industrial greenhouse gas emissions, for example: (1) more rapid growth in output from less energy-intensive industries relative to traditional manufacturing industries, and (2) energy-intensive industries such as steel are employing new methods, such as electric arc furnaces, that are less carbon-intensive than the older methods.

Box 3-2: 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 2023 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 for national inventory reporting. The IPCC has provided guidance on aligning facility-level reported fuels and fuel types published in national energy statistics, which guided this exercise.[16]

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. Progress was made on certain fuel types for specific industries and has been included in common data tables.[17] 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 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. 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 2023 time period. 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

Total direct and indirect emissions from the residential and commercial sectors have generally decreased since 2005. This is due in part to reduced electricity sector emissions intensity which results in decreased indirect emissions from electricity use. For example, starting around 2014, total energy use and emissions begin to decouple due to decarbonization of the electric power sector (see Figure 3-11). Short-term trends in the residential and commercial sectors 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 countered the increase in energy use in recent years. The 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 2023b; Nadel, et al. 2015), resulting in a decrease in energy-related emissions in the residential sector since 1990.

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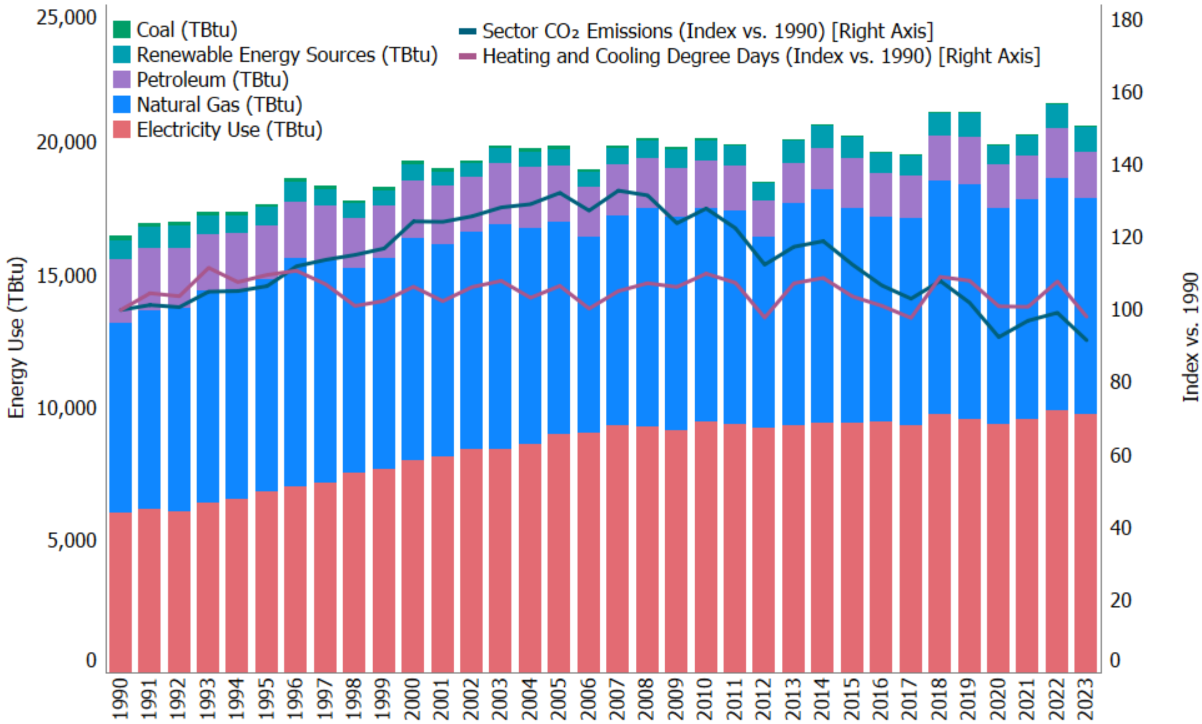
[16] See Section 4 "Use of Facility-Level Data in Good Practice National Greenhouse Gas Inventories" of the IPCC meeting report, and specifically the section on using facility-level data in conjunction with energy data, at http://www.ipcc-nggip.iges.or.jp/public/tb/TFI_Technical_Bulletin_1.pdf.

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

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



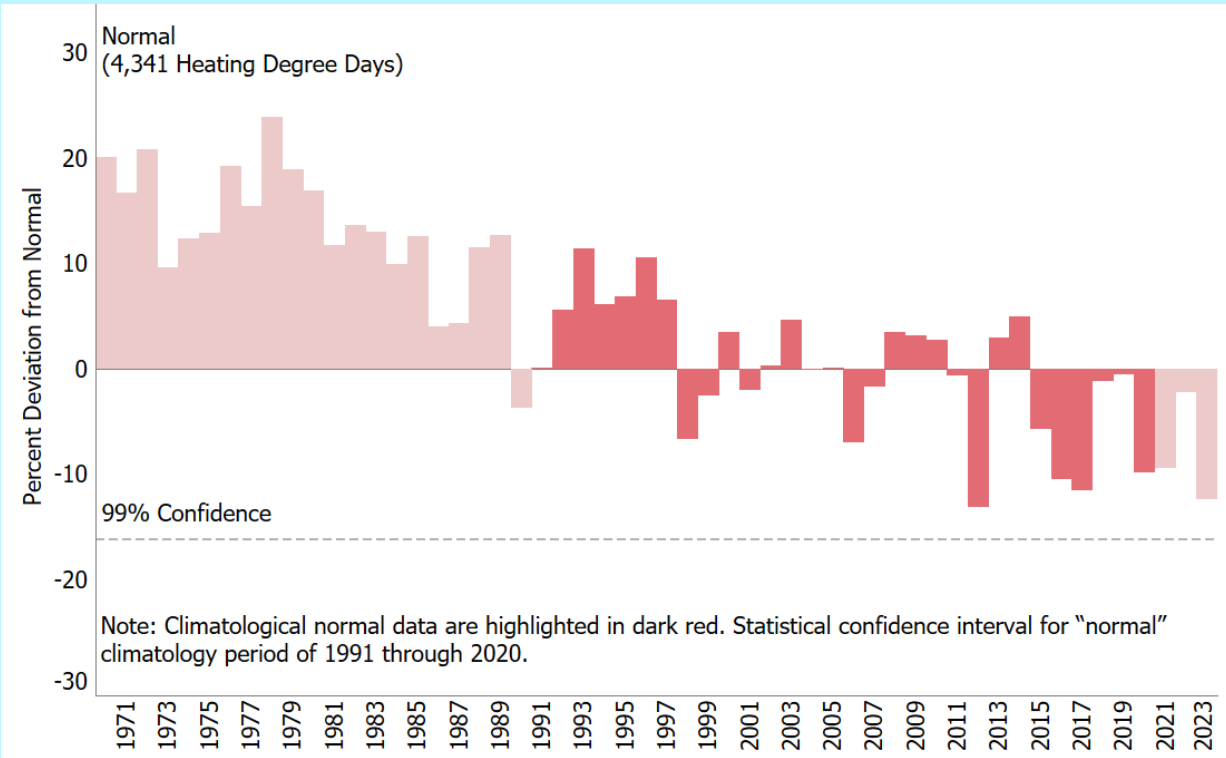
In 2023, excluding indirect emissions from electricity use, the residential and commercial sectors accounted for 7 and 5 percent of CO_2 emissions from fossil fuel combustion, respectively; 40 and 11 percent of CH_4 emissions from fossil fuel combustion, respectively; and 2 and 1 percent of N_2O emissions from fossil fuel combustion, respectively. Emissions from these sectors are primarily attributable to building-related activities such as the direct consumption of natural gas and petroleum products, primarily for heating and cooking needs. Coal consumption was a minor component of energy use in the commercial sector and did not contribute to any energy use in the residential sector. Greenhouse gas emissions from commercial and residential buildings also increase substantially when emissions from electricity end-use are included, because the building sector uses 75 percent of the electricity generated in the United States (e.g., for heating, ventilation, and air conditioning; lighting; and appliances) (NREL 2023). In 2023, 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 827.3 MMT CO_2 Eq. and 748.2 MMT CO_2 Eq., respectively. Direct CO_2, CH_4, and N_2O emissions from fossil fuel combustion within the residential and commercial end-use sectors decreased by 9.5 and 5.5 percent from 2022 to 2023, respectively. This is mainly due to a decrease in heating degree days (10.4 percent) and cooling degree days (5.2 percent) from 2022 to 2023 which decreased energy demand for heating and cooling in the residential and commercial sectors. From 2022 to 2023 there was an 8.5 and a 5.6 percent decrease in direct energy use in the residential and commercial sectors respectively.

In 2023, combustion emissions from natural gas consumption represented 81 and 75 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 2023 decreased by 9.0 percent and 5.0 percent from 2022, respectively.

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

The United States in 2023 experienced a warmer winter overall compared to 2022, with a 10.4 percent decrease in heating degree days, and 2023 heating degree days were 12.4 percent below normal[18] (see Figure 3-12). Along with a warmer winter, 2023 experienced a cooler summer than 2022, with cooling degree days 5.2 percent below 2022. However, cooling degree days were still 10.7 percent above normal (see Figure 3-13) (EIA 2025a).[19] Warmer summers can lead to increased energy use and associated emissions to cool building spaces in the residential and commercial sectors, mostly from electricity use. Whereas, warmer winter conditions can lead to an overall decrease in mainly direct energy use and emissions from fossil fuel combustion in the residential and commercial sectors.

Figure 3-12: Annual Deviations from Normal Heating Degree Days for the United States (1970–2023, Index Normal = 100)



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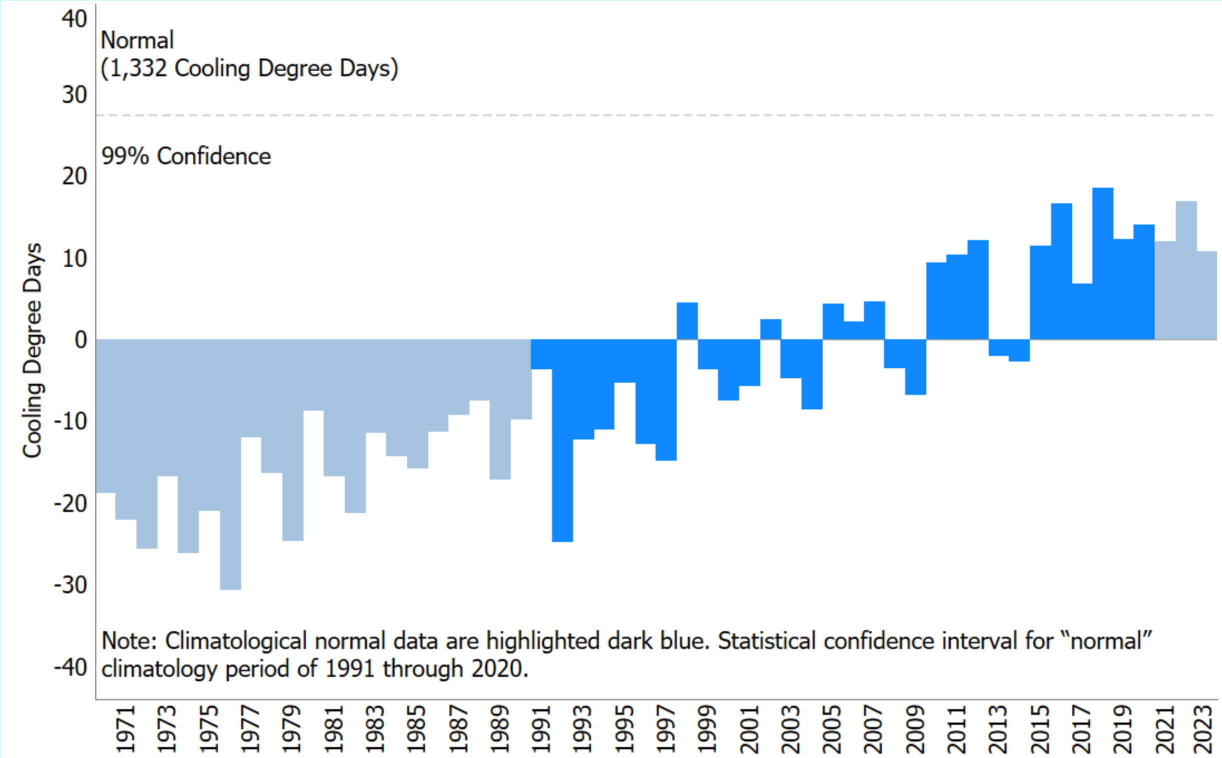
18 The National Centers for Environmental Information of NOAA generates official U.S. climate normals every 10 years in keeping with the needs of the user community and the requirements of the World Meteorological Organization (WMO) and National Weather Service (NWS). The 1991–2020 U.S. Climate Normals are the latest in a series of decadal normals first produced in the 1950s. See https://www.ncei.noaa.gov/products/land-based-station/us-climate-normals. The variation in these normals during this time period was ±16 percent and ±27 percent for heating and cooling degree days, respectively (99 percent confidence interval).

19 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 direct energy demand and related emissions than do cooling degree days. Excludes Alaska and Hawaii.

Figure 3-13: Annual Deviations from Normal Cooling Degree Days for the United States (1970–2023, Index Normal = 100)



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 outlying 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 1-9. Table 1-8 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 1,800.2 MMT CO_2 Eq. in 2023, which represented 39 percent of CO_2 emissions from fossil fuel combustion, 23 percent of CH_4

emissions from fossil fuel combustion, and 46 percent of N_2O emissions from fossil fuel combustion.[20] Fuel purchased in the U.S. for international aircraft and marine travel accounted for an additional 97.0 MMT CO_2 Eq. in 2023; these emissions are recorded as international bunkers and are not included in U.S. totals in line with IPCC guidelines.

Transportation End-Use Sector

From 1990 to 2019, transportation emissions from fossil fuel combustion rose by 21 percent, followed by a reduction of 13 percent from 2019 to 2020, and an increase of 13 percent from 2020 to 2023. Overall, from 1990 to 2023, transportation emissions from fossil fuel combustion increased by 19 percent. The increase in transportation emissions from fossil fuel combustion from 1990 to 2023 was due, in large part, to increased demand for travel (see Figure 3-14). The number of vehicle miles traveled by light-duty motor vehicles (passenger cars and light-duty trucks) increased 49 percent from 1990 to 2023, as a result of a confluence of factors including population growth, economic growth, urban sprawl, and relatively low fuel prices over much of this period. Between 2019 and 2020, emissions from light-duty vehicles fell by 12 percent, primarily the result of the COVID-19 pandemic and associated restrictions, such as people working from home and traveling less.

Commercial aircraft emissions decreased by 5 percent between 2019 and 2023 and have decreased 7 percent since 2007 (FAA 2022 and DOT 1991 through 2025).[21] Decreases in jet fuel emissions (excluding bunkers) started in 2007, 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; however, the sharp decline in commercial aircraft emissions from 2019 to 2020 and their gradual recovery since is primarily due to COVID-19 impacts on scheduled passenger air travel.

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 21 percent from 1990 to 2023. Annex 3.2 presents the total emissions from all transportation and mobile sources, including CO_2, N_2O, CH_4, and HFCs.

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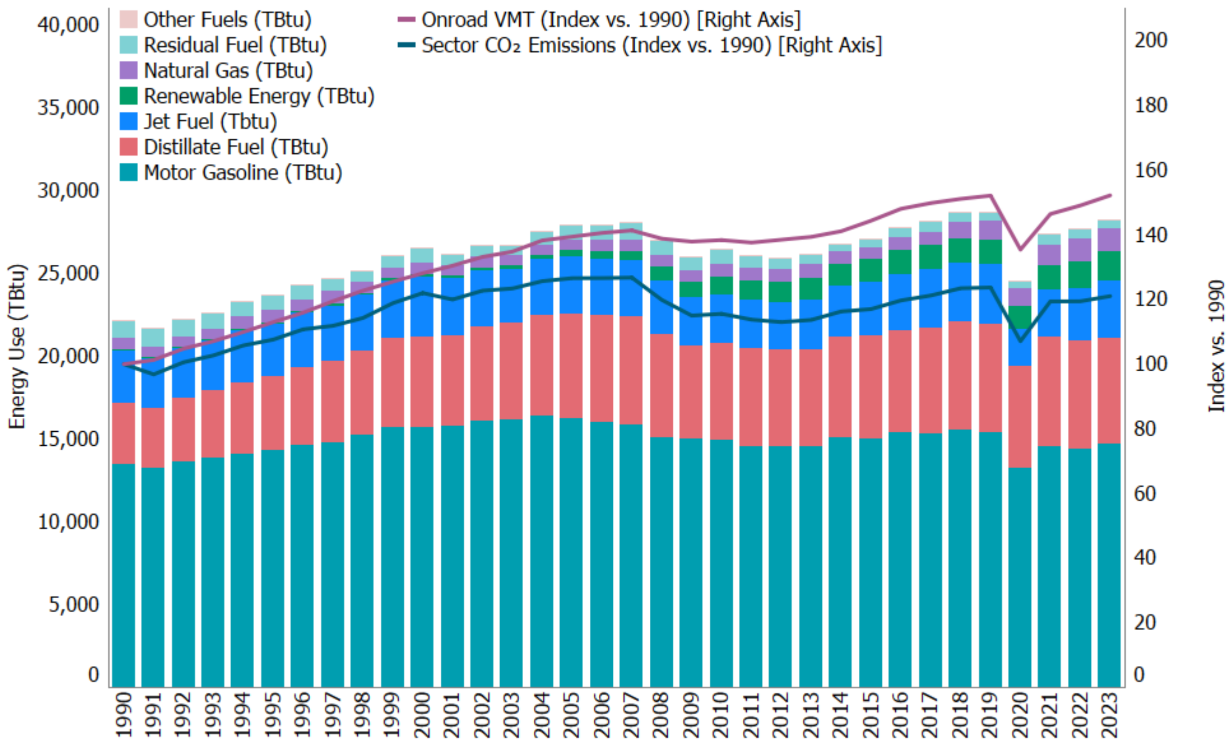
[20] Note that these totals include CO_2, CH_4 and N_2O emissions from some sources in the U.S. Territories (ships and boats, recreational boats, non-transportation mobile sources) and CH_4 and N_2O emissions from transportation rail electricity.

[21] Commercial aircraft consists of passenger aircraft, cargo, and other chartered flights.

Figure 3-14: Fuels Used in Transportation Sector, On-road 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 (2024).

Transportation Fossil Fuel Combustion CO_2 Emissions

Domestic transportation CO_2 emissions increased by 21 percent (309.5 MMT CO_2 Eq.) between 1990 and 2023, an annualized increase of 0.6 percent. This includes a 24 percent increase in CO_2 emissions between 1990 and 2019, followed by a 13 percent decrease from 2019 to 2020. Carbon dioxide emissions then increased by 13 percent between 2020 and 2023. Among domestic transportation sources, light-duty vehicles (including passenger cars and light-duty trucks) represented 57 percent of CO_2 emissions, medium- and heavy-duty trucks and buses 25 percent, commercial aircraft 7 percent, and other sources 11 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.[22] Ethanol consumption from the transportation sector has increased from 0.7 billion gallons in 1990 to

[22] Biofuel estimates are presented in the Energy chapter for informational purposes only, in line with IPCC methodological guidance. 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.

13.2 billion gallons in 2023, while biodiesel consumption has increased from 0.01 billion gallons in 2001 to 1.6 billion gallons in 2023. For additional information, see Section 3.11 on biofuel consumption at the end of this chapter and Table A-71 in Annex 3.2.

Carbon dioxide emissions from passenger cars and light-duty trucks totaled 1,007.9 MMT CO_2 in 2023, an increase of 10 percent (95.2 MMT CO_2) from 1990. The increase in CO_2 emissions from passenger cars and light-duty trucks from 1990 to 2023 was 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 2023). Carbon dioxide emissions from passenger cars and light-duty trucks peaked at 1,146.3 MMT in 2004, and since then have declined about 12 percent. The decline in new light-duty vehicle fuel economy between 1990 and 2004 (see 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, and again between 2017 and 2019. VMT grew at faster rates of 2.3 percent from 2014 to 2015, and 1.7 percent from 2015 to 2016. From 2019 to 2020, light-duty vehicle VMT declined by 12.0 percent due to COVID-19 pandemic; from 2020 to 2023 light-duty vehicle VMT rebounded as a part of the ongoing recovery from the pandemic, increasing by 12.2 percent.

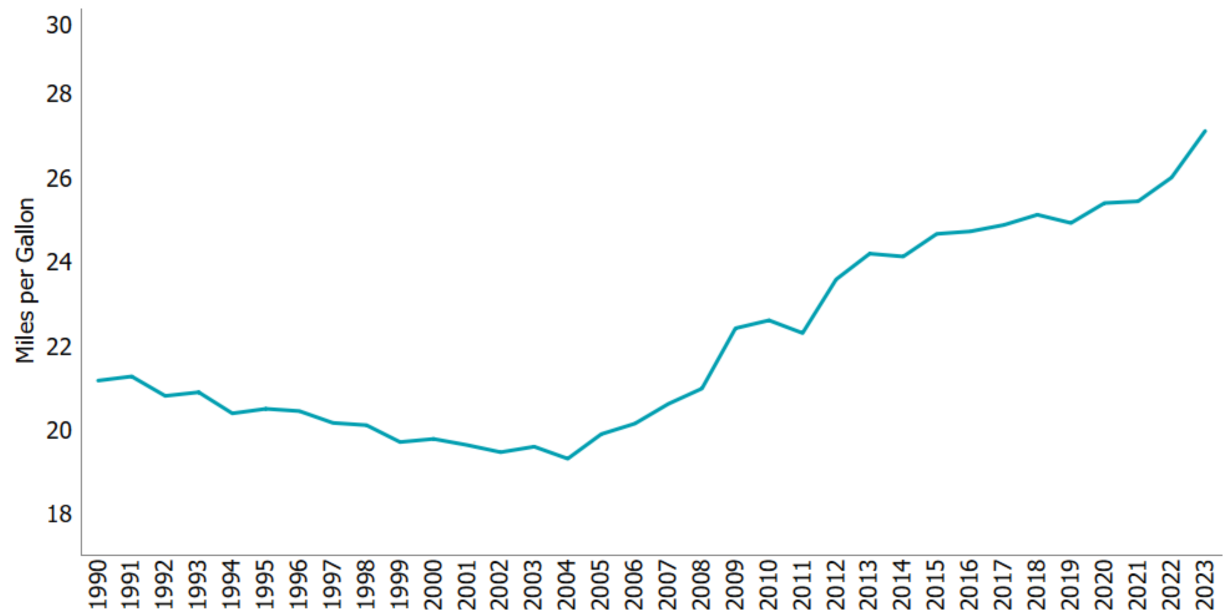
Average new vehicle fuel economy has improved almost every year since 2005 while the light-duty truck share of new vehicle sales decreased to about 33 percent of new vehicles in 2009 and has since varied from year to year between 36 and 63 percent. Since 2014, the light-duty truck share has steadily increased, reaching 62 percent of new vehicle sales in model year 2023. 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 78 percent from 1990 to 2023. This increase was largely due to a substantial growth in medium- and heavy-duty truck VMT, which increased by 84 percent between 1990 and 2023.

Carbon dioxide from the domestic operation of commercial aircraft increased by 18 percent (19.8 MMT CO_2) from 1990 to 2023. Across all categories of aviation, excluding international bunkers, CO_2 emissions decreased by 4 percent (6.9 MMT CO_2) between 1990 and 2023.[23] Carbon dioxide emissions from military aircraft decreased 68 percent between 1990 and 2023. Commercial aircraft CO_2 emissions increased 27 percent between 1990 and 2007, dropped 2 percent from 2007 to 2019, dropped another 33 percent from 2019 to 2020, then increased by 30 percent from 2020 to 2023. Overall, this represents a change of approximately 18 percent between 1990 and 2023. Transportation sources also produce CH_4 and N_2O; these emissions are included in Figure 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.

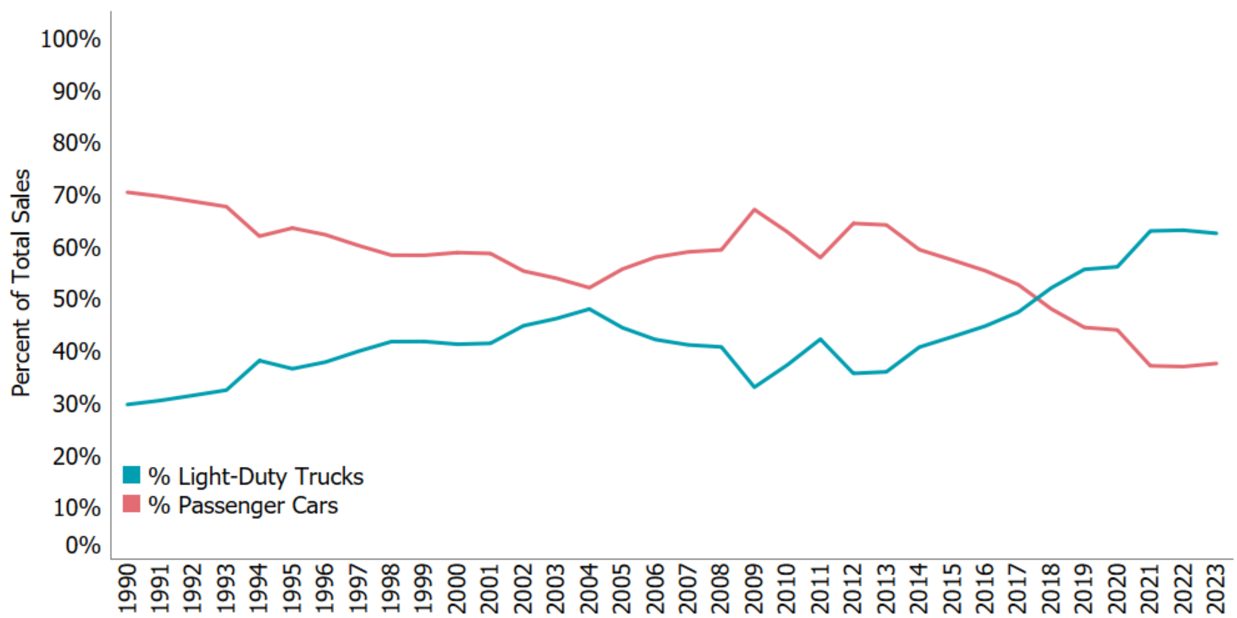
[23] Includes consumption of jet fuel and aviation gasoline. Does not include aircraft bunkers, which are not included in national emission totals, in line with IPCC methodological guidance.

Figure 3-15: Sales-Weighted Fuel Economy of New Passenger Cars and Light-Duty Trucks, 1990–2023



Source: EPA (2023).

Figure 3-16: Sales of New Passenger Cars and Light-Duty Trucks, 1990–2023



Source: EPA (2023).

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

Fuel/Vehicle Type	1990	2005	2019	2020	2021	2022	2023
Gasoline[a]	**958.9**	**1,150.1**	**1,086.5**	**936.9**	**1,028.7**	**1,014.5**	**1,035.7**
Passenger Cars	622.7	525.0	358.8	297.8	314.1	296.6	293.6
Light-Duty Trucks	271.7	576.1	675.2	590.5	658.9	659.2	682.4
Medium- and Heavy-Duty Trucks[b]	41.8	28.8	31.5	29.5	34.7	35.8	36.3
Buses	5.1	1.8	3.6	3.1	3.5	3.9	4.1
Motorcycles	3.3	4.7	6.7	6.1	6.9	8.2	8.6
Recreational Boats[c]	14.3	13.7	10.7	9.9	10.6	10.8	10.8
Distillate Fuel Oil (Diesel)[a]	**262.9**	**462.6**	**474.0**	**447.4**	**480.6**	**476.7**	**471.3**
Passenger Cars	9.9	4.1	2.5	2.0	2.0	1.9	1.8
Light-Duty Trucks	8.2	30.1	32.0	26.4	27.8	27.9	27.5
Medium- and Heavy-Duty Trucks[b]	192.0	356.2	373.0	361.3	389.8	384.2	381.2
Buses	7.8	14.9	20.2	16.3	17.9	19.5	19.3
Rail	35.5	46.1	36.0	31.2	32.5	32.5	30.9
Recreational Boats[c]	2.7	2.9	2.9	2.6	2.8	3.0	2.9
Ships and Non-Recreational Boats[d]	6.8	8.4	7.5	7.6	7.8	7.8	7.7
International Bunker Fuels[e]	*11.7*	*9.5*	*10.1*	*7.8*	*7.4*	*7.2*	*7.0*
Jet Fuel	**184.1**	**189.2**	**180.3**	**120.6**	**152.6**	**164.8**	**178.9**
Commercial Aircraft[f]	109.9	132.7	136.7	91.3	119	129.7	129.7
Military Aircraft	35.7	19.8	12.2	11.7	12.5	12.4	11.5
General Aviation Aircraft	38.5	36.8	31.4	17.6	21.1	22.7	37.7
International Bunker Fuels[e]	*38.2*	*60.2*	*78.3*	*39.8*	*50.8*	*66.6*	66.5
International Bunker Fuels from Commercial Aviation	*30.0*	*55.6*	*75.1*	*36.7*	*47.6*	*63.5*	*63.5*
Aviation Gasoline	**3.1**	**2.4**	**1.6**	**1.4**	**1.5**	**1.5**	**1.5**
General Aviation Aircraft	3.1	2.4	1.6	1.4	1.5	1.5	1.5
Residual Fuel Oil	**22.6**	**19.3**	**14.5**	**7.3**	**24.2**	**22.9**	**16.6**
Ships and Non-Recreational Boats[e]	22.6	19.3	14.5	7.3	24.2	22.9	16.6
International Bunker Fuels[e]	*53.7*	*43.6*	*25.2*	*22.1*	*21.9*	*24.4*	*22.7*
Natural Gas[g]	**36.0**	**33.1**	**58.9**	**58.8**	**65.2**	**72.3**	**71.7**
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+
Medium- and Heavy-Duty Trucks	+	+	0.1	0.1	0.1	0.1	0.1
Buses	+	0.2	0.3	0.2	0.2	0.3	0.3
Pipeline[h]	36.0	32.8	58.5	58.5	64.9	72.0	71.3
LPG[g]	**1.4**	**1.8**	**0.8**	**0.5**	**0.6**	**0.7**	**0.7**
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	0.1	0.1	+	+	+	0.1	0.1
Medium- and Heavy-Duty Trucks[b]	1.3	0.9	0.7	0.5	0.5	0.5	0.5
Buses	+	0.7	0.1	0.1	0.1	0.1	0.1
Electricity[i]	**3.0**	**4.7**	**4.2**	**3.5**	**4.0**	**4.5**	**5.0**
Passenger Cars	+	+	0.1	0.1	0.2	0.4	0.7
Light-Duty Trucks	+	+	1.1	1.0	1.3	1.6	1.9

Fuel/Vehicle Type	1990	2005	2019	2020	2021	2022	2023
Buses	+	+	+	+	+	+	+
Rail	3.0	4.7	3.1	2.4	2.5	2.5	2.4
Total [e,j]	**1,472.0**	**1,863.3**	**1,820.9**	**1,576.4**	**1,757.5**	**1,758.0**	**1,781.5**
International Bunker Fuels	*103.6*	*113.3*	*113.6*	*69.6*	*80.2*	*98.2*	*96.2*
Biofuels-Ethanol[k]	*4.1*	*21.6*	*78.7*	*68.1*	*75.4*	*75.0*	*76.4*
Biofuels-Biodiesel[k]	*0.0*	*0.9*	*17.1*	*17.7*	*16.1*	*15.6*	*18.2*

+ Does not exceed 0.05 MMT CO_2 Eq.

[a] On-road fuel consumption data from FHWA Table MF-21 and MF-27 were used to determine total on-road use of motor gasoline and diesel fuel (FHWA 1996 through 2024). Ratios developed from MOVES5 output are used to apportion FHWA fuel consumption data to vehicle type and fuel type (see Annex 3.2 for information about the MOVES model). Onroad vehicle VMT and fuel consumption are proxied based on the Traffic Volume Trends data for the year 2023.

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

[c] In 2014, EPA incorporated the NONROAD2008 model into the MOVES model framework. The current Inventory uses the Nonroad component of MOVES5 for years 1999 through 2023. See Annex 3.2 for information about the MOVES model.

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

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

[f] Commercial aircraft, as modeled in FAA's Aviation Environmental Design Tool (AEDT), consists of passenger aircraft, cargo, and other chartered flights.

[g] Transportation sector natural gas and LPG consumption are based on data from EIA (24). 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 2023 time period.

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

[i] 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). The mileage accumulation rates for electric vehicles were lowered this year based on research by Browning (2024). In prior Inventory years, CO_2 emissions from electric vehicle charging were allocated to the residential and commercial sectors. They are allocated to the transportation sector. These changes apply to the 2010 through 2023 time period.

[j] Includes emissions from rail electricity.

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

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

Mobile Fossil Fuel Combustion CH_4 and N_2O Emissions

Mobile combustion includes emissions of CH_4 and N_2O from all transportation sources identified in the U.S. *Inventory* with the exception of pipelines and electric locomotives;[24] 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.).[25] Annex 3.2 includes a

[24] 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.

[25] 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 mobile sources (e.g., lawn and garden equipment, farm equipment, construction equipment) are allocated to their respective

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.[26]

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 (4.2 percent) in 2023. From 1990 to 2023, mobile source CH_4 emissions declined by 64.9 percent, to 2.5 MMT CO_2 Eq. (91 kt), due largely to emissions control technologies employed in on-road vehicles since the mid-1990s to reduce CO, NOx, NMVOC, and CH_4 emissions. Mobile source emissions of N_2O decreased by 57.0 percent, to 16.2 MMT CO_2 Eq. (61 kt) in 2023. Earlier generation control technologies initially resulted in elevated N_2O emissions, causing a 32 percent increase in N_2O emissions from mobile sources between 1990 and 1997. Improvements in later-generation emission control technologies have reduced N_2O output, resulting in a 67 percent decrease in mobile source N_2O emissions from 1997 to 2023 (see Figure 3-17). Overall, CH_4 and N_2O emissions were predominantly from gasoline-fueled passenger cars, 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.

Figure 3-17: Mobile Source CH_4 and N_2O Emissions

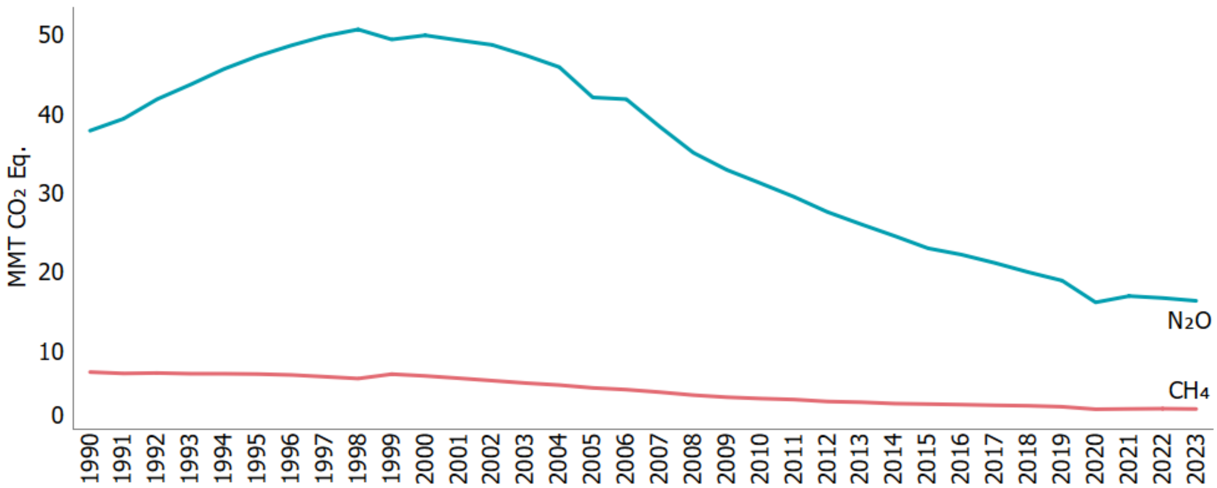


Table 3-14: CH_4 Emissions from Mobile Combustion (MMT CO_2 Eq.)

Fuel Type/Vehicle Type[a]	1990	2005	2019	2020	2021	2022	2023
Gasoline On-Road[b]	**5.8**	**3.3**	**1.0**	**0.8**	**0.8**	**0.8**	**0.7**
Passenger Cars	3.8	1.8	0.3	0.2	0.2	0.2	0.2
Light-Duty Trucks	1.4	1.3	0.6	0.5	0.5	0.5	0.5
Medium- and Heavy-Duty Trucks and Buses	0.5	0.2	+	+	+	+	+
Motorcycles	+	+	+	+	+	+	+
Diesel On-Road[b]	**+**	**+**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**

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.

[26] See Annex 3.2 for a complete time series of emission estimates for 1990 through 2023.

Fuel Type/Vehicle Type[a]	1990	2005	2019	2020	2021	2022	2023
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+
Medium- and Heavy-Duty Trucks	+	+	0.1	0.1	0.1	0.1	0.1
Medium- and Heavy-Duty Buses	+	+	+	+	+	+	+
Alternative Fuel On-Road	**+**	**+**	**+**	**+**	**+**	**+**	**+**
Non-Road[c]	**1.4**	**1.8**	**1.7**	**1.6**	**1.6**	**1.7**	**1.7**
Ships and Boats	0.4	0.5	0.4	0.4	0.5	0.5	0.5
Rail[d]	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Aircraft	0.1	0.1	+	+	+	+	+
Agricultural Equipment[e]	0.2	0.2	0.1	0.1	0.1	0.1	0.1
Construction/Mining Equipment[f]	0.2	0.3	0.2	0.2	0.2	0.2	0.2
Other[g]	0.5	0.7	0.8	0.8	0.7	0.8	0.8
Total	**7.2**	**5.2**	**2.8**	**2.5**	**2.6**	**2.6**	**2.5**

+ 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. VMT for 2023 is based on FHWA's Traffic Volume Trends data series. VMT estimates from FHWA are allocated to vehicle type using ratios of VMT per vehicle type to total VMT, derived from EPA's MOVES5 model (see Annex 3.2 for information about the MOVES model).
[c] Nonroad fuel consumption estimates for 2020 are adjusted to account for the COVID-19 pandemic and associated restrictions. For agricultural equipment and airport equipment, sector specific adjustment factors were applied to the 2019 data. For all other sectors, a 7.7 percent reduction factor is used, based on transportation diesel use (EIA 2025a).
[d] Rail emissions do not include emissions from electric powered locomotives. Class II and Class III diesel consumption data for 2014 to 2023 is estimated by applying the historical average fuel usage per carload factor to the annual number of carloads.
[e] Includes equipment, such as tractors and combines, as well as fuel consumption from trucks that are used off-road in agriculture.
[f] Includes equipment, such as cranes, dumpers, and excavators, as well as fuel consumption from trucks that are used off-road in construction.
[g] "Other" includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment, as well as fuel consumption from trucks that are used off-road for commercial/industrial purposes.
Note: Totals may not sum due to independent rounding.

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

Fuel Type/Vehicle Type[a]	1990	2005	2019	2020	2021	2022	2023
Gasoline On-Road[b]	**31.4**	**33.4**	**8.2**	**6.3**	**6.1**	**5.4**	**4.8**
Passenger Cars	22.3	16.4	2.6	2.0	1.8	1.5	1.4
Light-Duty Trucks	8.2	15.8	5.3	4.1	4.0	3.6	3.2
Medium- and Heavy-Duty Trucks and Buses	0.9	1.2	0.2	0.2	0.2	0.1	0.1
Motorcycles	+	+	0.1	0.1	0.1	0.1	0.1
Diesel On-Road[b]	**0.42**	**0.4**	**2.9**	**2.9**	**3.3**	**3.4**	**3.5**
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	0.2	0.2	0.2	0.2	0.2
Medium- and Heavy-Duty Trucks	0.2	0.3	2.4	2.5	2.9	2.9	3.0
Medium- and Heavy-Duty Buses	+	+	0.2	0.2	0.2	0.2	0.2
Alternative Fuel On-Road	**+**	**+**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Non-Road[c]	**6.2**	**8.1**	**7.6**	**6.7**	**7.4**	**7.7**	**7.9**
Ships and Boats	0.2	0.2	0.2	0.1	0.3	0.3	0.2
Rail[d]	0.2	0.4	0.2	0.2	0.2	0.2	0.2
Aircraft	1.5	1.6	1.5	1.0	1.3	1.4	1.5

Fuel Type/Vehicle Type[a]	1990	2005	2019	2020	2021	2022	2023
Agricultural Equipment[e]	1.2	1.4	1.1	1.1	1.1	1.1	1.1
Construction/Mining Equipment[f]	1.2	1.9	1.7	1.6	1.7	1.7	1.7
Other[g]	1.8	2.8	2.9	2.7	2.9	3.1	3.2
Total	**37.8**	**42.0**	**18.8**	**16.0**	**16.8**	**16.6**	**16.2**

+ 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. VMT for 2023 is estimated based on trends in FHWA's Traffic Volume Trends data series. VMT estimates from FHWA are allocated to vehicle type using ratios of VMT per vehicle type to total VMT, derived from EPA's MOVES5 model (see Annex 3.2 for information about the MOVES model).
[c] Nonroad fuel consumption estimates for 2020 are adjusted to account for the COVID-19 pandemic and associated restrictions. For agricultural equipment and airport equipment, sector specific adjustment factors were applied to the 2019 data. For all other sectors, a 7.7 percent reduction factor is used, based on transportation diesel use (EIA 2025a).
[d] Rail emissions do not include emissions from electric powered locomotives. Class II and Class III diesel consumption data for 2014 through 2023 is estimated by applying the historical average fuel usage per carload factor to the annual number of carloads.
[e] Includes equipment, such as tractors and combines, as well as fuel consumption from trucks that are used off-road in agriculture.
[f] Includes equipment, such as cranes, dumpers, and excavators, as well as fuel consumption from trucks that are used off-road in construction.
[g] "Other" includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment, as well as fuel consumption from trucks that are used off-road for commercial/industrial purposes.
Note: Totals may not sum due to independent rounding.

CO_2 from Fossil Fuel Combustion

Methodology and Time-Series Consistency

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) Chapter 2, Figure 2.1 decision tree and available data on energy use and country specific fuel carbon contents with some exceptions as discussed below.[27] 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 2025a). 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 2024a), see Annex 2.1 for more details on how Territories data is collected.[28]
2. 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

27 The IPCC Tier 3B methodology is used for estimating emissions from commercial aircraft.
28 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 25.3 MMT CO_2 Eq. in 2023.

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.[29]

3. 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).[30]

4. *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 2021), Coffeyville (2012), U.S. Census Bureau (2001 through 2011), EIA (2024a, 2024f, 2024h), USAA (2008 through 2021), USGS (1991 through 2020), (USGS 2019), USGS (2014 through 2021a), USGS (2014 through 2021b), USGS (1995 through 2013), USGS (1995, 1998, 2000, 2001, 2002, 2007), USGS (2021a), USGS (1991 through 2015a), USGS (1991 through 2020), USGS (2014 through 2021a), USGS (1991 through 2015b), USGS (2021b), USGS (1991 through 2020).[31]

5. *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.[32] 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.[33]

6. *Adjust for CO_2 sequestration.* Since October 2000, the Dakota Gasification Plant has been exporting CO_2 produced in the coal gasification process to Canada by pipeline. Because this

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[29] 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.

[30] 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.

[31] 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.

[32] Natural gas energy statistics from EIA (2024d) are already adjusted downward to account for biogas in natural gas.

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

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 (2024h) 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 (2025). A discussion of the methodology used to estimate the amount of CO_2 captured and exported by pipeline is presented in Annex 2.1.

Additionally in 2023, the Petra Nova facility reported to the GHGRP subpart RR sequestration of CO_2 that was captured from a coal fired power plant. Because the sequestered CO_2 is assumed to not be admitted to the atmosphere, the CO_2 captured for sequestration was needed out of CO_2 emissions from electric power sector coal. See Section 3.9 for more information on CO_2 transport, injection and geologic sequestration accounting in the Inventory.

7. *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 2022), Benson (2002 through 2004), DOE (1993 through 2022), EIA (2007), EIA (2025a), EPA (2024e), and FHWA (1996 through 2024).[34]

8. *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 carbon contained in the fuel for a period of time. As the emission pathways of carbon used for non-energy purposes are vastly different than fuel combustion (since the carbon in these fuels ends up in products instead of being combusted), these emissions are estimated separately in Section 3.2. 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 (2025a).

9. *Subtract consumption of international bunker fuels.* In line with IPCC guidelines emissions from international transport activities, or bunker fuels, should not be included in national totals. U.S. energy consumption statistics include these bunker fuels (e.g., distillate fuel oil, residual fuel oil, and jet fuel) as part of consumption by the transportation end-use sector, however, so emissions from international transport activities were calculated separately following the same procedures used to calculate emissions from consumption of all fossil fuels (i.e., estimation of consumption, and determination of carbon content).[35] The Office of the Under Secretary of

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[34] 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 2024).

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

Defense (Installations and Environment) and the Defense Logistics Agency Energy (DLA Energy) of the U.S. Department of Defense (DoD) (DLA Energy 2025) supplied data on military jet fuel and marine fuel use. Commercial jet fuel use was estimated based on data from FAA (2024) and DOT (1991 through 2023); residual and distillate fuel use for civilian marine bunkers was obtained from DOC (1991 through 2024) for 1990 through 2001 and 2007 through 2020, and DHS (2008) for 2003 through 2006.[36] 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 3.9.

10. *Determine the total carbon content of fuels consumed.* Total carbon was estimated by multiplying the amount of fuel consumed by the amount of carbon in each fuel. This total carbon estimate defines the maximum amount of carbon that could potentially be released to the atmosphere if all of the carbon in each fuel was converted to CO_2. A discussion of the methodology and sources used to develop the carbon content coefficients are presented in Annexes 2.1 and 2.2.

11. *Estimate CO_2 emissions.* Total CO_2 emissions are the product of the adjusted energy consumption (from the previous methodology steps 1 through 7), the carbon content of the fuels consumed, and the fraction of carbon 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 carbon (44/12) to obtain total CO_2 emitted from fossil fuel combustion in million metric tons (MMT).

12. *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 (2024f) and USAF (1998).[37]

    - For on-road vehicles, annual estimates of combined motor gasoline and diesel fuel consumption by vehicle category were obtained from FHWA (1996 through 2024); for each vehicle category, the percent gasoline, diesel, and other (e.g., CNG, LPG) fuel consumption are estimated using data from EPA's MOVES model and DOE (1993 through 2022).[38,39]

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

[37] 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 3.3, respectively.

[38] On-road fuel consumption data from FHWA Table MF-21 and MF-27 were used to determine total on-road use of motor gasoline and diesel fuel (FHWA 1996 through 2023). Ratios developed from MOVES5 output are used to apportion FHWA fuel consumption data to vehicle type and fuel type (see Annex 3.2 for information about the MOVES model). Trends in on-road vehicle VMT and fuel consumption are proxied based on the Traffic Volume Trends data for the year 2023.

[39] Transportation sector natural gas and LPG consumption are based on data from EIA (2025a). In previous Inventory years, data from DOE (1993 through 2022) 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 1990 through 2015 Inventory and apply to the time period from 1990 to 2015.

- For non-road vehicles, activity data were obtained from AAR (2008 through 2023), APTA (2007 through 2023), APTA (2006), BEA (1991 through 2015), Benson (2002 through 2004), DLA Energy (2025), DOC (1991 through 2024), DOE (1993 through 2023), DOT (1991 through 2025), EIA (2009a), EIA (2024c), EIA (2002), EIA (1991 through 2022), EPA (2024a),[40] 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. 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.

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990 through 2023. Due to data availability and sources, some adjustments outlined in the methodology above are not applied consistently across the full 1990 to 2023 time series. As described in greater detail in Annex 2.1, to align with EIA's methodology for calculating motor gasoline consumption, petroleum denaturant adjustments are applied to motor gasoline consumption only for the period 1993 through 2008. In addition to ensuring time-series consistency, 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 from the Dakota Gasification Plant is adjusted to align with the Canadian National Greenhouse Gas Inventory (Environment and Climate Change Canada 2025). This adjustment is explained in greater detail in Annex 2.1. 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.

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

The amount of carbon emitted from the combustion of fossil fuels is dependent upon the carbon content of the fuel and the fraction of that carbon 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

[40] In 2014, EPA incorporated the NONROAD2008 model into the MOVES model framework (EPA 2024b). The current *Inventory* uses the Nonroad component of MOVES5 for years 1999 through 2023.

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 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 carbon 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.

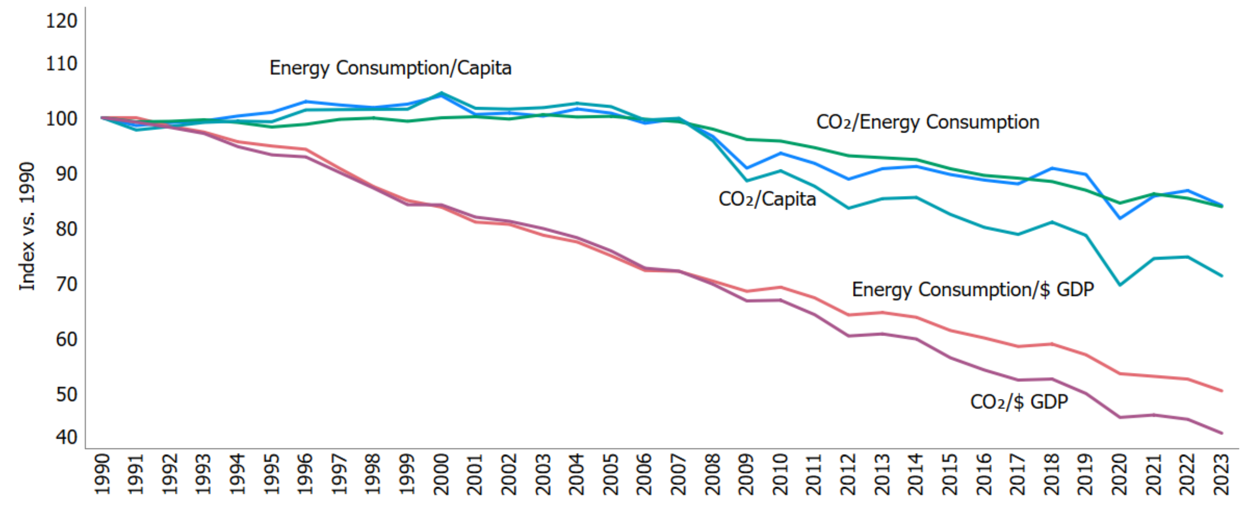
Table 3-16: Carbon Intensity from Direct Fossil Fuel Combustion by Sector (MMT CO_2 Eq./QBtu)

Sector	1990	2005	2019	2020	2021	2022	2023
Residential[a]	57.4	56.8	55.3	55.1	55.2	55.2	55.3
Commercial[a]	59.7	57.8	56.2	56.3	56.2	56.6	56.4
Industrial[a]	64.8	64.6	60.2	59.6	59.6	59.6	59.3
Transportation[a]	71.1	71.5	70.9	70.8	70.9	70.8	70.8
Electric Power[b]	87.3	85.8	72.9	70.5	72.4	70.9	68.2
U.S. Territories[c]	73.1	73.4	70.8	71.5	70.1	71.6	69.9
All Sectors[c]	**73.1**	**73.6**	**67.3**	**66.3**	**67.0**	**66.5**	**65.7**

[a] Does not include electricity or renewable energy consumption.
[b] Does not include electricity produced using nuclear or renewable energy.
[c] Does not include nuclear or renewable energy consumption.
Notes: Excludes non-energy fuel use emissions and consumption. Totals may not sum due to independent rounding.

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 of U.S. energy consumption 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 2023, was approximately 15.8 percent below levels in 1990 (see Table 3-17). To differentiate these estimates from those of Table 3-16, the carbon intensity trend shown in Table 3-17 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 2024).

Table 3-17: 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 (2023c), EPA (2010), and fossil fuel consumption data as discussed above and presented in Annex 2.1.

Uncertainty

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 carbon emitted from non-energy uses of fossil fuels can be found within that section of this chapter.

Various sources of uncertainty surround the estimation of emissions from international bunker fuels, which are subtracted from the U.S. totals (see the detailed discussions on these uncertainties provided in Section 3.9). 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.[41] 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.[42]

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

[41] 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.

[42] 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.

associated with these variables (SAIC/EIA 2001).[43] For purposes of this uncertainty analysis, each input variable was simulated 10,000 times through Monte Carlo sampling.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-18. Fossil fuel combustion CO_2 emissions in 2023 were estimated to be between 4,465.9 and 4,753.8 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 2 percent below to 4 percent above the 2023 emission estimate of 4,559.4 MMT CO_2 Eq.

Table 3-18: 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)

		Uncertainty Range Relative to Emission Estimate[a]			
		(MMT CO_2 Eq.)		(%)	
Fuel/Sector	2023 Emission Estimate (MMT CO_2 Eq.)	Lower Bound	Upper Bound	Lower Bound	Upper Bound
Coal[b]	**734.7**	**709.8**	**804.2**	**-3%**	**9%**
Residential	NO	NO	NO	NO	NO
Commercial	1.1	1.1	1.3	-5%	15%
Industrial	36.5	34.7	42.2	-5%	16%
Transportation	NO	NO	NO	NO	NO
Electric Power	694.6	668.0	762.0	-4%	10%
U.S. Territories	2.5	2.2	3.0	-12%	19%
Natural Gas[b]	**1,725.8**	**1,704.6**	**1,805.0**	**-1%**	**5%**
Residential	247.5	240.5	264.8	-3%	7%
Commercial	182.8	177.7	195.6	-3%	7%
Industrial	514.8	498.1	552.8	-3%	7%
Transportation	71.7	69.7	76.8	-3%	7%
Electric Power	704.5	684.2	740.6	-3%	5%
U.S. Territories	4.5	3.9	5.2	-12%	17%
Petroleum[b]	**2,098.5**	**1,974.3**	**2,223.2**	**-6%**	**6%**
Residential	59.6	56.2	62.8	-6%	5%
Commercial	60.2	56.9	63.5	-5%	5%
Industrial	241.3	186.8	296.7	-23%	23%
Transportation	1,704.7	1,597.2	1,812.3	-6%	6%
Electric Power	14.7	14.1	15.7	-4%	7%
U.S. Territories	17.9	16.6	19.7	-7%	10%
Geothermal	**0.4**	**0.2**	**1.1**	**-46%**	**187%**
Electric Power	0.4	0.2	1.1	-46%	187%
Total (including Geothermal)[b]	**4,559.4**	**4,465.9**	**4,753.8**	**-2%**	**4%**

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

[43] 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.

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.

One area of QA/QC and verification is to compare the estimates and emission factors used in the *Inventory* with other sources of CO_2 emissions reporting. Two main areas and sources of data were considered. The first is a comparison with the EPA GHGRP combustion data (Subpart C) for stationary combustion sources excluding the electric power sector. This mainly focused on considering carbon factors for natural gas. The second comparison is with the EPA Air Markets Program data for electric power production. This considered carbon factors for coal and natural gas used in electric power production.

The EPA GHGRP collects greenhouse gas emissions data from large emitters including information on fuel combustion. This excludes emissions from mobile sources and smaller residential and commercial sources, those emissions are covered under supplier reporting (Subparts MM and NN) and are areas for further research. Fuel combustion CO_2 data reported in 2023 was 1,969.1 MMT CO_2. Of that, 1,465.2 MMT CO_2 was from electricity production. Therefore, the non-electric power production fuel combustion reporting was a fraction of the total covered by the *Inventory* under fossil fuel combustion. Furthermore, reporters under the GHGRP can use multiple methods of calculating emissions; one method is to use the default emission factors provided in the rule, while another is based on a Tier 3 approach using their own defined emission factors. Based on data from reporters on approach used, it was determined that only about 10 percent of natural gas combustion emissions were based on a Tier 3 approach. Given the small sample size compared to the overall *Inventory* calculations for natural gas combustion EPA determined it was not reasonable to consider the GHGRP Tier 3 natural gas factors at this time. A more detailed analysis was done on upstream oil and gas natural gas combustion emissions using the GHGRP data as discussed in Annex 2.2.

EPA collects detailed sulfur dioxide (SO_2), nitrogen oxides (NO_X), and carbon dioxide (CO_2) emissions data and other information from power plants across the country as part of the Acid Rain Program (ARP), the Cross-State Air Pollution Rule (CSAPR), the CSAPR Update, and the Revised CSAPR Update (RCU). The CO_2 data from these Air Market Programs (AMP) can be compared to the electric power sector emissions calculated from the *Inventory* as shown in Table 3-19 for the three most recent years of data.

Table 3-19: Comparison of Electric Power Sector Emissions (MMT CO_2 Eq. and Percent)

	CO_2 Emissions (MMT CO_2 Eq.)			% Change	
Fuel/Sector	**2021**	**2022**	**2023**	**2021-2022**	**2022-2023**
Inventory Electric Power Sector	**1,540.9**	**1,531.7**	**1,414.2**	**-0.6%**	**-7.7%**
Coal	910.1	851.5	694.6	-6.4%	-18.4%
Natural Gas	612.8	659.3	704.5	7.6%	6.9%
Petroleum	17.7	20.5	14.7	15.9%	-28.3%

Fuel/Sector	CO_2 Emissions (MMT CO_2 Eq.)			% Change	
	2021	2022	2023	2021-2022	2022-2023
AMP Electric Power Sector	**1,524.2**	**1,513.6**	**1,404.0**	**-0.7%**	**-7.2%**
Coal	913.4	858.5	706.5	-6.0%	-17.7%
Natural Gas	609.6	652.7	695.7	7.1%	6.6%
Petroleum	1.3	2.5	1.8	83.6%	-29.1%

Note: Totals may not sum due to independent rounding.

In general, the emissions and trends from the two sources line up well. There are differences expected based on coverage and scope of each source. The *Inventory* covers all emissions from the electric power sector as defined above. The EPA AMP data covers emissions from electricity generating units of a certain size so in some respects it could cover more sources (like electric power units at industrial facilities that would be covered under the industrial sector in the *Inventory*) and not as many sources (since smaller units are excluded). The EPA AMP data also includes heat input for different fuel types. That data can be combined with emissions to calculate implied emission factors.[44] The following Table 3-20 shows the implied emissions factors for coal and natural gas from the EPA AMP data compared to the factors used in the *Inventory* for the three most recent years of data.

Table 3-20: Comparison of Emissions Factors (MMT Carbon/QBtu)

Fuel Type	2021	2022	2023
EPA AMP			
Coal	25.67	25.54	25.47
Natural Gas	14.60	14.61	14.60
EPA *Inventory*			
Electric Power Coal	26.13	26.13	26.15
Natural Gas	14.43	14.43	14.43

The factors for natural gas line up reasonably well, the EPA factors are roughly 1 percent lower than those calculated from the EPA AMP data. For coal the EPA emissions factors are roughly 2 to 3 percent higher than those calculated from the EPA AMP data. One possible reason for the difference is that the EPA *Inventory* factors are based on all coal and natural gas used in electric power production while the factors from the EPA AMP data are based on units where coal or natural gas is the primary source of fuel used. There are units that use a mix of fuel sources but emissions for each fuel type could not be calculated. This is an area of further research but given current data available the approach to develop carbon factors as outlined in Annex 2 is still felt to be the most appropriate to represent total fuel combustion in the United States.

A "top-down" reference approach for estimating CO_2 emissions from fossil fuel combustion in addition to a “bottom-up” sectoral methodology is good practice in line with IPCC guidelines. 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,

[44] These emission factors can be converted from MMT Carbon/QBtu to MMT CO_2 Eq./QBtu by multiplying the emission factor by 44/12, the molecular-to-atomic weight ratio of CO_2 to C. This would assume the fraction oxidized to be 100 percent, which is the guidance in IPCC (2006) (see Annex 2.1).

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

EIA (2025a) updated natural gas consumed by all sectors in 2020 and 2022, as well as petroleum consumed by all sectors in 2021 and 2022. Additionally, EIA (2024a) updated U.S. Territories petroleum for the years 2020 through 2022, and U.S. Territories natural gas and coal consumption for the year 2022These updates caused total CO_2 emissions to increase by an annual average of 0.01 MMT CO_2 Eq. (less than 0.05 percent) in the years 1990 through 2022 compared to the previous *Inventory*.

Planned Improvements

To reduce the 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. Additionally, although not technically a fossil fuel, since geothermal energy-related CO_2 emissions are included for reporting purposes, further expert elicitation may be conducted to better quantify the total uncertainty associated with CO_2 emissions from geothermal energy use.

EPA will continue to examine the availability of facility-level combustion emissions through EPA's GHGRP 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, although 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 in this chapter, some facility-level fuel combustion emissions reported under the GHGRP may also include industrial process emissions. In line with IPCC 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, additional work will look at CO_2 emissions from biomass to ensure they are separated in the facility-level reported data and maintaining consistency with national energy statistics provided by EIA. In implementing improvements and integration of data from EPA's GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will continue to be relied upon.[45]

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

EPA is also evaluating the methods used to adjust for conversion of fuels and exports of CO_2. EPA is including an approach used to account for CO_2 transport, injection, and geologic storage in this *Inventory,* as part of this ongoing work there may be changes made to the accounting for CO_2 exports.

Finally, another ongoing planned improvement is to evaluate data availability to update the carbon and heat content of more fuel types accounted for in this *Inventory*. This update will impact consumption and emissions across all sectors and will improve consistency with EIA data as carbon and heat contents of fuels will be accounted for as annually variable and therefore improve accuracy across the time series. Some of the fuels considered in this effort include petroleum coke, residual fuel, and woody biomass.

CH_4 and N_2O from Stationary Combustion

Methodology and Time-Series Consistency

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 in accordance with IPCC methodological decision tree Figure 2.1 in the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC 2006) and available data. 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 2025). 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 2024).[46] 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 (2024b) and FHWA (1996 through 2024). 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 are included under waste incineration (Section 3.3). Estimates for natural gas combustion do not include biogas, and therefore non-CO_2 emissions from biogas are not included (see the Planned Improvements section, below). Tier 1 default emission factors for the industrial, commercial, and residential end-use sectors were provided by the *2006 IPCC 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.

[46] 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 is based on EPA's Acid Rain Program Dataset (EPA 2024). Total fuel consumption in the electric power sector from EIA (2025) was apportioned to each combustion technology type and fuel combination using a ratio of fuel consumption by technology type derived from EPA (2024a) data. The combustion technology and fuel use data by facility obtained from EPA (2024a) were only available from 1996 to 2023 so the consumption estimates from 1990 to 1995 were estimated by applying the 1996 consumption ratio by combustion technology type from EPA (2024a) to the total EIA (2024a) 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.[47]

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.

Uncertainty

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.[48] For these variables, the uncertainty ranges were assigned to the input variables based on the data reported in

[47] Several of the U.S. Tier 2 emission factors were used in IPCC (2006) as Tier 1 emission factors. See Table A-68 in Annex 3.1 for emission factors by technology type and fuel type for the electric power sector.

[48] 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.

SAIC/EIA (2001).[49] 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 3-101. Stationary combustion CH_4 emissions in 2023 (including biomass) were estimated to be between 5.8 and 19.7 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 34 percent below to 125 percent above the 2023 emission estimate of 8.8 MMT CO_2 Eq.[50] Stationary combustion N_2O emissions in 2023 (including biomass) were estimated to be between 15.0 and 29.5 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 23 percent below to 51 percent above the 2023 emission estimate of 19.6 MMT CO_2 Eq.

Table 3-21: 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	2023 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	8.8	5.8	19.7	-34%	+125%
Stationary Combustion	N_2O	19.6	15.0	29.5	-23%	+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.

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.

49 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.

50 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.

Recalculations Discussion

EPA adjusted the share of total consumption apportioned to each combustion technology type for 2022 to correct a previous error. EIA (2025) updated the heat constant of bituminous coal for the time series. EIA (2025) updated natural gas consumed by all sectors in 2020 and 2022, as well as petroleum consumed by all sectors in 2021 and 2022. EIA (2025) also updated electricity statistics which affected commercial sector wood consumption for the years 2014 through 2022. Additionally, EIA (2024) updated U.S. Territories petroleum for the years 2020 through 2022, and U.S. Territories natural gas and coal consumption for the year 2022. These updates resulted in an average annual decrease of less than 0.5 MMT CO_2 Eq. (0.1 percent) in CH_4 emissions and an average annual decrease of 0.1 MMT CO_2 Eq. (0.3 percent) in N_2O emissions across the time series compared to the previous *Inventory*.

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. The CH_4 emission factor for residential wood combustion developed by NESCAUM (2024) will also be reviewed and potentially incorporated based on this review. Factors for methane slip will also be reviewed. 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. As an additional planned improvement, 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 (2024a) 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 and Time-Series Consistency

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.51

CH_4 and N_2O emissions factors by vehicle type and emission tier 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 earlier emission factors were derived from EPA, California Air Resources Board (CARB) and Environment and Climate Change Canada (ECCC) laboratory test results of different vehicle and control technology types. The EPA, CARB and ECCC 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 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 grams per mile emissions of CO_2, CO, HC, NO_x, and PM from vehicles under various conditions.[52]

Diesel on-road vehicle emission factors were developed by ICF (2006). CH_4 and N_2O emissions factors for newer (starting with 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 2023 Greenhouse gases, Regulated Emissions, and Energy use in Transportation (GREET) model (ANL 2023). For light-duty trucks, EPA used travel fractions for LDT1 and LDT2 (MOVES Source Type 31 for LDT1 and MOVES Source Type 32 for LDT2; see Annex 3.2 for information about the MOVES model) to determine emission factors. 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 2022 were obtained from the Federal Highway Administration's (FHWA) Highway Performance Monitoring System database as reported in Highway Statistics (FHWA 1996 through 2024). VMT data for 2023 was proxied based on FHWA's Traffic Volume Trends Data for 2023. VMT estimates were then allocated to vehicle type using ratios of VMT per vehicle type to total VMT, derived from EPA's MOVES5 model (see Annex 3.2 for information about the MOVES model). This corrects time series inconsistencies in FHWA definitions of vehicle types (Browning 2022a). VMT for alternative fuel vehicles (AFVs) were estimated based on Browning (2024). The age distributions of the

51 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.

52 Additional information regarding the MOBILE model can be found at https://www.epa.gov/moves/description-and-history-mobile-highway-vehicle-emission-factor-model.

U.S. vehicle fleet were obtained from EPA (2004, 2024a), and the average annual age-specific vehicle mileage accumulation of U.S. vehicles were obtained from EPA (2024a).

Control technology and standards data for on-road vehicles were obtained from EPA's Office of Transportation and Air Quality (EPA 1998, 2022b, 2023, and 2024) and Browning (2005). These technologies and standards are defined in Annex 3.2, and were compiled from EPA (1994a, 1994b, 1998, 1999) and IPCC (2006) sources.

Non-Road Mobile Sources

The nonroad mobile category for CH_4 and N_2O includes ships and boats, aircraft, locomotives, and other mobile non-road sources (e.g., construction or agricultural equipment). For locomotives, aircraft, ships, and non-recreational boats, fuel-based emission factors are applied to data on fuel consumption, following the IPCC Tier 1 approach, The Tier 2 approach for these sources would require separate fuel-based emissions factors by technology, for which data are not currently available. For other non-road sources, EPA uses the Nonroad component of the MOVES model to estimate fuel use. Emission factors by horsepower bin are estimated from EPA engine certification data. Because separate emission factors are applied to specific engine technologies; these non-road sources utilize 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).[53] Activity data were obtained from AAR (2008 through 2024), APTA (2007 through 2024), Rail Inc (2014 through 2024), APTA (2006), BEA (1991 through 2015), Benson (2002 through 2004), Bureau of Transportation Statistics (BTS; 2023), DLA Energy (2025), DOC (1991 through 2024), DOE (1993 through 2022), DOT (1991 through 2024), EIA (2002, 2007, 2024, 2023), EIA (1991 through 2023), EPA (2024a), Esser (2003 through 2004), FAA (2022), FHWA (1996 through 2024),[54] Gaffney (2007), FTA (2023), and Whorton (2006 through 2014). Fuel consumption data regarding jet fuel, on-road vehicles, and diesel consumption in US territories and vessel bunking were proxied from 2022, awaiting publication of updated data. Fuel consumption data for boats and vessels in U.S. Territories data and vessel domestic vessel bunkering is proxied from 2022 proxy data. Emission factors for non-road modes were taken from IPCC (2006) and Browning (2020 and 2018).

Uncertainty

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 2023 estimates of CH_4 and N_2O emissions, incorporating probability distribution functions associated with the major input

[53] 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.

[54] 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_2O 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.

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 3.11. 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 2023 were estimated to be between 2.5 and 3.3 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 4 percent below to 30 percent above the corresponding 2023 emission estimate of 2.5 MMT CO_2 Eq. Mobile combustion N_2O emissions from mobile sources in 2023 were estimated to be between 15.1 and 19.8 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 7 percent below to 22 percent above the corresponding 2023 emission estimate of 16.2 MMT CO_2 Eq.

Table 3-22: Approach 2 Quantitative Uncertainty Estimates for CH_4 and N_2O Emissions from Mobile Sources (MMT CO_2 Eq. and Percent)

Source	Gas	2023 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
Mobile Sources	CH_4	2.5	2.5	3.3	-4%	+30%
Mobile Sources	N_2O	16.2	15.1	19.8	-7%	+22%

[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

New data on the activity of battery and plug-in hybrid electric vehicles was used to estimate electric vehicle mileage (Browning, 2024). Past inventories estimated that electric vehicles had similar mileage accumulation to conventionally fueled vehicles. The current inventory uses more recent data that shows electric vehicles drive fewer miles annually than the average conventionally fueled vehicle. This annual mileage update resulted in total CO_2 emissions from electricity consumption by electric vehicles to decrease by 1.6 MMT (26 percent) in 2022 and 1.1 MMT in 2021 (22 percent), compared to the previous Inventory. CH_4 and N_2O emissions are not impacted by this update.

Updated alternative fuel emissions factors based on the latest GREET model (GREET 2023) were also included. As a result of these updates, CH_4 emissions from alternative fuel vehicles increased by an annual average of .01 MMT CO_2 Eq. (27 to 30 percent) in the years 2020 through 2022 compared to the previous Inventory. Alternative fuel vehicle N_2O emissions decreased by .01 MMT CO_2 Eq. (8 percent) in 2022 and changes in N_2O emissions in 2020 and 2021 were less than .01 MMT CO_2 Eq., relative to the previous Inventory.

Output from the recently released MOVES5 model was used to update the vehicle fleet composition by age and type and the estimated mileage and fuel use by vehicle type and model year. This change affects the historical time series of emissions by vehicle type. A significant component of this change is replacing projections based on MOVES3, with actual vehicle fleet data from MOVES5. MOVES5 also includes more accurate projections based on the most recent data. Due to this update, N_2O emissions from gasoline powered highway vehicles increased by 0.03 MMT CO_2 Eq. (0.4 percent) in 2021 and 0.08 MMT CO_2 Eq. (1.5 percent) in 2022 compared to the previous Inventory. Total N_2O emissions for diesel highway vehicles increased by less than 0.01 MMT CO_2 Eq. (0.1 percent) in 2021 and decreased by 0.1 MMT CO_2 Eq (2.9 percent) in 2022 compared to the previous Inventory. Changes in CH_4 emissions for gasoline highway vehicles were small for 2021 and 2022, between -0.01 MMT CO_2 Eq. (-1.1 percent) in 2021 and less than 0.01 MMT CO_2 Eq. (0.4 percent) in 20222. Changes in CH_4 emissions from diesel highway vehicles were small, decreasing 0.01 MMT CO_2 Eq. (9.4 percent) in 2021 and 0.02 (14.1 percent) in 2022.

Together, these updates resulted in an average annual increase of 0.4 MMT CO_2 Eq. (7.9 percent) in CH_4 emissions and an average annual increase 1.4 MMT CO_2 Eq. (4.8 percent) in N_2O emissions across the time series compared to the previous *Inventory*.

Planned Improvements

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

- Improve estimates of electric vehicle activity and energy use. EIA publishes output from a model that estimates electric vehicle energy consumption starting in 2018 for passenger vehicles. Model results from EIA could be used to improve the estimates of electric vehicle activity and energy use in the Inventory.

- Update emission factors for ships and non-recreational boats using residual fuel and distillate fuel. Develop emission factors for locomotives using ultra-low sulfur diesel and emission factors for aircraft using jet fuel. The Inventory currently uses IPCC default values for these emission 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 U.S. coastlines must use distillate fuels, thereby overestimating the residual fuel used by U.S. vessels and underestimating distillate fuel use in these ships. Additionally, the EIA has stopped publishing the Fuel Oil and Kerosene Sales report, which reported data on distillate marine fuel use in the U.S. and the territories. This affects the volume of fuel and emissions that are allocated to the domestic ships and boats source, although top-down data is still available from the Monthly Energy Review that will be used to estimate total domestic emission from diesel fuel use. New data and methods are being explored to improve the diesel ships and boats emissions estimates going forward.

3.2 Carbon Emitted from Non-Energy Uses of Fossil Fuels (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),[55] 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

[55] 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, isobutane, and natural gasoline (formerly referred to as pentanes plus), and HGLs include olefins, such as ethylene, propylene, butylene and isobutylene.

feedstocks. Additionally, emissions may occur during the product's lifetime, such as during solvent use. Overall, throughout the time series and across all uses, about 64 percent of the total carbon consumed for non-energy purposes was stored in products (e.g., plastics), and not released to the atmosphere; the remaining 36 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 carbon in non-energy applications.

As shown in Table 3-23, fossil fuel emissions in 2023 from the non-energy uses of fossil fuels were 107.1 MMT CO_2 Eq., which constituted approximately 2.2 percent of overall fossil fuel emissions. In 2023, the consumption of fuels for non-energy uses (after the adjustments described above) was 5,570.9 TBtu (see Table 3-24). A portion of the carbon in the 5,570.9 TBtu of fuels was stored (240.9 MMT CO_2 Eq.), while the remaining portion was emitted (107.1 MMT CO_2 Eq.). Non-energy use emissions increased by 5.3 percent from 2022 to 2023, primarily due to increases in HGL production, industry lubricants, and transportation lubricants. See Annex 2.3 for more details.

Table 3-23: CO_2 Emissions from Non-Energy Use Fossil Fuel Consumption (MMT CO_2 Eq. and Percent C)

Year	1990	2005	2019	2020	2021	2022	2023
Potential Emissions	292.5	357.7	334.7	328.7	345.1	338.5	348.0
C Stored	193.4	232.7	228.2	230.8	233.4	236.8	240.9
Emissions as a % of Potential	34%	35%	32%	30%	32%	30%	31%
C Emitted	**99.1**	**125.0**	**106.5**	**97.9**	**111.7**	**101.7**	**107.1**

Notes: NEU emissions presented in this table differ from the NEU emissions presented in the common data tables since those report NEU emissions from U.S. Territories under the U.S. Territories category and not under the NEU category. Totals may not sum due to independent rounding.

Methodology and Time-Series Consistency

As per discussion of methodology for estimating CO_2 emissions from fossil fuel combustion, NEU emissions 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) Chapter 2, Figure 2.1 decision tree and available data on energy use and country specific fuel carbon contents. The first step in estimating carbon stored in products was to determine the aggregate quantity of fossil fuels consumed for non-energy uses. The carbon content of these feedstock fuels is equivalent to potential emissions, or the product of consumption and the fuel-specific carbon content values. Both the non-energy fuel consumption and carbon content data were supplied by the EIA (2024) (see Annex 2.1). Consumption values for industrial coking coal, petroleum coke, other oils, and natural gas in Table 3-24 and Table 3-25 have been adjusted to subtract non-energy uses that are included in the source categories of the Industrial Processes and

Product Use chapter.[56] Consumption of natural gas, HGL, 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 carbon 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, naphthas, other oils, still gas, special naphtha, and industrial other coal), asphalt and road oil, lubricants, and waxes—U.S. data on carbon stocks and flows were used to develop carbon storage factors, calculated as the ratio of (a) the carbon stored by the fuel's non-energy products to (b) the total carbon content of the fuel consumed. A lifecycle approach was used in the development of these factors in order to account for losses in the production process and during use. Because losses associated with municipal solid waste management are handled separately in the Energy sector under the Incineration of Waste source category, the storage factors do not account for losses at the disposal end of the life cycle.
- For industrial coking coal and distillate fuel oil, storage factors were taken from 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 carbon 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 3-24: Adjusted Consumption of Fossil Fuels for Non-Energy Uses (TBtu)

Year	1990	2005	2019	2020	2021	2022	2023
Industry	**4,110.2**	**4,961.2**	**5,144.0**	**5,096.3**	**5,342.2**	**5,281.0**	**5,472.4**
Industrial Coking Coal	NO	80.4	113.0	79.4	77.5	46.4	65.4
Industrial Other Coal	7.6	11.0	9.5	9.5	9.5	9.5	9.5
Natural Gas to Chemical Plants	280.6	260.7	663.4	660.5	663.6	654.9	663.7
Asphalt & Road Oil	1,170.2	1,323.2	843.9	832.3	898.1	916.1	891.8
HGL[a]	1,135.0	1,554.3	2,372.8	2,469.5	2,638.6	2,742.4	2,968.1
Lubricants	186.3	160.2	118.3	111.1	113.5	115.0	86.3
Natural Gasoline[b]	NO	NO	NO	NO	NO	NO	NO
Naphtha (<401 °F)	325.4	679.2	367.7	327.8	329.2	244.1	252.8
Other Oil (>401 °F)	660.4	499.2	211.1	194.7	195.3	111.0	104.6
Still Gas	36.7	67.7	158.7	145.4	152.8	157.1	155.8
Petroleum Coke	29.1	104.2	NO	NO	NO	NO	NO
Special Naphtha	100.6	60.9	89.1	80.4	75.7	82.4	83.4
Distillate Fuel Oil	7.0	16.0	5.8	5.8	5.8	5.8	5.8
Waxes	33.3	31.4	10.4	9.2	11.8	13.0	9.0

[56] 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.

Year	1990	2005	2019	2020	2021	2022	2023
Miscellaneous Products	137.8	112.8	180.2	170.7	170.8	183.4	176.2
Transportation	**176.0**	**151.3**	**131.3**	**115.6**	**119.0**	**129.9**	**97.5**
Lubricants	176.0	151.3	131.3	115.6	119.0	129.9	97.5
U.S. Territories	**50.8**	**114.9**	**3.6**	**3.5**	**3.5**	**1.0**	**1.0**
Lubricants	0.7	4.6	1.0	1.0	1.0	1.0	1.0
Other Petroleum (Misc. Prod.)	50.1	110.3	2.6	2.5	2.5	NO	NO
Total	**4,337.1**	**5,227.5**	**5,278.9**	**5,215.4**	**5,464.7**	**5,412.0**	**5,570.9**

NO (Not Occurring)
[a] Excludes natural gasoline.
[b] Formerly referred to as "pentanes plus." This source has been adjusted and is reported separately from HGL to align with historic data and revised EIA terminology.
Note: Totals may not sum due to independent rounding.

Table 3-25: 2023 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 (MMT C)	Carbon Stored (MMT C)	Carbon Emissions (MMT C)	Carbon Emissions (MMT CO_2 Eq.)
Industry	**5,472.4**	**NA**	**92.9**	**NA**	**65.5**	**27.4**	**100.4**
Industrial Coking Coal	65.4	25.6	1.7	0.1	0.2	1.5	5.5
Industrial Other Coal	9.5	26.1	0.2	0.7	0.2	0.1	0.3
Natural Gas to Chemical Plants	663.7	14.5	9.6	0.7	6.3	3.3	11.9
Asphalt & Road Oil	891.8	20.6	18.3	1.0	18.2	0.1	0.3
HGL[b]	2,968.1	16.8	49.9	0.7	32.9	17.0	62.2
Lubricants	86.3	20.2	1.7	0.1	0.2	1.6	5.8
Natural Gasoline[c]	NO	18.2	NO	0.7	NO	NO	NO
Naphtha (<401° F)	252.8	18.6	4.7	0.7	3.1	1.6	5.8
Other Oil (>401° F)	104.6	20.2	2.1	0.7	1.4	0.7	2.6
Still Gas	155.8	17.5	2.7	0.7	1.8	0.9	3.4
Petroleum Coke	NO	27.8	NO	0.3	NO	NO	NO
Special Naphtha	83.4	19.7	1.6	0.7	1.1	0.6	2.1
Distillate Fuel Oil	5.8	20.2	0.1	0.5	0.1	0.1	0.2
Waxes	9.0	19.8	0.2	0.6	0.1	0.1	0.3
Miscellaneous Products	176.2	NO	NO	NO	NO	NO	NO
Transportation	**97.5**	**NA**	**2.0**	**NA**	**0.2**	**1.8**	**6.6**
Lubricants	97.5	20.2	2.0	0.1	0.2	1.8	6.6
U.S. Territories	**1.0**	**NA**	**+**	**NA**	**+**	**+**	**0.1**
Lubricants	1.0	20.2	+	0.1	+	+	0.1
Other Petroleum (Misc. Prod.)	+	20.0	+	0.1	+	+	+
Total	**5,570.9**		**94.9**		**65.7**	**29.2**	**107.1**

+ 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.

[b] Excludes natural gasoline.
[c] Formerly referred to as "pentanes plus." this source has been adjusted and is reported separately from HGL to align with historic data and revised EIA terminology.
Note: Totals may not sum due to independent rounding.

Lastly, emissions were estimated by subtracting the carbon stored from the potential emissions (see Table 3-23). 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), EPA's Emissions Inventory System (EIS) to National Inventory Report (NIR) Mapping file (EPA 2025), *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, 2024b), 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, 2021); Bank of Canada (2012, 2013, 2014, 2016, 2017, 2018, 2019, 2020, 2021, 2022, 2023, 2024); Financial Planning Association (2006); INEGI (2006); the United States International Trade Commission (2024); Gosselin, Smith, and Hodge (1984); EPA's *Municipal Solid Waste (MSW) Facts and Figures* (EPA 2013, 2014a, 2016a, 2018a, 2019); the U.S. Tire Manufacturers Association (USTMA 2012, 2013, 2014, 2016, 2018, 2020, 2022, 2024); 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, 2020, 2021, 2022, 2023, 2024a); the *Guide to the Business of Chemistry* (ACC 2024b); and the Chemistry Industry Association of Canada (CIAC 2024). Specific data sources are listed in full detail in Annex 2.3.

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990 through 2023 as discussed below.

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. In this Inventory, carbon storage and carbon emissions from product use of lubricants, waxes, and asphalt and road oil are reported under the Energy sector in the Carbon Emitted from Non-Energy Uses of Fossil Fuels source category (Source Category 1A5).

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., carbon 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 3-25).

For those inputs, U.S. country-specific data on carbon stocks and flows are used to develop carbon storage factors, which are calculated as the ratio of the carbon stored by the fossil fuel non-energy products to the total carbon content of the fuel consumed, taking into account losses in the production process and during product use. The country-specific methodology to reflect national circumstances starts with the aggregate amount of fossil fuels used for non-energy uses and applies a carbon balance calculation, breaking out the carbon 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 carbon emissions separately under IPPU would involve making artificial adjustments to allocate both the carbon inputs and carbon outputs of the non-energy use carbon 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 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 carbon balance and a less transparent approach for the Carbon Emitted from Non-Energy Uses of Fossil Fuels source category calculation, the entire calculation of carbon storage and carbon emissions is therefore conducted in the Non-Energy Uses of Fossil Fuels category calculation methodology, and both the carbon storage and carbon 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

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, natural gasoline, naphthas, other oils, still gas, special naphthas, and other industrial coal), (2) asphalt, (3) lubricants, and (4) waxes. For the remaining fuel types (the "other" category in Table 3-24 and Table 3-25) 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 3-26 (emissions) and Table 3-27 (storage factors). Carbon emitted from non-energy uses of fossil fuels in 2023 was estimated to be between 68.2 and 173.6 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 36 percent below to 62 percent above the 2023 emission estimate of 107.1 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 3-26: Approach 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Non-Energy Uses of Fossil Fuels (MMT CO_2 Eq. and Percent)

Source	Gas	2023 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	88.3	51.7	156.0	-42%	+77%
Asphalt	CO_2	0.3	0.1	0.6	-58%	+116%
Lubricants	CO_2	12.4	10.3	14.4	-17%	+16%
Waxes	CO_2	0.3	0.2	0.6	-26%	+103%
Other	CO_2	5.7	1.1	6.7	-81%	+17%
Total	**CO_2**	**107.1**	**68.2**	**173.6**	**-36%**	**+62%**

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

Table 3-27: Approach 2 Quantitative Uncertainty Estimates for Storage Factors of Non-Energy Uses of Fossil Fuels (Percent)

Source	Gas	2023 Storage Factor (%)	Uncertainty Range Relative to Emission Estimate[a]			
			(%)		(%, Relative)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Feedstocks	CO_2	66.0%	52%	74%	-22%	+13%
Asphalt	CO_2	99.6%	99%	100%	-0.5%	+0.3%
Lubricants	CO_2	9.2%	4%	17%	-59%	+91%
Waxes	CO_2	57.8%	47%	68%	-18%	+17%
Other	CO_2	12.6%	7%	83%	-42%	+555%

[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 3-27, waxes 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—also appears to have relatively 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 11 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 carbon 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.

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 carbon (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 2022 totals as well as their trends across the time series.

It is important to ensure no double counting of emissions between fuel combustion, non-energy use of fuels and industrial process emissions. For petrochemical feedstock production, our review of the categories suggests this is not a significant issue since the non-energy use industrial release data includes different categories of sources and sectors than those included in the Industrial Processes and Product Use (IPPU) emissions category for petrochemicals. Further data integration is not available at this time because feedstock data from the EIA used to estimate non-energy uses of fuels are aggregated by fuel type, rather than disaggregated by both fuel type and particular industries. Also, GHGRP-reported data on quantities of fuel consumed as feedstocks by petrochemical producers are unable to be used due to the data failing GHGRP CBI aggregation criteria. This country-specific approach taken is better able to reflect the national situation because it accounts for secondary product imports and exports that are not included directly in the national energy statistics. Furthermore, it is compatible with the *2006 IPCC Guidelines* as discussed in Box 3-4 above, but also as the NEU emissions are here represent different emissions from those covered in the IPPU petrochemical production category.

Recalculations Discussion

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

- ACC (2023b) updated adipic acid, and acetic acid production in 2022, which resulted in a slight decrease in emissions relative to the previous *Inventory*.
- U.S. International Trade Commission (2024) updated historical import and export data from 2020 to 2022 for cleansers and antifreeze, resulting in slight changes from the previous *Inventory*.
- EIA (2025) updated historical fuel consumption data for HGL, industrial coking coal, and lubricants, resulting in a decrease in emissions for the period 2019 through 2022.
- EPA (2024) published new data on the quantity of hazardous waste incinerated in 2021 and 2023, resulting in a slight decrease in emissions for the period 2020 through 2022.
- EIA (2024) published new data on the consumption of other petroleum liquids by U.S. Pacific Islands and Wake Island for years 2020 through 2022, resulting in a slight increase in emissions relative to the previous *Inventory*.

Overall, these changes resulted in an average annual decrease of less than 0.05 MMT CO_2 Eq. (less than 0.05 percent) in carbon emissions from non-energy uses of fossil fuels for the period 1990 through 2022, relative to the previous *Inventory*. This change was driven by slight increases in emissions for the period 2019 through 2021, and a decrease in emissions in 2022.

Planned Improvements

There are several future improvements planned:

- More accurate accounting of carbon in petrochemical feedstocks. EPA has worked with EIA to determine the cause of input/output discrepancies in the carbon 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 carbon 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 carbon input calculation in estimating emissions will be reconsidered. Alternative approaches that rely more substantially on the bottom-up carbon 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 carbon. Additional fates may be researched, including the fossil carbon 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 carbon content of solvents was researched, since the entire time series depends on one year's worth of solvent composition data. The data on carbon 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 carbon in solvents. Additional sources of solvents data will be investigated in order to update the carbon content assumptions.

- Updating the average carbon 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 carbon content for this category.
- Revising the methodology for consumption, production, and carbon content of plastics was researched; because of recent changes to the type of data publicly available for plastics, the NEU model for plastics applies data obtained from personal communications. Potential revisions to the plastics methodology to account for the recent changes in published data will be investigated.
- Although U.S.-specific storage factors have been developed for feedstocks, asphalt, lubricants, and waxes, default values from IPCC are still used for two of the non-energy fuel types (industrial coking coal, distillate oil), and broad assumptions are being used for miscellaneous products and other petroleum. Over the long term, there are plans to improve these storage factors by analyzing carbon 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.
- Assess the current method and/or identify new data sources (e.g., EIA) for estimating emissions from ammonia/fertilizer use of natural gas.

Investigate EIA NEU and MECS data to update, as needed, adjustments made for ammonia production and “natural gas to chemical plants, other uses” and “natural gas to other” non-energy uses, including iron and steel production, in energy uses and IPPU.

3.3 Incineration of Waste (Source Category 1A)

Combustion 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, combustion of MSW tends to occur at waste-to-energy facilities or industrial facilities where useful energy is recovered, and thus emissions from waste combustion 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. Combustion 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 combustion are calculated by estimating the quantity of waste combusted and the fraction of the waste that is carbon derived from fossil sources.

Most of the organic materials in MSW are of biogenic origin (e.g., paper, yard trimmings), and have their net carbon 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 combustion estimate, though waste disposal practices for tires differ from MSW. Estimates on emissions from hazardous waste combustion can be found in Annex 2.3 and are accounted for as part of the carbon mass balance for non-energy uses of fossil fuels.

Approximately 25.7 million metric tons of MSW were combusted in 2023 (EPA 2024). Carbon dioxide emissions from combustion of waste decreased 3.7 percent since 1990, to an estimated 12.4 MMT CO_2 (12,425 kt) in 2023. Emissions across the time series are shown in Table 3-28 and Table 3-29.

Waste combustion is also a source of CH_4 and N_2O emissions (De Soete 1993; IPCC 2006). Methane emissions from the combustion of waste were estimated to be less than 0.5 MMT CO_2 Eq. (less than 0.05 kt CH_4) in 2023 and have remained steady since 1990. Nitrous oxide emissions from the combustion of waste were estimated to be 0.3 MMT CO_2 Eq. (1.2 kt N_2O) in 2023 and have decreased by 19 percent since 1990. This decrease is driven by the decrease in total MSW combusted.

Table 3-28: CO_2, CH_4, and N_2O Emissions from the Combustion of Waste (MMT CO_2 Eq.)

Gas	1990	2005	2019	2020	2021	2022	2023
CO_2	12.9	13.3	12.9	12.9	12.5	12.5	12.4
CH_4	+	+	+	+	+	+	+
N_2O	0.4	0.3	0.4	0.3	0.4	0.3	0.3
Total	**13.3**	**13.6**	**13.3**	**13.3**	**12.8**	**12.8**	**12.8**

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

Table 3-29: CO_2, CH_4, and N_2O Emissions from the Combustion of Waste (kt)

Gas	1990	2005	2019	2020	2021	2022	2023
CO_2	12,900	13,254	12,948	12,921	12,476	12,484	12,425
CH_4	+	+	+	+	+	+	+
N_2O	2	1	1	1	1	1	1

+ Does not exceed 0.05 kt.

Methodology and Time-Series Consistency

Municipal Solid Waste Combustion

A Tier 2 approach is used to determine both CO_2 and non-CO_2 emissions from the combustion of waste, the method uses tonnage of waste combusted and an estimated country specific emissions factor. Emission estimates from the combustion of tires are discussed separately. Data for total waste combusted was derived from *BioCycle* (van Haaren et al. 2010), EPA Facts and Figures Report, Energy Recovery Council (ERC), EPA's Greenhouse Gas Reporting Program (GHGRP), and the U.S. Energy Information Administration (EIA). Multiple sources were used to ensure a complete, quality dataset, as each source encompasses a different timeframe.

EPA determined the MSW tonnages based on data availability and accuracy throughout the time series.

- 1990-2006: MSW combustion tonnages are from Biocycle combustion data. Tire combustion data from the U.S. Tire Manufacturers Association (USTMA) are removed to arrive at MSW combusted without tires.
- 2006-2010: MSW combustion tonnages are an average of Biocycle (with USTMA tire data tonnage removed), U.S. EPA Facts and Figures, EIA, and Energy Recovery Council data (with USTMA tire data tonnage removed).
- 2011-2023: MSW combustion tonnages are from EPA's GHGRP data.

Table 3-30 provides the estimated tons of MSW combusted including and excluding tires.

Table 3-30: Municipal Solid Waste Combusted (Short Tons)

	1990	2005	2019	2020	2021	2022	2023
Waste Combusted (excluding tires)	33,344,839	26,486,414	28,174,311	27,586,271	27,867,446	26,338,130	25,676,432
Waste Combusted (including tires)	33,766,239	28,631,054	29,821,141	29,106,686	29,261,446	27,808,130	27,222,432

Sources: BioCycle, EPA Facts and Figures, ERC, GHGRP, EIA, USTMA.

CO_2 Emissions from MSW Excluding Scrap Tires

Fossil CO_2 emission factors were calculated from EPA's GHGRP data for non-biogenic sources. Using GHGRP-reported emissions for CH_4 and N_2O and assumed emission factors, the tonnage of waste combusted, excluding tires, was derived. Methane and N_2O emissions and assumed emission factors were used to estimate the amount of MSW combusted in terms of energy content. The energy content of MSW combusted was then converted into tonnage based on assumed MSW heating value. Two estimates were generated (one for CH_4 and one for N_2O) and the two were averaged together. Dividing fossil CO_2 emissions from GHGRP FLIGHT data for MSW combustors by this estimated tonnage yielded an annual CO_2 emission factor. As this data was only available following 2011, all years prior use an average of the emission factors from 2011 through 2015. See Annex 3.7 for more detail on how MSW carbon factors were calculated.

Finally, CO_2 emissions were calculated by multiplying the annual tonnage estimates, excluding tires, by the calculated emissions factor. Calculated fossil CO_2 emission factors are shown in Table 3-31.

Table 3-31: Calculated Fossil CO_2 Content per Ton Waste Combusted (kg CO_2/Short Ton Combusted)

Year	1990	2005	2019	2020	2021	2022	2023
CO_2 Emission Factors	366	366	363	377	365	382	384

CO_2 Emissions from Scrap Tires

Scrap tires contain several types of synthetic rubber, carbon black, and synthetic fibers. Each type of synthetic rubber has a discrete carbon content, and carbon black is 100 percent C. For synthetic rubber and carbon black in scrap tires, information on average weight, disposal percentage, and total tires incinerated for energy was obtained biannually from U.S. Scrap Tire Management Summary for 2005 through 2023 data (USTMA 2024). Information about scrap tire composition was taken from the Rubber Manufacturers' Association internet site (USTMA 2012a). 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. The mass of combusted material is multiplied by its carbon content to calculate the total amount of carbon stored. More detail on the methodology for calculating emissions from each of these waste combustion sources is provided in Annex 3.7. Table 3-32 provides CO_2 emissions from combustion of waste tires.

Table 3-32: CO_2 Emissions from Combustion of Tires (MMT CO_2 Eq.)

Year	1990	2005	2019	2020	2021	2022	2023
Synthetic Rubber	0.3	1.6	1.2	1.1	1.0	1.2	1.2
C Black	0.4	2.0	1.5	1.4	1.3	1.4	1.4
Total	**0.7**	**3.6**	**2.7**	**2.5**	**2.3**	**2.6**	**2.6**

Note: Totals may not sum due to independent rounding.

Non-CO_2 Emissions

Combustion of waste also results in emissions of CH_4 and N_2O. These emissions were calculated by multiplying the total estimated mass of waste combusted, including tires, by the respective emission factors. The emission factors for CH_4 and N_2O emissions per quantity of MSW combusted are default emission factors for the default continuously-fed stoker unit MSW combustion technology type and were taken from IPCC (2006).

Uncertainty

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. Statistical analyses or expert judgments of uncertainty were not available directly from the information sources for most 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 reported CO_2 emissions; N_2O and CH_4 emissions factors, and tire synthetic rubber and black carbon contents. The highest levels of uncertainty surround the reported emissions from GHGRP; the lowest levels of uncertainty surround variables that were determined by quantitative measurements (e.g., combustion efficiency, carbon content of carbon black).

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-23. Waste incineration CO_2 emissions in 2023 were estimated to be between 10.3 and 15.0 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 17 percent below to 20 percent above the 2023 emission estimate of 12.4 MMT CO_2 Eq. Waste incineration CH_4 emissions in 2023 were estimated to be between less than 0.00005 and less than 0.0005 MMT CO_2 Eq. at a 95 percent confident level. This indicates a range of 102 percent below to 103 percent above the 2023 emission estimate of less than 0.0005 MMT CO_2 Eq. Also at a 95 percent confidence level, waste incineration N_2O emissions in 2023 were estimated to be between 0.2 and 0.9 MMT CO_2 Eq. This indicates a range of 53 percent below to 161 percent above the 2023 emission estimate of 0.3 MMT CO_2 Eq.

Table 3-33: Approach 2 Quantitative Uncertainty Estimates for CO_2 and N_2O from the Incineration of Waste (MMT CO_2 Eq. and Percent)

Source	Gas	2023 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	12.4	10.3	15.0	-17%	+20%
Incineration of Waste	CH_4	+	+	+	-102%	+103%
Incineration of Waste	N_2O	0.3	0.2	0.9	-53%	+161%

+ Does not exceed 0.05 MMT CO_2 Eq.

[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 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 specifically focused on the emission factor and activity data sources and methodology used for estimating emissions from combustion 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 current *Inventory*.

Planned Improvements

No planned improvements for waste combustion were identified.

3.4 Coal Mining (Source Category 1B1a)

Three types of coal mining-related activities release CH_4 and CO_2 to the atmosphere: underground mining, surface mining, and post-mining (i.e., coal-handling) activities. While surface coal mines account for the majority of U.S. coal production, underground coal mines contribute the largest share of fugitive CH_4 emissions (see Table 3-35 and Table 3-36) due to the higher CH_4 content of coal in the deeper underground coal seams. In 2023, 190 underground coal mines and 362 surface mines were operating in the United States (EIA 2024). In recent years, the total number of active coal mines in the United States has declined.

Table 3-34: Coal Production (kt)

Year	1990	2005	2019	2020	2021	2022	2023
Underground							
Number of Mines	1,683	586	226	196	174	185	190
Production	384,244	334,399	242,557	177,380	200,122	201,525	197,701
Surface							
Number of Mines	1,656	789	432	350	332	354	362
Production	546,808	691,447	397,750	307,944	323,142	336,990	326,340
Total							
Number of Mines	3,339	1,398	658	546	506	539	552
Production	931,052	1,025,846	640,307	485,324	523,264	538,515	524,041

Note: Totals may not sum due to independent rounding.

Fugitive CH_4 Emissions

Underground coal 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 2023 were estimated to be 1,623 kt (45.4 MMT CO_2 Eq.), a decline of approximately 58 percent since 1990 (see Table 3-35 and Table 3-36). In 2023, underground mines accounted for approximately 74 percent of total emissions, surface mines accounted for 13 percent, and post-mining activities accounted for 13 percent. In 2023, total CH_4 emissions from coal mining increased by approximately 4 percent relative to the previous year. Total coal production in 2023 decreased by 3 percent compared to 2022. This resulted in a decrease of 1 percent in CH_4 emissions from surface mining and post-mining activities in 2023. However, surface mining and post-mining activities have a lower impact on total CH_4 compared to underground mining (74 percent of total emissions in 2023). The number of operating underground mines increased in 2023 and the amount of CH_4 recovered and used in 2023 increased by 6 percent compared to 2022. In 2023, the amount of CH_4 from underground mining activities increased by 6 percent compared to 2022.

Table 3-35: CH_4 Emissions from Coal Mining (MMT CO_2 Eq.)

Activity	1990	2005	2019	2020	2021	2022	2023
Underground (UG) Mining	**83.1**	**46.7**	**38.5**	**35.2**	**32.9**	**31.5**	**33.4**
Liberated	90.6	66.9	56.6	53.7	52.3	56.1	59.4
Recovered & Used	(7.5)	(20.1)	(18.1)	(18.5)	(19.4)	(24.6)	(26.0)
Surface Mining	**12.0**	**13.3**	**7.2**	**5.4**	**5.7**	**6.0**	**5.9**
Post-Mining (UG)	**10.3**	**8.6**	**5.8**	**4.3**	**4.8**	**4.8**	**4.8**
Post-Mining (Surface)	**2.6**	**2.9**	**1.5**	**1.2**	**1.2**	**1.3**	**1.3**
Total	**108.1**	**71.5**	**53.0**	**46.2**	**44.7**	**43.6**	**45.4**

Notes: Parentheses in above emissions tables indicate negative values. Totals may not sum due to independent rounding.

Table 3-36: CH_4 Emissions from Coal Mining (kt)

Activity	1990	2005	2019	2020	2021	2022	2023
Underground (UG) Mining	**2,968**	**1,669**	**1,375**	**1,257**	**1,176**	**1,124**	**1,193**
Liberated	3,237	2,388	2,022	1,917	1,868	2,003	2,122
Recovered & Used	(269)	(719)	(646)	(660)	(692)	(880)	(928)
Surface Mining	**430**	**475**	**255**	**194**	**205**	**215**	**211**
Post-Mining (UG)	**368**	**306**	**206**	**155**	**170**	**173**	**172**
Post-Mining (Surface)	**93**	**103**	**55**	**42**	**44**	**47**	**46**
Total	**3,860**	**2,552**	**1,892**	**1,648**	**1,595**	**1,558**	**1,623**

Notes: Parentheses in above emissions tables indicate negative values. Totals may not sum due to independent rounding.

Methodology and Time-Series Consistency

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 coal production from both underground mines and surface mines) in accordance with methodological decisions trees in IPCC guidelines (Volume 2, Chapter 4, Figure 4.1.1 and 4.1.2) and available data (IPCC 2006). 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 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)[57] (Subpart FF, "Underground Coal Mines"), data provided by the U.S. Mine Safety and Health Administration (MSHA) (MSHA 2024), 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 2024).[58] 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.[59]

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

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57 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).

58 Underground coal mines report to EPA under Subpart FF of the GHGRP (40 CFR Part 98). In 2023, 58 underground coal mines reported to the program.

59 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.

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 2023 and all of these mines reported the CH_4 removed through these systems to EPA's GHGRP under Subpart FF (EPA 2024). 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. Eleven of the 19 mines with degasification systems had operational CH_4 recovery and use projects, including one mine with two recovery and use projects (see step 1.3 below).[60]

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 2023. Data from state gas well production databases were used to supplement GHGRP degasification data for the remaining 5 mines (DMME 2024; ERG 2024; GSA 2024; WVGES 2024).

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.[61] EPA's GHGRP does not require gas production from virgin coal seams (coalbed methane) to be reported by coal mines under Subpart FF.[62] 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 2023. For all of these mines, GHGRP data were supplemented with historical data from state gas well production databases (ERG 2024; GSA 2024), 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 2024).

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

Eleven mines had a total of 12 CH_4 recovery and use projects in place in 2023, including one mine that had two recovery and use projects. All of these projects involved degasification systems. Ten of these

60 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.

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

62 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.

mines sold the recovered CH_4 to a pipeline, including one that also used CH_4 to fuel a thermal coal dryer. One mine destroyed the recovered CH_4 using enclosed flares.

The CH_4 recovered and used (or destroyed) at the 11 mines described above are estimated using the following methods:

- EPA's GHGRP data was exclusively used to estimate the CH_4 recovered and used from six of the 11 mines that deployed degasification systems in 2023. Based on quarterly 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 supplement GHGRP data to estimate CH_4 recovered and used from five mines that deployed degasification systems in 2023 (DMME 2024, ERG 2024, GSA 2024, and WVGES 2024). 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 location and timing of mined-through pre-mining wells.

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 2024) 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).

Fugitive CO_2 Emissions

Methane and CO_2 are naturally occurring in coal seams and are collectively referred to as coal seam gas. These gases remain trapped in the coal seam until coal is mined (i.e., coal seam is exposed and fractured during mining operations). Fugitive CO_2 emissions occur during underground coal mining, surface coal mining, and post-mining activities. Methods and data to estimate fugitive CO_2 emissions from underground and surface coal mining are presented in the sections below. Fugitive CO_2 emissions from post-mining activities were not estimated due to the lack of an IPCC method and unavailability of data.

Total fugitive CO_2 emissions in 2023 were estimated to be 2,404 kt (2.4 MMT CO_2 Eq.), a decline of approximately 48 percent since 1990. In 2023, underground mines accounted for approximately 89 percent of total fugitive CO_2 emissions. In 2023, total fugitive CO_2 emissions from coal mining decreased by approximately 3 percent relative to the previous year. This decrease was due to a decrease in annual coal production.

Table 3-37: CO_2 Emissions from Coal Mining (MMT CO_2 Eq.)

Activity	1990	2005	2019	2020	2021	2022	2023
Underground (UG) Mining	**4.2**	**3.6**	**2.7**	**1.9**	**2.2**	**2.2**	**2.1**
Liberated	4.2	3.6	2.6	1.9	2.2	2.2	2.1
Recovered & Used	(+)	(+)	(+)	(+)	(+)	(+)	(+)
Flaring	NO	NO	0.1	+	+	+	+
Surface Mining	**0.4**	**0.6**	**0.3**	**0.2**	**0.3**	**0.3**	**0.3**
Total	**4.6**	**4.2**	**3.0**	**2.2**	**2.5**	**2.5**	**2.4**

+ Does not exceed 0.05 MMT CO_2 Eq.
NO (Not Occurring)
Notes: Parentheses indicate negative values. Totals may not sum due to independent rounding.

Table 3-38: CO_2 Emissions from Coal Mining (kt)

Activity	1990	2005	2019	2020	2021	2022	2023
Underground (UG) Mining	**4,164**	**3,610**	**2,670**	**1,948**	**2,193**	**2,201**	**2,140**
Liberated	4,171	3,630	2,633	1,926	2,173	2,188	2,146
Recovered & Used	(8)	(21)	(18)	(19)	(19)	(25)	(26)
Flaring	NO	NO	55	41	40	38	20
Surface Mining	**443**	**560**	**322**	**249**	**262**	**273**	**264**
Total	**4,606**	**4,169**	**2,992**	**2,197**	**2,455**	**2,474**	**2,404**

NO (Not Occurring)
Notes: Parentheses indicate negative values. Totals may not sum due to independent rounding.

Methodology and Time-Series Consistency

EPA uses an IPCC Tier 1 method for estimating fugitive CO_2 emissions from underground coal mining and surface mining in accordance with methodological decisions trees in IPCC guidelines (Volume 2, Chapter 4, Figure 4.1.1a) and available data (IPCC 2019). IPCC methods and data to estimate fugitive CO_2 emissions from post-mining activities (for both underground and surface coal mining) are currently not available.

Step 1: Underground Mining

EPA used the following overarching IPCC equation to estimate fugitive CO_2 emissions from underground coal mines (IPCC 2019):

Equation 3-1: Estimating Fugitive CO_2 Emissions from Underground Mines

$$\begin{aligned} &Total\ CO_2\ from\ Underground\ Mines \\ &\qquad = CO_2\ from\ underground\ mining - Amount\ of\ CO_2\ in\ gas\ recovered \\ &\qquad + CO_2\ from\ methane\ flaring \end{aligned}$$

Step 1.1: Estimate Fugitive CO_2 Emissions from Underground Mining

EPA estimated fugitive CO_2 emissions from underground mining using the IPCC Tier 1 emission factor (5.9 m^3/metric ton) and annual coal production from underground mines (EIA 2024). The underground mining default emission factor accounts for all the fugitive CO_2 likely to be emitted from underground coal mining. Therefore, the amount of CO_2 from coal seam gas recovered and utilized for energy is subtracted from underground mining estimates in Step 2, below. Under IPCC methods, the CO_2 emissions from gas recovered and utilized for energy use (e.g., injected into a natural gas pipeline) are reported under other sectors of the *Inventory* (e.g., stationary combustion of fossil fuel or oil and natural gas systems) and not under the coal mining sector.

Step 1.2: Estimate Amount of CO_2 In Coal Seam Gas Recovered for Energy Purposes

EPA estimated fugitive CO_2 emissions from coal seam gas recovered and utilized for energy purposes by using the IPCC Tier 1 default emission factor (19.57 metric tons CO_2/million cubic meters of coal bed methane (CBM) produced) and quantity of coal seam gas recovered and utilized. Data on annual quantity of coal seam gas recovered and utilized are available from GHGRP and state sales data (EPA 2024; DMME 2024; ERG 2024; GSA 2024; WVGES 2024). The quantity of coal seam gas recovered and destroyed without energy recovery (e.g., flaring) is deducted from the total coal seam gas recovered quantity (EPA 2024).

Step 1.3: Estimate Fugitive CO_2 Emissions from Flaring

The IPCC method includes combustion CO_2 emissions from gas recovered for non-energy uses (i.e., flaring, or catalytic oxidation) under fugitive CO_2 emission estimates for underground coal mining. In effect, these emissions, though occurring through stationary combustion, are categorized as fugitive emissions in the *Inventory*. EPA estimated CO_2 emissions from methane flaring using the following equation:

Equation 3-2: Estimating CO_2 Emissions from Drained Methane Flared or Catalytically Oxidized

$$\begin{aligned} CO_2\ from\ flaring \\ &= 0.98\ \times Volume\ of\ methane\ flared \times Conversion\ Factor \\ &\times Stoichiometric\ Mass\ Factor \end{aligned}$$

In 2023, there was a single mine that reported destruction of recovered methane through flaring without energy use. Annual data for 2023 for this mine were obtained from the GHGRP (EPA 2024).

Step 2: Surface Mining

EPA estimated fugitive CO_2 emissions from surface mining using the IPCC Tier 1 emission factor (0.44 m^3/metric ton) and annual coal production from surface mines (EIA 2024).

Uncertainty

A quantitative uncertainty analysis was conducted for the coal mining source category using the IPCC-recommended Approach 2 uncertainty estimation methodology. Because emission estimates of CH_4 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 state 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 coal mining, as a general matter, results in significantly larger CH_4 emissions due to production of higher-rank coal and greater depth, and estimated emissions from underground mining constitute the majority of estimated total coal mining CH_4 emissions, the uncertainty associated with underground emissions is the primary factor that determines overall uncertainty.

The major sources of uncertainty for estimates of fugitive CO_2 emissions are the Tier 1 IPCC default emission factors used for underground mining (-50 percent to +100 percent) and surface mining (-67 percent to +200 percent) (IPCC 2019). Additional sources of uncertainty for fugitive CO_2 emission estimates include EIA's annual coal production data and data used for gas recovery projects, such as GHGRP data, state gas sales data, and VAM estimates for the single mine that operates an active VAM project. Uncertainty ranges for these additional data sources are already available, as these are the same data sources used for CH_4 emission estimates.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-39. Coal mining CH_4 emissions in 2023 were estimated to be between 40.7 and 55.2 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 10 percent below to 21 percent above the 2023 emission estimate of 45.4 MMT CO_2 Eq. Coal mining fugitive CO_2 emissions in 2023 were estimated to be between 0.8 and 4.2 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 68 percent below to 76 percent above the 2023 emission estimate of 2.4 MMT CO_2 Eq.

Table 3-39: Approach 2 Quantitative Uncertainty Estimates for CH_4 and CO_2 Emissions from Coal Mining (MMT CO_2 Eq. and Percent)

Source	Gas	2023 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	45.4	40.7	55.2	-10%	+21%
Coal Mining	CO_2	2.4	0.8	4.2	-68%	+76%

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

QA/QC and Verification

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. 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. No QA/QC issues or errors were identified in the 2023 Subpart FF data.

Recalculations Discussion

Time series recalculations were performed due to revised historical data from state natural gas sales databases for three mines, which are used to estimate avoided CH_4 emissions from CH_4 recovered and used. As a result of recalculations, CH_4 emissions decreased by an average of less than 0.001 percent across the time series, compared to the previous *Inventory*. The biggest increase in CH_4 emissions was in 1991 where emissions increased by 0.004 percent, compared to the previous *Inventory*. The biggest decrease in CH_4 emissions was in 2011 (less than 0.001 percent). As a result of recalculations, there was a very minor increase in CH_4 emissions in 2022 (less than 0.001 percent), compared to the previous *Inventory*.

Planned Improvements

EPA is assessing planned improvements for future reports, but currently has no specific planned improvements for estimating CH_4 and CO_2 emissions from underground and surface mining and CH_4 emissions from post-mining.

3.5 Abandoned Underground Coal Mines (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 8.1 to 12.1 MMT CO_2 Eq. from 1990 to 2023, 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 (12.1 MMT CO_2 Eq.) due to the large number of gassy mine[63] closures from 1994 to 1996 (70 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 2023 there was one gassy mine closure. Gross abandoned mine emissions decreased slightly from 9.1 MMT CO_2 Eq. (324 kt CH_4) in 2022 to 9.0 (323 kt CH_4) MMT CO_2 Eq. in 2023 (see Table 3-40 and Table 3-41). Gross emissions are reduced by CH_4 recovered and used at 62 mines, resulting in net emissions in 2023 of 6.1 MMT CO_2 Eq. (219 kt CH_4).

Table 3-40: CH_4 Emissions from Abandoned Coal Mines (MMT CO_2 Eq.)

Activity	1990	2005	2019	2020	2021	2022	2023
Abandoned Underground Mines	8.1	9.3	9.6	9.4	9.2	9.1	9.0
Recovered & Used	NO	(2.0)	(2.9)	(2.9)	(3.0)	(3.0)	(2.9)
Total	**8.1**	**7.4**	**6.6**	**6.5**	**6.2**	**6.1**	**6.1**

NO (Not Occurring)
Notes: Parentheses indicate negative values. Totals may not sum due to independent rounding.

Table 3-41: CH_4 Emissions from Abandoned Coal Mines (kt)

Activity	1990	2005	2019	2020	2021	2022	2023
Abandoned Underground Mines	288	334	341	335	330	324	323
Recovered & Used	NO	(70)	(104)	(103)	(109)	(106)	(104)
Total	**288**	**264**	**237**	**232**	**221**	**218**	**219**

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

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

Methodology and Time-Series Consistency

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 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.

There are sufficient mine level data available to establish decline curves for individual gassy mines abandoned since 1972. For mines abandoned prior to 1972, county level data are available. Mine status information (i.e., whether a mine is sealed, venting, or flooded) is not available for all the abandoned gassy mines. Therefore, a hybrid Tier 2/Tier 3 method was developed to model abandoned gassy mine emissions using Monte Carlo simulations. Tier 3 calculations are used for mines with known status information where decline curves can be used to directly estimate abandoned mine emissions. For mines with unknown status, a Tier 2 approach that estimates basin level emissions is used. This Tier 2 approach relies on data from other mines with known status and located within the same basin as the unknown status mines. This approach is consistent with the IPCC 2006 Guidelines as underground mines can be considered point sources and measurement methods are available.

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:

Equation 3-3: Decline Function to Estimate Venting Abandoned Mine Methane Emissions

$$q = q_i \left(1 + bD_i t\right)^{\left(-\frac{1}{b}\right)}$$

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:

Equation 3-4: Decline Function to Estimate Flooded Abandoned Mine Methane Emissions

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

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 532 abandoned mines closed since 1972 produced CH_4 emissions greater than 100 Mcfd when active. Further, the status of 308 of the 532 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 3-42 presents the count of mines by post-abandonment state, based on EPA's probability distribution analysis.

Table 3-42: Number of Gassy Abandoned Mines Present in U.S. Basins in 2023, Grouped by Class According to Post-Abandonment State

Basin	Sealed	Vented	Flooded	Total Known	Unknown	Total Mines
Central Appl.	43	25	50	118	145	263
Illinois	35	3	14	52	31	83
Northern Appl.	50	23	15	88	38	126
Warrior Basin	0	0	16	16	0	16
Western Basins	28	4	2	34	10	44
Total	**156**	**55**	**97**	**308**	**224**	**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 United States, representing 78 percent of the emissions. State-specific, initial emission rates were used based on average coal mine CH_4 emission 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 2023). 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. Methane 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 2023. 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, respectively, to account for all U.S. abandoned mine emissions.

From 1993 through 2023, emission totals were downwardly adjusted to reflect CH_4 emissions avoided from abandoned mines with CH_4 recovery and use or destruction systems. Currently, there are 62 abandoned mines with recovery projects, including 11 projects at mines abandoned before 1972 (pre-1972 mines) (EPA 2004, CMOP 2024). Because CH_4 recovered by these projects is expected to decline with the age of the mine, CH_4 recovery is assumed to be the total estimated CH_4 liberated based on the mine's decline function except for three recovery projects where additional data are available (COGIS 2018, MSHA 2024).[64]

The *Inventory* totals were not adjusted for abandoned mine CH_4 emissions avoided from 1990 through 1992 due to unavailability of data. Avoided CH_4 emissions from pre-1972 abandoned mines are estimated by multiplying the total estimated emissions from these mines in each decade by the fraction of mines with recovery projects in that decade. For recovery projects at pre-1972 abandoned mines, four projects are at mines abandoned in the 1920s, three in the 1930s, two in the 1950s, and two in the 1960s (EPA 2004).

Reviewing Coalbed Methane Outreach Program data (CMOP 2024) revealed five additional recovery projects starting in 2021 that were added to the recovery project list. In addition to reviewing CMOP data, the recovery project list was checked against the Global Methane Initiative International Coal Mine Methane Project List Database (GMI) and the American Carbon Registry (ACR) (GMI 2024, ACR 2024). Of the 44 operational recovery projects for U.S. abandoned coal mines currently available in the GMI dataset, 35 are already included in the AMM model. Three new projects from this dataset were added to the recovery list (one project contains three mines). The remaining projects in the GMI dataset are for mines that are not yet abandoned according to MSHA records or were in abandoned in 2024 and will be included in next year's Inventory (MSHA 2024). The ACR Registry had one additional recovery project not listed in the other datasets that was added to the AMM model (ACR 2024).

Uncertainty

A quantitative uncertainty analysis was conducted for the abandoned coal mine source category using the IPCC-recommended Approach 2 uncertainty estimation methodology. 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 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 3-43. Annual abandoned coal mine CH_4 emissions in 2023 were estimated to be between 4.9 and 7.6 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 20 percent below to 24 percent above the 2023 emission estimate of 6.1 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 at the time of abandonment exist.

[64] Data from a state oil and gas database (COGIS) is used for one project and the mine status information from MSHA for two mines (sealed and flooded) indicate zero recovery emissions for these projects.

Table 3-43: Approach 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Abandoned Underground Coal Mines (MMT CO_2 Eq. and Percent)

Source	Gas	2023 Emission Estimate (MMT CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a]			
			(MMT CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Abandoned Underground Coal Mines	CH_4	6.1	4.9	7.6	-20%	+24%

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

QA/QC and Verification

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. Trends across the time series were analyzed to determine whether any corrective actions were needed.

Recalculations Discussion

Eleven new abandoned mine methane recovery projects were added to the AMM model during the current *Inventory* (CMOP 2024, GMI 2024, ACR 2024). CMOP, GMI, and ACR data indicate 10 of these recovery projects were started in 2021 and one in 2022. Time series recalculations were performed for 2021 and 2022 by adding in the recovery project(s) and rerunning the 2021 and 2022 AMM models. As a result of recalculations, CH_4 emissions decreased by one percent in 2021 and three percent in 2022, compared to the previous *Inventory*.

3.6 Petroleum Systems (Source Category 1B2a)

This category (1B2a) is defined in the IPCC methodological guidance as fugitive emissions from petroleum systems, which per IPCC guidelines include emissions from leaks, venting, and flaring. Methane emissions from petroleum systems are primarily associated with onshore and offshore crude oil exploration, 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 3.1). Emissions of N_2O from petroleum systems are primarily associated with flaring.

Total greenhouse gas emissions (CH_4, CO_2, and N_2O) from petroleum systems in 2023 were 61.3 MMT CO_2 Eq., an increase of 3 percent from 1990, primarily due to increases in CO_2 emissions. Total emissions decreased by 7 percent from 2010 levels and have increased by 5 percent since 2022. Total CO_2 emissions from petroleum systems in 2023 were 23.3 MMT CO_2 (23,272 kt CO_2), 2.4 times higher than in 1990. Total CO_2 emissions in 2023 were 1.7 times higher than in 2010 and 5 percent higher than in 2022. Total CH_4 emissions from petroleum systems in 2023 were 38.0 MMT CO_2 Eq. (1,358 kt CH_4), a decrease of 24 percent from 1990. Since 2010, total CH_4 emissions decreased by 27 percent; and since 2022, CH_4 emissions increased by 5 percent. Total N_2O emissions from petroleum systems in 2023 were 0.022 MMT CO_2 Eq. (0.083 kt N_2O), 1.6 times higher than in 1990, 1.2 times higher than in 2010, and 54 percent lower than in 2022. Since 1990, U.S. oil production has increased by 69 percent. In 2023, U.S. oil production was 186 percent higher than in 2010 and 8 percent higher than in 2022.

Each year, some estimates in the *Inventory* are recalculated with improved methods and/or data. These improvements are implemented consistently across the entire *Inventory's* time series (i.e., 1990 to 2023) to ensure that the trend is representative of changes in emissions levels. Recalculations in petroleum systems in this year's *Inventory* include:

- Updates to oil and gas well counts, oil and gas production volumes, and produced water production volumes using the most recent data from Enverus.
- Updates to oil and gas production volumes using the most recent data from the United States Energy Information Administration (EIA).
- Recalculations due to Greenhouse Gas Reporting Program (GHGRP) submission revisions.
- Methodological updates for offshore production in the Gulf of America.

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

Exploration. Exploration includes well drilling, testing, and completions. Exploration accounts for less than 0.5 percent of total CH_4 emissions (including leaks, vents, and flaring) from petroleum systems in 2023. 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 95 percent, and while the number of hydraulically fractured wells completed increased 64 percent, there were decreases in the fraction of such completions without reduced emissions completions (RECs) or flaring. Emissions of CH_4 from exploration were highest in 2008, over 62 times higher than in 2023; and lowest in 2022. Emissions of CH_4 from exploration increased 10 percent from 2022 to 2023, due to an increase in emissions from hydraulically fractured oil well completions without RECs. Exploration accounts for 2 percent of total CO_2 emissions (including leaks, vents, and flaring) from petroleum systems in 2023. Emissions of CO_2 from exploration in 2023 were 21 percent higher than in 1990, and increased by 50 percent from 2022, largely due to an increase in emissions from hydraulically fractured oil well completions with REC and flaring (by 78 percent from 2022). Emissions of CO_2 from exploration were highest in 2014, over 8 times higher than in 2023. Exploration accounts for 1 percent of total N_2O emissions from petroleum systems in 2023. Emissions of N_2O from exploration in 2023 are 22 percent higher than in 1990, and 59 percent higher than in 2022, due to hydraulically fractured oil well completions with flaring.

Production. Production accounts for 97 percent of total CH_4 emissions (including leaks, vents, and flaring) from petroleum systems in 2023. The predominant sources of emissions from production field operations are pneumatic controllers, equipment leaks, offshore oil platforms, produced water, gas engines, chemical injection pumps, and associated gas flaring. In 2023, these seven sources together accounted for 91 percent of the CH_4 emissions from production. Since 1990, CH_4 emissions from production have decreased by 20 percent primarily due to decreases in emissions from offshore production. Overall, production segment CH_4 emissions increased by 5 percent from 2022 levels due primarily to equipment leaks. Production emissions account for 86 percent of the total CO_2 emissions (including leaks, vents, and flaring) from petroleum systems in 2023. The principal sources of CO_2 emissions are associated gas flaring, miscellaneous production flaring, and oil tanks with flares. In 2023, these three sources together accounted for 97 percent of the CO_2 emissions from production. In 2023, CO_2 emissions from production were 3.3 times higher than in 1990, due to increases in flaring emissions from associated gas flaring, miscellaneous production flaring, and tanks. Overall, in 2023, production segment CO_2 emissions increased by 5 percent from 2022 levels primarily due to increases in miscellaneous production flaring in the Permian Basin. Production emissions accounted for 65 percent of the total N_2O emissions from petroleum systems in 2023. The principal sources of N_2O emissions are oil tanks with flares, associated gas flaring, and miscellaneous production flaring, accounting for 83 percent of N_2O emissions from the production segment in 2023. In 2023, N_2O emissions from production were 2.2 times higher than in 1990 and were 65 percent lower than in 2022.

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. Crude oil transportation activities account for 0.7 percent of total CH_4 emissions from petroleum systems. Emissions from tanks, marine loading, and truck loading operations accounted for 81 percent of CH_4 emissions from crude oil transportation in 2023. Since 1990, CH_4 emissions from transportation have increased by 37 percent. In 2023, CH_4 emissions from transportation increased by 6 percent from 2022 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 81 percent of CO_2 emissions from crude oil transportation.

Crude Oil Refining. Crude oil refining processes and systems account for 2 percent of total CH_4 emissions from petroleum systems in 2023. 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 a negligible amount of CH_4 in all refined products. Within refineries, flaring accounts for 45 percent of the CH_4 emissions, while delayed cokers, uncontrolled blowdowns, and equipment leaks account for 17, 13 and 11 percent, respectively. CH_4 emissions from refining of crude oil have decreased by 12 percent since 1990, and decreased by 4 percent from 2022; 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 12 percent of total CO_2 emissions from petroleum systems. Of the total CO_2 emissions from refining, almost all (about 99 percent) of it comes from flaring.[65] Since 1990, refinery CO_2 emissions decreased by 10 percent and have increased by 1 percent from 2022 levels, due to changes in flaring emissions. Flaring occurring at crude oil refining processes and systems accounts for 34 percent of total N_2O emissions from petroleum systems. In 2023, refinery N_2O emissions increased by 3 percent since 1990 and increased by 1 percent from 2022 levels.

Table 3-44: Total Greenhouse Gas Emissions (CO_2, CH_4, and N_2O) from Petroleum Systems (MMT CO_2 Eq.)

Activity	1990	2005	2019	2020	2021	2022	2023
Exploration	3.4	5.8	2.5	1.1	0.8	0.4	0.6
Production	52.2	48.3	89.0	74.5	64.5	54.2	56.9
Transportation	0.2	0.1	0.3	0.2	0.2	0.2	0.3

65 Petroleum systems includes emissions from 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.

Activity	1990	2005	2019	2020	2021	2022	2023
Crude Refining	3.9	4.5	4.4	3.6	3.7	3.5	3.5
Total	**59.6**	**58.7**	**96.2**	**79.5**	**69.2**	**58.4**	**61.3**

Note: Totals may not sum due to independent rounding.

Table 3-45: CH_4 Emissions from Petroleum Systems (MMT CO_2 Eq.)

Activity	1990	2005	2019	2020	2021	2022	2023
Exploration	3.0	5.3	0.5	0.3	0.2	0.1	0.1
Production	46.1	42.2	49.2	49.3	44.0	35.2	37.0
Pneumatic Controllers	21.3	22.8	24.3	30.8	27.1	18.5	16.3
Offshore Production	10.5	7.3	4.3	3.0	2.9	2.9	2.9
Equipment Leaks	2.3	2.8	3.9	3.2	3.2	3.1	6.7
Gas Engines	2.3	2.0	2.6	2.5	2.5	2.5	2.5
Produced Water	2.6	1.8	2.8	2.5	2.3	2.4	2.5
Chemical Injection Pumps	1.3	2.2	3.3	2.6	2.3	2.1	1.8
Assoc Gas Flaring	0.6	0.4	2.5	1.3	1.0	0.8	0.9
Other Sources	5.3	2.8	5.4	3.4	2.8	2.8	3.3
Crude Oil Transportation	**0.2**	**0.1**	**0.3**	**0.2**	**0.2**	**0.2**	**0.3**
Refining	**0.7**	**0.9**	**0.9**	**0.7**	**0.7**	**0.7**	**0.7**
Total	**50.0**	**48.4**	**50.8**	**50.6**	**45.1**	**36.3**	**38.0**

Note: Totals may not sum due to independent rounding.

Table 3-46: CH_4 Emissions from Petroleum Systems (kt CH_4)

Activity	1990	2005	2019	2020	2021	2022	2023
Exploration	**106**	**189**	**16**	**12**	**7**	**4**	**5**
Production	**1,648**	**1,505**	**1,756**	**1,762**	**1,571**	**1,258**	**1,321**
Pneumatic Controllers	761	814	868	1,099	967	662	581
Offshore Production	374	261	155	108	104	104	104
Equipment Leaks	82	101	139	113	113	112	239
Gas Engines	81	70	93	89	88	89	90
Produced Water	92	64	100	91	81	85	90
Chemical Injection Pumps	47	80	118	93	83	76	64
Assoc Gas Flaring	20	15	91	47	35	30	34
Other Sources	189	100	193	122	101	100	119
Crude Oil Transportation	**7**	**5**	**9**	**8**	**8**	**8**	**9**
Refining	**27**	**30**	**31**	**26**	**25**	**25**	**24**
Total	**1,787**	**1,730**	**1,813**	**1,807**	**1,611**	**1,295**	**1,358**

Note: Totals may not sum due to independent rounding.

Table 3-47: CO_2 Emissions from Petroleum Systems (MMT CO_2)

Activity	1990	2005	2019	2020	2021	2022	2023
Exploration	0.4	0.5	2.1	0.8	0.6	0.3	0.5
Production	6.0	6.2	39.8	25.2	20.5	18.9	19.9
Transportation	+	+	+	+	+	+	+
Crude Refining	3.2	3.6	3.6	2.9	3.0	2.8	2.9

Activity	1990	2005	2019	2020	2021	2022	2023
Total	**9.6**	**10.2**	**45.4**	**28.9**	**24.1**	**22.1**	**23.3**

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

Table 3-48: CO_2 Emissions from Petroleum Systems (kt CO_2)

Activity	1990	2005	2019	2020	2021	2022	2023
Exploration	398	465	2,053	798	602	321	481
Production	6,024	6,153	39,830	25,203	20,487	18,941	19,928
Transportation	0.9	0.7	1.3	1.2	1.1	1.2	1.3
Crude Refining	3,174	3,602	3,560	2,874	3,001	2,820	2,862
Total	**9,597**	**10,222**	**45,445**	**28,876**	**24,091**	**22,084**	**23,272**

Note: Totals may not sum due to independent rounding.

Table 3-49: N_2O Emissions from Petroleum Systems (Metric Tons CO_2 Eq.)

Activity	1990	2005	2019	2020	2021	2022	2023
Exploration	181	209	822	353	290	138	220
Production	6,635	6,168	22,120	13,875	11,977	40,649	14,330
Transportation	NE	NE	NE	NE	NE	NE	NE
Crude Refining	7,262	8,243	9,283	7,523	7,867	7,387	7,496
Total	**14,078**	**14,621**	**32,225**	**21,751**	**20,134**	**48,174**	**22,046**

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

Table 3-50: N_2O Emissions from Petroleum Systems (Metric Tons N_2O)

Activity	1990	2005	2019	2020	2021	2022	2023
Exploration	0.7	0.8	3.1	1.3	1.1	0.5	0.8
Production	25.0	23.3	83.5	52.4	45.2	153.4	54.1
Transportation	NE	NE	NE	NE	NE	NE	NE
Crude Refining	27.4	31.1	35.0	28.4	29.7	27.9	28.3
Total	**53.1**	**55.2**	**121.6**	**82.1**	**76.0**	**181.8**	**83.2**

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

Methodology and Time-Series Consistency

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 using an IPCC Tier 3 approach (i.e., all refineries in the nation report facility-level emissions data to the GHGRP, which are included directly in the national emissions estimates here). Other estimates are developed with a Tier 2 approach. Tier 1 approaches are not used.

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 2024).

Emission factors for hydraulically fractured (HF) oil well completions and workovers (in four control categories) were developed at the basin level using EPA's GHGRP data; year-specific data were used to calculate basin-specific emission factors from 2016-forward and the year 2016 emission factors were applied to all prior years in the time series. For basins not reporting to the GHGRP, Subpart W average emission factors were used. For more information, please see the 2023 memoranda available online.[66]

The emission factors for 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.[67] For offshore oil production, emission factors were calculated using BOEM data for offshore facilities in federal waters of the Gulf of America (and these data were also applied to facilities located in state waters of the Gulf of America) 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 2023, 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 pneumatic controllers and tanks, basin-specific emission factors were calculated for all the basins reporting to the GHGRP. These emission factors were calculated for all the years with applicable GHGRP data (i.e., 2011 - 2023 or 2015 - 2023). For the remaining basins (i.e., basins not reporting to the GHGRP), Subpart W average emission factors were used. For more information, please see memoranda available online.

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,

66 See https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems.

67 See https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems.

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 America 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.

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 2025), 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 2024).

For HF oil well completions and workovers, pneumatic controllers, equipment leaks, chemical injection pumps, and tanks, basin-specific activity factors were calculated for all the basins reporting to the GHGRP. These factors were calculated for all the years with applicable GHGRP data (i.e., 2011 through 2023, 2016 through 2023, or 2015 through 2023). For the remaining basins (i.e., basins not reporting to the GHGRP), GHGRP average activity factors were used. For more information, please see memoranda available online.[68]

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

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 notation key "IE" is used for CO_2 and CH_4 emissions from venting and flaring in common data tables category 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).

As noted above, 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 and Time-Series Consistency discussion above and Annex 3.5.

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990 through 2023.

Uncertainty

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 memoranda *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2016: Natural Gas and Petroleum Systems Uncertainty Estimates* (*2018 Uncertainty memo)* and *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2019: Update for Natural Gas and Petroleum Systems CO_2 Uncertainty Estimates (2021 Uncertainty memo)*.[69]

EPA used Palisade's @RISK add-in tool for Microsoft Excel to estimate the 95 percent confidence bound around CH_4 and CO_2 emissions from petroleum systems for the current *Inventory*. For the CH_4 uncertainty analysis, EPA focused on the three highest methane-emitting sources for the year 2023, which together emitted 51 percent of methane from petroleum systems in 2023, and extrapolated the estimated uncertainty for the remaining sources. For the CO_2 uncertainty analysis, EPA focused on the four highest-emitting sources for the year 2023 which together emitted 52 percent of CO_2 from

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

petroleum systems in 2023, and extrapolated the estimated uncertainty for the remaining sources. The @RISK add-in provides for the specification of probability density functions (PDFs) for key variables within a computational structure that mirrors the calculation of the inventory estimate. For emission factors that are derived from methane emissions measurement studies, the PDFs are commonly determined to be lognormally distributed (GRI/EPA 1996; EPA 1999). For activity data that are derived from national datasets, the PDFs are set to a uniform distribution (see 2018 and 2021 Uncertainty memos). Many emission factors and activity factors are calculated using subpart W data, and for these, the @RISK add-in determines the best fitting PDF (e.g., lognormal, gaussian), based on bootstrapping of the underlying data (see 2018 and 2021 Uncertainty memos). The IPCC guidance notes that in using this Approach 2 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. To estimate uncertainty for N_2O, EPA applied the uncertainty bounds calculated for CO_2. EPA will seek to refine this estimate in future *Inventories*.

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 2023, using the recommended IPCC methodology. The results of the Approach 2 uncertainty analysis are summarized in Table 3-51. Petroleum systems CH_4 emissions in 2023 were estimated to be between 33.1 and 47.2 MMT CO_2 Eq., while CO_2 emissions were estimated to be between 19.0 and 28.5 MMT CO_2 Eq. at a 95 percent confidence level. Petroleum systems N_2O emissions in 2023 were estimated to be between 0.018 and 0.027 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 3-51: Approach 2 Quantitative Uncertainty Estimates for CH_4 and CO_2 Emissions from Petroleum Systems (MMT CO_2 Eq. and Percent)

Source	Gas	2023 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	38.0	33.1	47.2	-13%	+24%
Petroleum Systems	CO_2	23.3	19.0	28.5	-18%	+22%
Petroleum Systems	N_2O	0.022	0.018	0.027	-18%	+22%

[a] Range of emission estimates estimated by applying the 95 percent confidence intervals obtained from the Monte Carlo

Simulation analysis conducted for the year 2023 CH_4 and 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.

QA/QC and Verification Discussion

In order to ensure the quality of the emission estimates for petroleum systems, general (IPCC Tier 1) Quality Assurance/Quality Control (QA/QC) procedures were implemented consistent with the U.S. Inventory QA/QC plan outlined in Annex 8.

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 emission 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.[70]

As in previous years, EPA conducted early engagement and communication with stakeholders on updates prior to public review of the current *Inventory*. EPA held a stakeholder webinar on BOEM offshore data updates and greenhouse gas data for oil and gas in November of 2024. EPA released memos detailing updates under consideration and requesting stakeholder feedback. EPA then released a final memorandum documenting the methodology implemented in the current Inventory.In recent years, several studies have measured emissions at the source level and at the national or regional level and calculated emission estimates that may differ from the *Inventory*. There are a variety of potential uses of data from new studies, including replacing a previous estimate or factor, verifying or QA of an existing estimate or factor, and identifying areas for updates. In general, there are two major types of studies related to oil and gas greenhouse gas data: studies that focus on measurement or quantification of emissions from specific activities, processes, and equipment, and studies that use tools such as inverse modeling to estimate the level of overall emissions needed to account for measured atmospheric concentrations of greenhouse gases at various scales. The first type of study can lead to direct improvements to or verification of *Inventory* estimates. In the past few years, EPA has reviewed, and in many cases, incorporated data from these data sources. The second type of study can provide general indications on potential over- and under-estimates.

A key challenge in using these types of studies to assess *Inventory* results is having a relevant basis for comparison (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 spatial and temporal scales, EPA has 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

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

error characterization.[71] The most recent version of the gridded methane inventory is designed to be consistent with the U.S. EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2018* estimates for the years 2012 through 2018. The gridded inventory improves efforts to compare results of this *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. Based on the review of the most recent GHGRP data, EPA did not identify any additional refineries that would require gap filling. There are a total of 6 refineries that EPA previously identified (i.e., during the 1990 through 2022 *Inventory* and prior versions) as not reporting to the GHGRP and continued to gap fill annual emissions for these refineries. EPA used the last reported emissions (by source) for these refineries as proxy to gap fill annual emissions.

Recalculations Discussion

EPA received information and data related to the emission estimates through GHGRP reporting and presented information to stakeholders regarding the updates under consideration. In December 2024, EPA released a draft memorandum that discussed changes under consideration and requested stakeholder feedback on those changes. EPA then released a final memorandum documenting the methodology implemented in the current *Inventory*.[72] The memorandum cited in the Recalculations Discussion below is: *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2023: Updates to Use New Offshore Data* (*Offshore Production* memo). presented information to stakeholders regarding the updates under consideration. In December 2024, EPA released a draft memorandum that discussed changes under consideration and requested stakeholder feedback on those changes. EPA then released a final memorandum documenting the methodology implemented in the current *Inventory*.[73] The memorandum cited in the Recalculations Discussion below is: *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2023: Updates to Use New Offshore Data* (*Offshore Production* memo).

EPA evaluated relevant information available and made updates to the *Inventory* for offshore production sources in Gulf of America (GOA) federal and state waters. General information for these source specific recalculations is presented below and details are available in the *Offshore Production* memo.

In addition to the updates to the offshore production sources mentioned above, for certain sources, CH_4 and/or CO_2 emissions changed by greater than 0.05 MMT CO_2 Eq., comparing the previous estimate for 2022 to the current (recalculated) estimate for 2022. The emissions changes were mostly due to GHGRP data submission revisions and updated Enverus data. These sources are discussed below and include pneumatic controllers, chemical injection pumps, produced water, production storage tanks, miscellaneous production flaring, and refinery flaring.

The combined impact of revisions to 2022 petroleum systems CH_4 emission estimates on a CO_2-equivalent basis, compared to the previous *Inventory*, is a decrease from 39.6 to 36.3 MMT CO_2 Eq. (3.4

[71] See https://www.epa.gov/ghgemissions/us-gridded-methane-emissions.

[73] Stakeholder materials including draft and final memoranda for the current (i.e., 1990 to 2023) *Inventory* are available at https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems.

MMT CO_2 Eq., or 8 percent). The recalculations resulted in lower CH_4 emission estimates on average across the 1990 through 2022 time series, compared to the previous *Inventory*, by 0.08 MMT CO_2 Eq., or 0.2 percent.

The combined impact of revisions to 2022 petroleum systems CO_2 emission estimates, compared to the previous *Inventory*, is a slight increase from 21.97 to 22.08 MMT CO_2 (0.12 MMT CO_2, or 0.5 percent). The recalculations resulted in higher emission estimates on average across the 1990 through 2022 time series, compared to the previous *Inventory*, by less than 0.005 MMT CO_2 Eq., or less than 0.1 percent.

The combined impact of revisions to 2022 petroleum systems N_2O emission estimates on a CO_2-equivalent basis, compared to the previous *Inventory*, is an increase of 0.001 MMT CO_2, Eq. or 1 percent. The recalculations resulted in an average increase in emission estimates across the 1990 through 2022 time series, compared to the previous *Inventory*, of 0.001 MMT CO_2 Eq., or 9 percent.

Table 3-52and Table 3-53 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 2022 to the current (recalculated) estimate for 2022. For more information, please see the discussion below.

Table 3-52: Recalculations of CO_2 in Petroleum Systems (MMT CO_2)

Segment/Source	*Previous Estimate Year 2022, 2024 Inventory*	Current Estimate Year 2022, 2025 *Inventory*	Current Estimate Year 2023, 2025 *Inventory*
Exploration	***0.3***	**0.3**	**0.5**
Production	***18.8***	**18.9**	**19.9**
Tanks	*4.5*	4.6	4.6
Miscellaneous Production Flaring	*5.0*	5.1	6.1
Offshore Production - GOA Federal Waters	+	+	+
Offshore Production - GOA State Waters	+	+	+
Transportation	**+**	**+**	**+**
Refining	***2.9***	**2.8**	**2.9**
Flares	*2.8*	2.8	2.8
Petroleum Systems Total	***22.0***	**22.1**	**23.3**

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

Table 3-53: Recalculations of CH_4 in Petroleum Systems (MMT CO_2 Eq.)

Segment/Source	*Previous Estimate Year 2022, 2024 Inventory*	Current Estimate Year 2022, 2025 *Inventory*	Current Estimate Year 2023, 2025 *Inventory*
Exploration	***0.1***	**0.1**	**0.1**
Production	***38.6***	**35.2**	**37.0**
Pneumatic Controllers	*19.4*	18.5	16.3
Chemical Injection Pumps	*2.2*	2.1	1.8
Produced Water	*2.7*	2.4	2.5
Offshore Production - GOA Federal Waters	*4.6*	2.4	2.4
Offshore Production - GOA State Waters	+	+	+
Transportation	***0.2***	**0.2**	**0.3**

Segment/Source	*Previous Estimate Year 2022, 2024 Inventory*	Current Estimate Year 2022, 2025 *Inventory*	Current Estimate Year 2023, 2025 *Inventory*
Refining	***0.7***	**0.7**	**0.7**
Petroleum Systems Total	***39.6***	**36.3**	**38.0**

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

Exploration

There were no methodological updates for exploration and recalculations for the exploration segment have resulted in minor changes in calculated CH_4 and CO_2 emissions over the time series. Methane emissions have decreased by an average of 0.1 percent and CO_2 emissions have increased by an average of 0.1 percent across the time series, compared to the previous *Inventory*.

Production

Offshore Production in Gulf of America (Methodological Update)

EPA updated the calculation methodology for offshore production in the Gulf of America (GOA) to use new emission factors calculated from year 2021 data from the Bureau of Ocean Energy Management (BOEM). Offshore production in the GOA occurs in two areas, federal waters and state waters. BOEM provides periodic emission inventories which account for emissions specific to GOA federal waters production. Previously, year 2017 BOEM data were the most recent that were incorporated into the Inventory's calculation methodology. EPA previously applied emission source-specific emission factors calculated from BOEM's 2017 dataset to calculate emissions for all years from 2016 – 2022 for GOA federal waters. EPA then calculated GOA state waters emissions using the federal waters emissions, assuming the emissions were equivalent on a production basis. With the release of the BOEM 2021 dataset, EPA calculated new emission source-specific emission factors. EPA applied the same approach to calculate emission factors from the 2021 BOEM dataset as it did for the prior BOEM datasets. EPA applied the emission factors calculated from the BOEM 2021 dataset for years 2020 – 2023, maintained the emission factors from the BOEM 2017 dataset for 2016 – 2018, and calculated emission factors that average both BOEM datasets together for year 2019. This update impacts sources of vent and leak emissions only, flaring emissions are not affected. Details and additional considerations for this update are available in the Offshore Production memo.

As a result of this methodological update, CH_4 emissions estimates for offshore production in the GOA are on average 40 percent lower for 2019 to 2022 compared to the previous *Inventory*. The 2022 CH_4 emissions estimate is 48 percent lower than in the previous *Inventory*. The update resulted in CO_2 emissions estimates for offshore production in the GOA that are on average 30 percent lower for 2019 to 2022 compared to the previous *Inventory*. The 2022 CO_2 emissions estimate is 36 percent lower than in the previous *Inventory*. This methodological update impacted CH_4 and CO_2 estimates for 2019 to 2022, compared to the previous *Inventory*. The methodological update did not impact emissions for years prior to 2019; differences in emissions compared to the previous *Inventory* for years prior to 2019 are due to changes in underlying activity data (e.g., number of offshore complexes, oil and gas production).

Table 3-54: GOA Offshore Production Vent and Leak National CH_4 Emissions (Metric Tons CH_4)

Source	1990	2005	2019	2020	2021	2022	2023
GOA Federal Waters - Major Complexes	271,602	187,140	119,930	76,088	73,303	71,609	72,838
GOA Federal Waters - Minor Complexes	31,672	32,356	19,204	15,572	14,580	14,210	14,533
GOA State Waters	26,198	2,861	842	484	385	454	424
Total Emissions	**329,472**	**222,357**	**139,976**	**92,144**	**88,267**	**86,272**	**87,795**
Previous Estimate	*308,543*	*219,893*	*178,558*	*167,001*	*165,720*	*164,395*	*NA*

NA (Not Applicable)
Note: Totals may not sum due to independent rounding.

Table 3-55: GOA Offshore Production Vent and Leak National CO_2 Emissions (Metric Tons CO_2)

Source	1990	2005	2019	2020	2021	2022	2023
GOA Federal Waters - Major Complexes	3,010	2,299	1,624	902	869	848	863
GOA Federal Waters - Minor Complexes	402	411	489	682	639	622	637
GOA State Waters	295	35	13	8	7	8	7
Total Emissions	**3,707**	**2,745**	**2,125**	**1,592**	**1,514**	**1,479**	**1,507**
Previous Estimate	*3,702*	*2,741*	*2,525*	*2,359*	*2,341*	*2,324*	*NA*

NA (Not Applicable)
Note: Totals may not sum due to independent rounding.

Pneumatic Controllers (Recalculation with Updated Data)

Methane emissions from onshore production pneumatic controllers are on average 0.1 percent lower across the time series and 5 percent lower in 2022, compared to the previous *Inventory*. The emission changes were due to GHGRP data submission revisions and updated oil well counts.

Table 3-56: Pneumatic Controllers National CH_4 Emissions (Metric Tons CH_4)

Source	1990	2005	2019	2020	2021	2022	2023
High Bleed Controllers	709,646	483,896	73,071	87,173	45,577	24,282	14,184
Low Bleed Controllers	51,050	62,291	49,997	36,751	45,991	35,659	31,292
Intermittent Bleed Controllers	NO	267,908	744,789	975,122	875,857	602,017	535,139
Total Emissions	**760,696**	**814,095**	**867,857**	**1,099,046**	**967,425**	**661,958**	**580,615**
Previous Estimate	*760,925*	*811,142*	*881,203*	*1,119,352*	*1,003,063*	*693,551*	*NA*

NA (Not Applicable)
Note: Totals may not sum due to independent rounding.

Chemical Injection Pumps (Recalculation with Updated Data)

Methane emissions from chemical injection pumps are on average 0.2 percent lower across the time series and 5 percent lower in 2022, compared to the previous *Inventory*. The emission changes were due to GHGRP data submission revisions and updated oil well counts.

Table 3-57: Chemical Injection Pump National CH_4 Emissions (Metric Tons CH_4)

Source	1990	2005	2019	2020	2021	2022	2023
Chemical Injection Pumps	47,480	80,259	117,570	93,396	82,592	75,695	64,163
Previous Estimate	*47,425*	*79,968*	*122,967*	*96,186*	*85,494*	*79,712*	*NA*

NA (Not Applicable)

Produced Water (Recalculation with Updated Data)

Methane emissions from produced water are on average 0.6 percent lower across the time series and 10 percent lower in 2022, compared to the previous *Inventory*. The emission changes were due to updated produced water volumes.

Table 3-58: Produced Water National CH_4 Emissions (Metric Tons CH_4)

Source	1990	2005	2019	2020	2021	2022	2023
Produced Water - Regular Pressure Wells	71,923	49,898	77,459	70,460	62,718	66,488	70,204
Produced Water - Low Pressure Wells	20,502	14,224	22,080	20,085	17,878	18,953	20,012
Total Emissions	**92,425**	**64,122**	**99,539**	**90,545**	**80,596**	**85,440**	**90,216**
Previous Estimate	*92,336*	*64,047*	*99,425*	*90,435*	*92,201*	*94,663*	*NA*

NA (Not Applicable)
Note: Totals may not sum due to independent rounding.

Storage Tanks (Recalculation with Updated Data)

Carbon dioxide emissions from production storage tanks are on average 1 percent higher across the time series, compared to the previous *Inventory*. Carbon dioxide emission estimates for 2022 are 1 percent higher than in the previous *Inventory*, which is primarily due to large tanks with flares. The emission changes were due to updated oil production volumes.

Table 3-59: Storage Tanks National CO_2 Emissions (kt CO_2)

Source	1990	2005	2019	2020	2021	2022	2023
Large Tanks w/Flares	0	718	6,213	5,805	5,581	4,567	4,594
Large Tanks w/VRU	0	3	9	2	1	1	0
Large Tanks w/o Control	24	8	9	5	4	2	3
Small Tanks w/Flares	0	3	9	10	10	11	10
Small Tanks w/o Flares	12	5	4	4	5	5	4
Malfunctioning Separator Dump Valves	12	13	26	21	34	8	11
Total Emissions	**48**	**750**	**6,270**	**5,848**	**5,636**	**4,593**	**4,622**
Previous Estimate	*47*	*748*	*6,024*	*5,255*	*5,439*	*4,539*	*NA*

NA (Not Applicable)
Note: Totals may not sum due to independent rounding.

Miscellaneous Production Flaring (Recalculation with Updated Data)

Carbon dioxide emissions from miscellaneous production flaring are on average 0.1 percent higher across the time series and 1 percent higher in 2022, compared to the previous *Inventory*. The emission changes were due to updated oil production volumes.

Table 3-60: Miscellaneous Production Flaring National CO_2 Emissions (kt CO_2)

Source	1990	2005	2019	2020	2021	2022	2023
220 – Gulf Coast Basin (LA, TX)	0	103	608	652	802	656	1,069
395 – Williston Basin	0	71	3,049	1,307	1,313	1,241	1,232
430 – Permian Basin	0	215	4,315	2,728	2,159	2,767	3,391
"Other" Basins	0	398	704	424	370	428	407
Total Emissions	**0**	**787**	**8,677**	**5,112**	**4,644**	**5,092**	**6,100**
Previous Estimate	*0*	*786*	*8,678*	*5,110*	*4,638*	*5,028*	*NA*

NA (Not Applicable)
Note: Totals may not sum due to independent rounding.

Transportation

Recalculations for the transportation segment have resulted in calculated CH_4 and CO_2 emissions over the time series from this segment that are lower (by less than 0.1percent) than in the previous *Inventory*.

Refining

Recalculations due to resubmitted GHGRP data in the refining segment have resulted in an increase in calculated CH_4 emissions by an average of 3.7 percent across the time series and a decrease of 0.6 percent in 2022, compared to the previous *Inventory*.

Refining CO_2 emission estimates decreased by an average of 0.1 percent across the time series and decreased by 1.8 percent in 2022, compared to the previous *Inventory*. This change in emissions is due to GHGRP resubmissions and was largely due to a change in reported flaring CO_2 emissions.

Table 3-61: Refining National CH_4 Emissions (Metric Tons CH_4)

Source	1990	2005	2019	2020	2021	2022	2023
Refining	26,774	30,389	30,779	25,794	25,299	24,529	23,579
Previous Estimate	*25,742*	*29,218*	*30,814*	*25,861*	*25,366*	*24,685*	*NA*

NA (Not Applicable)

Table 3-62: Refining National CO_2 Emissions (kt CO_2)

Source	1990	2005	2019	2020	2021	2022	2023
Flares	3,023	3,431	3,512	2,840	2,969	2,784	2,829
Total Refining	**3,174**	**3,602**	**3,560**	**2,874**	**3,001**	**2,820**	**2,862**
Previous Estimate	*3,174*	*3,602*	*3,571*	*2,893*	*3,021*	*2,872*	*NA*

NA (Not Applicable)

Planned Improvements

Planned Improvements for 2025 Inventory

EPA updated oil and gas well counts and oil and gas production for this 2025 Inventory using Enverus data. However, EPA did not update the number of completion events, due to significant changes in the data across the time series. EPA will assess the underlying Enverus data to develop an appropriate methodology to determine the number of completions for each year of the time series.

Upcoming Data, and Additional Data that Could Inform the Inventory

EPA will assess new data received by the Greenhouse Gas Reporting Program and other relevant programs on an ongoing basis, which may be used to confirm or improve existing estimates and assumptions. In December 2024, EPA released a memorandum discussing updates under consideration for a future *Inventory* to incorporate revised GHGRP subpart W emission factors and requested stakeholder feedback (*Inventory of U.S. Greenhouse Gas Emissions and Sinks: Updates Under Consideration to Use Revised Subpart W Emission Factors*).[74] One commenter provided feedback on the potential subpart W-based revisions. The commenter had concerns with using the revised subpart W equipment leak emission factors though the commenter supported incorporating leaker survey data into the *Inventory's* equipment leaks methodology.

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 previous stakeholder comments.

3.7 Natural Gas Systems (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 category (1B2b) as defined in the IPCC methodological guidance is for fugitive emissions from natural gas systems, which per IPCC guidelines include emissions from leaks, venting, and flaring. Total greenhouse gas emissions (CH_4, CO_2, and N_2O) from natural gas systems in 2023 were 200.1 MMT CO_2 Eq., a decrease of 21 percent from 1990 and a decrease of 4 percent from 2022, both primarily due to decreases in CH_4 emissions. From 2011, emissions decreased by 9 percent, primarily due to decreases in CH_4 emissions. National total dry gas production in the United States increased by 113 percent from 1990 to 2023, increased by 4 percent from 2022 to 2023, and increased by 65 percent from 2011 to 2023. Of the overall greenhouse gas emissions (200.1 MMT CO_2 Eq.), 81 percent are CH_4 emissions (162.4 MMT CO_2 Eq.), 19 percent are CO_2 emissions (37.7 MMT), and less than 0.1 percent are N_2O emissions (0.01 MMT CO_2 Eq.).

Overall, natural gas systems emitted 162.4 MMT CO_2 Eq. (5,802 kt CH_4) of CH_4 in 2023, a 26 percent decrease compared to 1990 emissions, and 6 percent decrease compared to 2022 emissions (see Table 3-64 and Table 3-65). For non-combustion CO_2, a total of 37.7 MMT CO_2 Eq. (37,682 kt) was emitted in 2023, a 16 percent increase compared to 1990 emissions, and a 3 percent increase compared to 2022 levels. The 2023 N_2O emissions were estimated to be 0.01 MMT CO_2 Eq. (0.03 kt N_2O), a 73 percent increase compared to 1990 emissions, and a 55 percent decrease compared to 2022 levels.

[74] The memo is available online: https://www.epa.gov/ghgemissions/stakeholder-process-natural-gas-and-petroleum-systems-1990-2023-inventory

The 1990 to 2023 emissions trend is not consistent across segments or gases. Overall, the 1990 to 2023 decrease in CH_4 emissions is due primarily to the decrease in emissions from the following segments: distribution (70 percent decrease), transmission and storage (42 percent decrease), processing (36 percent decrease), and exploration (98 percent decrease). Over the same time period, the production segment saw increased CH_4 emissions of 23 percent (with onshore production emissions increasing 1 percent, offshore production emissions decreasing 98 percent, and gathering and boosting [G&B] emissions increasing 90 percent), and post-meter emissions increasing by 70 percent. The 1990 to 2023 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.

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 2023) to ensure that the trend is representative of changes in emissions. Recalculations in natural gas systems in this year's *Inventory* include:

- Updates to oil and gas well counts, oil and gas production volumes, and produced water production volumes using the most recent data from Enverus.
- Methodological updates for offshore production in the Gulf of America.
- Recalculations due to Greenhouse Gas Reporting Program (GHGRP) submission revisions.

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

Below is a characterization of the six emission subcategories of natural gas systems: exploration, production (including gathering and boosting), processing, transmission and storage, distribution, and post-meter. 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 completion. Emissions from exploration accounted for 0.1 percent of CH_4 emissions and 0.1 percent of CO_2 emissions from natural gas systems in 2023. Well completions accounted for approximately 87 percent of CH_4 emissions from the exploration segment in 2023, with the rest resulting from well testing and drilling. Well completion flaring emissions account for most of the CO_2 emissions. Methane emissions from exploration decreased by 98 percent from 1990 to 2023, with the largest decreases coming from hydraulically fractured gas well completions without reduced emissions completions (RECs). Methane emissions from exploration decreased 25 percent from 2022 to 2023 due to decreases in emissions from hydraulically fractured well completions (both non-REC with flaring and REC with venting). Methane emissions from exploration were highest from 2006 to 2008. Carbon dioxide emissions from exploration decreased by 94 percent from 1990 to 2023 primarily due to decreases in hydraulically fractured gas well completions. Carbon dioxide emissions from exploration decreased by 2 percent from 2022 to 2023 due to decreases in emissions from hydraulically fractured gas well completions (REC with flaring) and non-hydraulically fractured gas well completions (vented). Carbon dioxide emissions from exploration were highest from 2006 to 2008. Nitrous oxide emissions from exploration decreased 96 percent from 1990 to 2023 and decreased 28 percent from 2022 to 2023.

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 50 percent of CH_4 emissions and 26 percent of CO_2 emissions from natural gas systems in 2023. Emissions from gathering and boosting and pneumatic controllers in onshore production accounted for most of the production segment CH_4 emissions in 2023. 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 23 percent from 1990 to 2023, 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 from production decreased 10 percent from 2022 to 2023 due to decreases in emissions from well pad equipment leaks (compressors) and pneumatic controllers. Carbon dioxide emissions from production increased by approximately a factor of 2.9 from 1990 to 2023 due to increases in emissions at flare stacks in gathering and boosting and miscellaneous onshore production flaring and increased 12 percent from 2022 to 2023 due primarily to increases in emissions at flare stacks at gathering and boosting stations and in miscellaneous onshore production flaring and tank venting. Nitrous oxide emissions from production decreased by 6 percent from 1990 to 2023 due to decreases in emissions from dehydrator units at gathering and boosting stations and decreased 56 percent from 2022 to 2023 due to decreases 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 9 percent of CH_4 emissions and 71 percent of CO_2 emissions from natural gas systems. Methane emissions from processing decreased by 36 percent from 1990 to 2023 as emissions from compressors (leaks and venting) and equipment leaks decreased; and increased 3 percent from 2022 to 2023 due to increased emissions from gas engines. Carbon dioxide emissions from processing decreased by 5 percent from 1990 to 2023, due to a decrease in AGR emissions, and increased 1 percent from 2022 to 2023 due to increased AGR emissions. Nitrous oxide emissions decreased 53 percent from 2022 to 2023 due to decreased emissions from flares at gas processing plants.

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 methane 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 42 percent from 1990 to 2023 due to reduced pneumatic device and compressor station emissions (including emissions from compressors and leaks) and decreased 6 percent from 2022 to 2023 due to decreased emissions from pipeline venting and transmission compressors. CO_2 emissions from transmission and storage were 6.4 times higher in 2023 than in 1990, due to increased emissions from LNG export terminals, and increased by 4 percent from 2022 to 2023, due to increased emissions from LNG stations. The quantity of LNG exported from the United States increased by a factor of 83 from 1990 to 2023, and by 12 percent from 2022 to 2023. LNG emissions are about 2 percent of CH_4 and 86 percent of CO_2 emissions from transmission and storage in year 2023. Nitrous oxide emissions from transmission and storage increased by 68 percent from 1990 to 2023 and decreased by 66 percent from 2022 to 2023.

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 1,364,070 miles of distribution mains in 2023, an increase of 419,913 miles since 1990 (PHMSA 2024). Distribution system emissions, which accounted for 9 percent of CH_4 emissions from natural gas systems and less than 0.1 percent of CO_2 emissions from natural gas systems, 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 2023 were 70 percent lower than 1990 levels and less than 1 percent lower than 2022 emissions. Distribution system CO_2 emissions in 2023 were 70 percent lower than 1990 levels and less than 1 percent lower than 2022 emissions. Annual CO_2 emissions from this segment are less than 0.1 MMT CO_2 Eq. across the time series.

Post-Meter. Post-meter includes leak emissions from residential and commercial appliances, industrial facilities and power plants, and natural gas fueled vehicles. Leak emissions from residential appliances and industrial facilities and power plants account for the majority of post-meter CH_4 emissions. Methane emissions from the post-meter segment accounted for approximately 8 percent of emissions from natural gas systems in 2023. Post-meter CH_4 emissions increased by 70 percent from 1990 to 2023 and increased by 3 percent from 2022 to 2023, due to increases in the number of residential houses using natural gas and increased natural gas consumption at industrial facilities and power plants. CO_2 emissions from post-meter account for less than 0.01 percent of total CO_2 emissions from natural gas systems.

Total greenhouse gas emissions from the six subcategories within natural gas systems are shown in MMT CO_2 Eq. in Table 3-63. Total CH_4 emissions for these same segments of natural gas systems are shown in MMT CO_2 Eq. (Table 3-64) and kt (Table 3-65). 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. In 2023, 2.6 MMT CO_2 Eq. CH_4 is subtracted from production segment emissions, 4.3 MMT CO_2 Eq. CH_4 is subtracted from the transmission and storage segment, and 0.1 MMT CO_2 Eq. CH_4 is subtracted from the distribution 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 3-63: Total Greenhouse Gas Emissions (CH_4, CO_2, and N_2O) from Natural Gas Systems (MMT CO_2 Eq.)

Segment	1990	2005	2019	2020	2021	2022	2023
Exploration	7.3	22.5	2.3	0.3	0.2	0.2	0.2
Production	69.3	98.3	114.9	105.4	101.4	98.3	90.5
Processing	52.2	31.8	40.4	39.5	39.7	41.4	42.0
Transmission and Storage	64.2	46.3	41.8	43.1	40.6	40.7	38.4
Distribution	51.0	28.5	15.5	15.5	15.3	15.3	15.3
Post-Meter	8.1	9.6	12.8	13.0	13.0	13.4	13.8
Total	**252.1**	**237.0**	**227.7**	**216.9**	**210.4**	**209.3**	**200.1**

Note: Totals may not sum due to independent rounding.

Table 3-64: CH_4 Emissions from Natural Gas Systems (MMT CO_2 Eq.)

Segment	1990	2005	2019	2020	2021	2022	2023
Exploration	6.7	19.7	2.1	0.2	0.1	0.2	0.1
Production	65.9	93.7	103.9	96.3	92.1	89.7	80.8
Onshore Production	40.0	64.8	58.2	53.6	50.0	48.6	40.5
Gathering and Boosting	21.1	26.9	45.3	42.5	42.0	41.0	40.2
Offshore Production	*4.8*	*2.0*	*0.5*	*0.1*	*0.1*	*0.1*	*0.1*
Processing	23.9	13.0	14.2	14.0	14.2	14.8	15.2
Transmission and Storage	64.0	46.1	40.6	41.1	39.8	39.6	37.3
Distribution	50.9	28.5	15.5	15.5	15.3	15.2	15.2
Post-Meter	8.1	9.6	12.8	13.0	13.0	13.4	13.8
Total	**219.6**	**210.7**	**189.0**	**180.1**	**174.6**	**172.8**	**162.4**

Note: Totals may not sum due to independent rounding.

Table 3-65: CH_4 Emissions from Natural Gas Systems (kt)

Segment	1990	2005	2019	2020	2021	2022	2023
Exploration	239	705	75	7	5	6	5
Production	2,354	3,348	3,711	3,438	3,289	3,203	2,886
Onshore Production	1,429	2,314	2,079	1,914	1,785	1,736	1,447
Gathering and Boosting	755	960	1,616	1,519	1,500	1,463	1,436
Offshore Production	*170*	*73*	*16*	*5*	*4*	*3*	*3*
Processing	853	463	506	501	508	529	544
Transmission and Storage	2,286	1,646	1,448	1,468	1,421	1,413	1,330
Distribution	1,819	1,018	554	553	547	544	544
Post-Meter	290	344	457	464	465	478	492

Total	7,842	7,525	6,751	6,431	6,236	6,173	5,802

Note: Totals may not sum due to independent rounding.

Table 3-66: CO_2 Emissions from Natural Gas Systems (MMT)

Segment	1990	2005	2019	2020	2021	2022	2023
Exploration	0.6	2.7	0.2	0.1	0.0	+	+
Production	3.3	4.6	11.0	9.2	9.3	8.6	9.7
Processing	28.3	18.8	26.2	25.5	25.5	26.6	26.8
Transmission and Storage	0.2	0.2	1.2	2.0	0.9	1.1	1.2
Distribution	0.1	+	+	+	+	+	+
Post-Meter	+	+	+	+	+	+	+
Total	**32.5**	**26.3**	**38.7**	**36.8**	**35.7**	**36.4**	**37.7**

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

Table 3-67: CO_2 Emissions from Natural Gas Systems (kt)

Segment	1990	2005	2019	2020	2021	2022	2023
Exploration	619	2,708	249	97	38	37	36
Production	3,332	4,562	11,000	9,173	9,330	8,648	9,686
Processing	28,338	18,836	26,184	25,494	25,502	26,588	26,781
Transmission and Storage	182	189	1,244	2,028	857	1,118	1,160
Distribution	54	30	16	16	16	16	16
Post-Meter	1	1	2	2	2	2	2
Total	**32,525**	**26,325**	**38,696**	**36,810**	**35,745**	**36,410**	**37,682**

Note: Totals may not sum due to independent rounding.

Table 3-68: N_2O Emissions from Natural Gas Systems (Metric Tons CO_2 Eq.)

Segment	1990	2005	2019	2020	2021	2022	2023
Exploration	518	1,707	114	46	19	27	19
Production	3,983	5,204	5,098	3,737	3,955	8,385	3,729
Processing	NO	2,977	5,088	4,367	4,098	8,672	4,033
Transmission and Storage	229	280	563	941	399	1,142	384
Distribution	NO	NO	NO	NO	NO	NO	NO
Post-Meter	NO	NO	NO	NO	NO	NO	NO
Total	**4,730**	**10,169**	**10,863**	**9,091**	**8,471**	**18,227**	**8,165**

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

Table 3-69: N_2O Emissions from Natural Gas Systems (Metric Tons N_2O)

Segment	1990	2005	2019	2020	2021	2022	2023
Exploration	2.0	6.4	0.4	0.2	0.1	0.1	0.1
Production	15.0	19.6	19.2	14.1	14.9	31.6	14.1
Processing	NO	11.2	19.2	16.5	15.5	32.7	15.2
Transmission and Storage	0.9	1.1	2.1	3.6	1.5	4.3	1.4
Distribution	NO	NO	NO	NO	NO	NO	NO
Post-Meter	NO	NO	NO	NO	NO	NO	NO
Total	**17.9**	**38.4**	**41.0**	**34.3**	**32.0**	**68.8**	**30.8**

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

Methodology and Time-Series Consistency

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 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 an IPCC 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), EPA's GHGRP (EPA 2024), 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 time 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 time series.

Other data sources used for CH_4 emission factors include Zimmerle et al. (2015) for transmission and storage station leaks and compressors, 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, Bureau of Ocean Energy Management (BOEM) reports, and Fischer et al. (2018) and IPCC (2019) for post-meter emissions.

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 the 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 GTI publication (1993) were used to adapt the CH_4 emission factors into non-combustion related CO_2 emission factors. CO_2 emissions from post-meter sources (commercial, industrial and vehicles) were estimated using default emission factors from IPCC (2019). Carbon dioxide emissions from post-meter residential sources are included in fossil fuel combustion data.

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 2024); Enverus (Enverus 2025); BOEM; Federal Energy Regulatory Commission (FERC) (FERC 2024); EIA; the Natural Gas STAR and Methane Challenge Programs annual data; Oil and Gas Journal; and PHMSA.

For a few sources, recent direct activity data are not available. For these sources, either 2022 data were used as a proxy for 2023 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, transmission and storage, and distribution, some sources are calculated using potential emission factors, and CH_4 that is not emitted is deducted from the total CH_4 potential estimates. To account for 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 and Methane Challenge for certain sources.

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990 through 2023. Available GHGRP data (beginning 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.

The notation key "IE" is used for CO_2 and CH_4 emissions from venting and flaring in common data tables category 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

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 memoranda *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2016: Natural Gas and Petroleum Systems Uncertainty Estimates* (*2018 Uncertainty memo*) and *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2019: Update for Natural Gas and Petroleum Systems CO_2 Uncertainty Estimates* (*2021 Uncertainty memo*).[75]

EPA used Palisade's @RISK add-in tool for Microsoft Excel to estimate the 95 percent confidence bound around CH_4 and CO_2 emissions from natural gas systems for the current *Inventory*. For the CH_4 uncertainty analysis, EPA focused on the 6 highest-emitting sources for the year 2023, which together emitted 51 percent of methane from natural gas systems in 2023, and extrapolated the estimated uncertainty for the remaining sources. For the CO_2 uncertainty analysis, EPA focused on the highest-emitting source for the year 2023, which emitted 50 percent of CO_2 from natural gas systems in 2023, and extrapolated the estimated uncertainty for the remaining sources. To estimate uncertainty for N_2O, EPA applied the uncertainty bounds calculated for CO_2. EPA will seek to refine this estimate in future Inventories. 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. For emission factors that are derived from methane emissions measurement studies, the PDFs are commonly determined to be lognormally distributed (GRI/EPA 1996; GTI 2001; GTI 2009; Lamb et al. 2015; Zimmerle et al. 2015; Fischer et al. 2018; GTI

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

2019). For activity data that are derived from national datasets, the PDFs are set to a uniform distribution (see 2018 and 2021 Uncertainty memos). Many emission factors and activity factors are calculated using Subpart W data, and for these, the @RISK add-in determines the best fitting PDF (e.g., lognormal, gaussian), based on bootstrapping of the underlying data (see 2018 and 2021 Uncertainty memos). The IPCC guidance notes that in using this Approach 2 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 2023, using the IPCC methodology. The results of the Approach 2 uncertainty analysis are summarized in Table 3-70. Natural gas systems CH_4 emissions in 2023 were estimated to be between 146.4 and 179.9 MMT CO_2 Eq. at a 95 percent confidence level. Natural gas systems CO_2 emissions in 2023 were estimated to be between 32.4 and 44.1 MMT CO_2 Eq. at a 95 percent confidence level. Natural gas systems N_2O emissions in 2023 were estimated to be between 0.008 and 0.010 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 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 3-70: 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	2023 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	162.4	146.1	179.9	-10%	+11%
Natural Gas Systems	CO_2	37.7	32.4	44.1	-14%	+17%
Natural Gas Systems	N_2O	0.008	0.007	0.010	-14%	+17%

[a] Range of emission estimates estimated by applying the 95 percent confidence intervals obtained from the Monte Carlo simulation analysis conducted for the year 2023 CH_4 and 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 3-61 and Table 3-62.

QA/QC and Verification Discussion

In order to ensure the quality of the emission estimates for natural gas systems, general (IPCC Tier 1) Quality Assurance/Quality Control (QA/QC) procedures were implemented consistent with the U.S. Inventory QA/QC plan outlined in Annex 8.

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.[76]

As in previous years, EPA conducted early engagement and communication with stakeholders on updates prior to public review of the current *Inventory*. EPA held a stakeholder webinar in November 2024. EPA released a memo detailing updates under consideration and requesting stakeholder feedback.

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

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 spatial and

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

temporal scales, EPA has 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.[77] The most recent version of the gridded methane inventory is designed to be consistent with the U.S. EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2018* estimates for the years 2012 to 2018. The gridded inventory improves efforts to compare results of this *Inventory* with atmospheric studies.

Recalculations Discussion

EPA received information and data related to the emission estimates through GHGRP reporting and presented information to stakeholders regarding the updates under consideration. In December 2024, EPA released a draft memorandum that discussed changes under consideration and requested stakeholder feedback on those changes. EPA then released a final memorandum documenting the methodology implemented in the current *Inventory*.[78] The memorandum cited in the Recalculations Discussion below is: Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2023: Updates to Use New Offshore Data (*Offshore Production* memo).

EPA evaluated relevant information available and made updates to the *Inventory*, including for offshore production in the Gulf of America (GOA). General information for the source specific recalculations is presented below and details are available in the *Offshore Production* memo.

In addition to the updates to the source mentioned above, for certain sources, CH_4 and/or CO_2 emissions changed by greater than 0.05 MMT CO_2 Eq., comparing the previous estimate for 2022 to the current (recalculated) estimate for 2022. The emissions changes were mostly due to GHGRP data submission revisions and updated Enverus data. These sources are discussed below and include pneumatic controllers, chemical injection pumps, liquids unloading, wellpad equipment leaks, kimray pumps, produced water, and offshore production (in the production segment); gathering and boosting (G&B) dehydrators, pneumatic controllers, blowdowns, and storage tanks; natural gas processing blowdowns and acid gas removal (AGR); and LNG export sources.

The combined impact of revisions to 2022 natural gas systems CH_4 emissions, compared to the previous *Inventory*, is a decrease from 173.1 to 172.8 MMT CO_2 Eq. (0.3 MMT CO_2 Eq., or 0.2 percent). The recalculations resulted in an average increase in the annual CH_4 emission estimates across the 1990 through 2022 time series, compared to the previous *Inventory*, of 0.25 MMT CO_2 Eq., or about 0.1 percent.

The combined impact of revisions to 2022 natural gas systems CO_2 emissions, compared to the previous *Inventory*, is a decrease from 36.5 MMT to 36.4 MMT (0.1 MMT or 0.2 percent). The recalculations resulted in an average increase in emission estimates across the 1990 through 2022 time series, compared to the previous *Inventory*, of less than 0.1 MMT CO_2 Eq., or less than 0.1 percent.

The combined impact of revisions to 2022 natural gas systems N_2O emissions, compared to the previous *Inventory*, is a decrease from 152.0 kt CO_2 Eq. to 18.2 kt CO_2 Eq., or 88 percent. This change for 2022 was due to a correction in the emission factor calculation for production storage tank flaring. The

[77] See https://www.epa.gov/ghgemissions/us-gridded-methane-emissions.

[78] Stakeholder materials including draft and final memoranda for the current (i.e., 1990 to 2023) *Inventory* are available at https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems.

recalculations resulted in an average decrease in emission estimates across the 1990 through 2022 time series, compared to the previous *Inventory*, of 4.5 kt CO_2 Eq., or 7 percent.

In Table 3-71 and Table 3-72 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 2022 to the current (recalculated) estimate for 2022. 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 3-71: Recalculations of CO_2 in Natural Gas Systems (MMT CO_2)

Segment and Emission Sources with Changes of Greater than 0.05 MMT CO_2 due to Recalculations	*Previous Estimate Year 2022, 2024 Inventory*	Current Estimate Year 2022, 2025 *Inventory*	Current Estimate Year 2023, 2025 *Inventory*
Exploration	**+**	**+**	**+**
Production	***8.6***	**8.6**	**9.7**
Offshore Production - GOA Federal Waters	+	+	+
Offshore Production - GOA State Waters	+	+	+
Processing	***26.7***	**26.6**	**26.8**
AGR Vents	*18.1*	18.0	18.7
Transmission and Storage	***1.2***	**1.1**	**1.2**
LNG Export Terminals (equipment leaks, compressors, flares)	*1.0*	0.9	0.9
Distribution	**+**	**+**	**+**
Post-Meter	**+**	**+**	**+**
Total	***36.5***	**36.4**	**37.7**

+ Does not exceed 0.05 MMT CO_2 Eq.

Note: Totals may not sum due to independent rounding.

Table 3-72: Recalculations of CH_4 in Natural Gas Systems (MMT CO_2 Eq.)

Segment and Emission Sources with Changes of Greater than 0.05 MMT CO_2 Eq. due to Recalculations	*Previous Estimate Year 2022,* 2024 Inventory	Current Estimate Year 2022, 2025 *Inventory*	Current Estimate Year 2023, 2025 *Inventory*
Exploration	**+**	**+**	**+**
Production	***89.7***	**89.7**	**80.8**
Pneumatic Controllers	*18.0*	19.9	16.4
Chemical Injection Pumps	*2.1*	2.0	1.7
Liquids Unloading	*2.4*	2.3	1.4
Wellpad Equipment Leaks	*10.8*	11.5	8.0
Produced Water	*4.0*	3.9	4.1
Kimray Pumps	*0.8*	0.9	0.9
Offshore Production - GOA Federal Waters	*0.4*	0.05	0.04
Offshore Production - GOA State Waters	*0.3*	0.04	0.04
G&B Stations – Tanks	*8.7*	6.9	5.3
G&B Stations – Station Blowdowns	*0.9*	1.0	0.9
G&B Stations – Dehydrator Vents	*1.1*	1.2	1.1
G&B Stations – Pneumatic Controllers	*4.8*	4.6	3.9
Processing	***15.1***	**14.8**	**15.2**
Blowdowns/Venting	*1.3*	0.9	0.6

Segment and Emission Sources with Changes of Greater than 0.05 MMT CO_2 Eq. due to Recalculations	*Previous Estimate Year 2022,* 2024 Inventory	Current Estimate Year 2022, 2025 *Inventory*	Current Estimate Year 2023, 2025 *Inventory*
Transmission and Storage	*39.6*	39.6	37.3
Distribution	+	+	+
Post-Meter	*13.4*	13.4	13.8
Total	*173.1*	172.8	162.4

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

Exploration

There were no methodological updates for exploration and recalculations resulted in an average increase in CH_4 emissions across the time series of 1 percent and an average increase in calculated CO_2 emissions across the time series of 0.5 percent, compared to the previous *Inventory*.

Production

Offshore Production in Gulf of America (Methodological Update)

EPA updated the calculation methodology for offshore production in the Gulf of America (GOA) to use new emission factors calculated from year 2021 data from the Bureau of Ocean Energy Management (BOEM) (BOEM 2023). Offshore production in the GOA occurs in two areas, federal waters and state waters. State waters are closer to the shoreline and federal waters are beyond this. BOEM provides periodic emission inventories which account for emissions specific to GOA federal waters production. Previously, year 2017 BOEM data were the most recent that was incorporated into the *Inventory's* calculation methodology. EPA previously applied emission source-specific emission factors calculated from BOEM's 2017 dataset to calculate emissions for all years from 2016 – 2022 for GOA federal waters. EPA then calculated GOA state waters emissions using the federal waters emissions, assuming the emissions were equivalent on a production basis. With the release of the BOEM 2021 dataset, EPA calculated new emission source-specific emission factors. EPA applied the same approach to calculate emission factors from the 2021 BOEM dataset as it did for the prior BOEM datasets. EPA applied the emission factors calculated from the BOEM 2021 dataset for years 2020 – 2023, maintained the emission factors from the BOEM 2017 dataset for 2016 – 2018, and calculated emission factors that average both BOEM datasets together for year 2019. This update impacts sources of vent and leak emissions only, flaring emissions are not affected. Details for this update are available in the *Offshore Production* memo.

As a result of this methodological update, CH_4 emissions estimates for offshore production in the GOA are on average 76 percent lower for 2019 - 2022 compared to the previous *Inventory*. The 2022 CH_4 emissions estimate is 87 percent lower than in the previous *Inventory*. The update resulted in CO_2 emissions estimates for offshore production in the GOA that are on average 82 percent lower for 2019 - 2022 compared to the previous *Inventory*. The 2022 CO_2 emissions estimate is 94 percent lower than in the previous *Inventory*. The emission decreases are due to lower emission factors calculated from the BOEM 2021 dataset compared to the BOEM 2017 dataset. The methodological update did not impact emissions for years prior to 2019; differences in emissions compared to the previous *Inventory* for years prior to 2019 are due to changes in underlying activity data (e.g., number of offshore complexes, oil and gas production).

Table 3-73: GOA Offshore Production Vent and Leak National CH_4 Emissions (Metric Tons CH_4)

Source	1990	2005	2019	2020	2021	2022	2023
GOA Federal Waters - Major Complexes	134,807	43,272	8,327	1,946	1,243	1,271	1,042
GOA Federal Waters - Minor Complexes	19,354	17,685	1,142	543	337	344	284
GOA State Waters	14,202	10,675	6,068	1,962	1,365	1,260	1,538
Total Emissions	**168,364**	**71,633**	**15,537**	**4,451**	**2,945**	**2,875**	**2,863**
Previous Estimate	*168,151*	*71,526*	*27,136*	*31,148*	*21,533*	*22,712*	*NA*

NA (Not Applicable)
Note: Totals may not sum due to independent rounding.

Table 3-74: GOA Offshore Production Vent and Leak National CO_2 Emissions (Metric Tons CO_2)

Source	1990	2005	2019	2020	2021	2022	2023
GOA Federal Waters - Major Complexes	1,514	342	248	19	12	12	10
GOA Federal Waters - Minor Complexes	410	374	14	18	11	11	9
GOA State Waters	177	125	168	29	20	18	22
Total Emissions	**2,100**	**842**	**431**	**65**	**43**	**42**	**42**
Previous Estimate	*2,098*	*840*	*802*	*920*	*638*	*673*	*NA*

NA (Not Applicable)
Note: Totals may not sum due to independent rounding.

Chemical Injection Pumps (Recalculation with Updated Data)

Chemical injection pump CH_4 emission estimates resulted in an average decrease of 0.1 percent across the time series compared to the previous *Inventory*. The estimate for 2022 is 5 percent lower than the previous *Inventory*. These changes were due to GHGRP submission revisions and updated gas well counts.

Table 3-75: Chemical Injection Pumps National CH_4 Emissions (Metric Tons CH_4)

Source	1990	2005	2019	2020	2021	2022	2023
Chemical Injection Pumps	25,563	80,288	111,734	87,266	76,698	72,604	62,414
Previous Estimate	*25,587*	*80,213*	*111,631*	*87,227*	*76,893*	*76,407*	*NA*

NA (Not Applicable)

Pneumatic Controllers (Recalculation with Updated Data)

Pneumatic controller CH_4 emissions estimates are on average 1.4 percent higher across the time-series than in the previous *Inventory*. The estimate for 2022 is 11 percent higher than in the previous *Inventory*. These changes were due to GHGRP submission revisions and updated gas well counts.

Table 3-76: Pneumatic Controllers National CH_4 Emissions (Metric Tons CH_4)

Source	1990	2005	2019	2020	2021	2022	2023
Low Bleed Controllers	0	22,669	23,405	20,551	21,147	27,421	22,842
High Bleed Controllers	358,506	484,469	52,765	42,394	41,566	30,839	11,819
Intermittent Bleed Controllers	235,111	575,207	887,978	772,701	752,638	654,157	549,430

Total Emissions	**593,617**	**1,082,345**	**964,148**	**835,646**	**815,351**	**712,417**	**584,091**
Previous Estimate	*589,332*	*1,067,997*	*958,943*	*817,727*	*747,391*	*643,721*	*NA*

NO (Not Occurring)
NA (Not Applicable)

Liquids Unloading (Recalculation with Updated Data)

Liquids unloading CH_4 emissions estimates decreased by an average of less than 0.1 percent across the 1990 to 2022 time series compared with the previous *Inventory*. The 2022 estimate decreased by 5 percent compared with the previous *Inventory*. These changes were due to GHGRP submission revisions and updated gas well counts.

Table 3-77: Liquids Unloading National CH_4 Emissions (Metric Tons CH_4)

Source	1990	2005	2019	2020	2021	2022	2023
Liquids Unloading With Plunger Lifts	0	128,572	75,230	51,485	33,918	23,869	16,386
Liquids Unloading Without Plunger Lifts	77,822	199,026	104,630	84,551	65,760	56,600	33,989
Total Emissions	**77,822**	**327,598**	**179,860**	**136,037**	**99,678**	**80,470**	**50,376**
Previous Estimate	*77,767*	*327,023*	*179,565*	*135,707*	*99,572*	*84,611*	*NA*

NA (Not Applicable)
Note: Totals may not sum due to independent rounding.

Wellpad Equipment Leaks (Recalculation with Updated Data)

Wellpad equipment leak CH_4 emissions estimates increased by an average of 0.2 percent across the 1990 to 2022 time series compared with the previous *Inventory*. The 2022 estimate increased by 6 percent compared with the previous *Inventory*. These changes were due to GHGRP submission revisions and updated gas well counts.

Table 3-78: Wellpad Equipment Leaks National CH_4 Emissions (Metric Tons CH_4)

Source	1990	2005	2019	2020	2021	2022	2023
Heaters	12,282	18,437	16,205	18,610	17,635	18,595	27,160
Separators	41,496	80,827	126,143	129,208	109,697	94,096	105,200
Dehydrators	12,898	11,394	3,656	3,070	4,081	3,111	3,361
Meters/Piping	42,964	63,842	84,850	154,043	130,602	76,543	75,192
Compressors	30,240	61,781	65,518	61,041	74,234	217,523	75,396
Total Emissions	**139,880**	**236,282**	**296,371**	**365,971**	**336,248**	**409,867**	**286,308**
Previous Estimate	*140,150*	*236,079*	*295,352*	*365,325*	*335,295*	*385,280*	*NA*

NA (Not Applicable)
Note: Totals may not sum due to independent rounding.

Produced Water (Recalculation with Updated Data)

Produced water CH_4 emissions estimates decreased by an average of 0.5 percent across the 1990 to 2022 time series compared with the previous *Inventory*. The 2022 estimate decreased by 3 percent compared with the previous *Inventory*. These changes were due to updated produced water volumes.

Table 3-79: Produced Water National CH_4 Emissions (Metric Tons CH_4)

Source	1990	2005	2019	2020	2021	2022	2023
Produced Water	121,669	152,809	158,918	140,054	130,117	138,837	147,634
Previous Estimate	*121,867*	*153,081*	*159,525*	*140,299*	*140,299*	*143,132*	*NA*

NA (Not Applicable)
Note: Totals may not sum due to independent rounding.

Kimray Pumps (Recalculation with Updated Data)

Kimray pump CH_4 emissions estimates increased by an average of 0.6 percent across the 1990 to 2022 time series compared with the previous *Inventory*. The 2022 estimate increased by 10 percent compared with the previous *Inventory*. These changes were due to updated gas well counts.

Table 3-80: Kimray Pumps National CH_4 Emissions (Metric Tons CH_4)

Source	1990	2005	2019	2020	2021	2022	2023
Kimray Pumps	149,359	92,719	34,876	33,634	31,690	31,479	30,594
Previous Estimate	*149,192*	*92,669*	*34,630*	*33,353*	*31,100*	*28,709*	*NA*

NA (Not Applicable)
Note: Totals may not sum due to independent rounding.

Gathering and Boosting – Storage Tanks (Recalculation with Updated Data)

Gathering and boosting (G&B) station storage tank CH_4 emissions estimates are on average 9 percent lower across the 1990 to 2022 time series than in the previous *Inventory*. The 2022 estimate is 21 percent lower than in the previous *Inventory*. These changes were due to GHGRP submission revisions and a revised approach to determine the number of tanks reported under GHGRP.

Table 3-81: G&B Storage Tanks National Emissions (Metric Tons CH_4)

Source	1990	2005	2019	2020	2021	2022	2023
G&B Storage Tanks	120,816	150,611	293,786	223,609	238,478	244,981	189,262
Previous Estimate	*128,572*	*166,324*	*297,668*	*239,291*	*276,586*	*310,216*	*NA*

NA (Not Applicable)
Note: Totals may not sum due to independent rounding.

Gathering and Boosting – Station Blowdowns (Recalculation with Updated Data)

G&B station blowdown CH_4 emissions estimates are on average 44 percent higher across the 1990 to 2022 time series than in the previous *Inventory*. The 2022 estimate is 13 percent higher than in the previous *Inventory*. These changes were due to GHGRP submission revisions and a revised approach to incorporate blowdown emissions reported under GHGRP when facilities use flow meters to determine emissions.

Table 3-82: G&B Station Blowdowns National Emissions (Metric Tons CH_4)

Source	1990	2005	2019	2020	2021	2022	2023
G&B Station Blowdowns	30,979	38,619	59,948	51,211	40,462	36,269	32,672
Previous Estimate	*20,218*	*26,155*	*39,059*	*40,519*	*35,161*	*32,036*	*NA*

NA (Not Applicable)

Gathering and Boosting – Pneumatic Controllers (Recalculation with Updated Data)

G&B pneumatic controllers CH_4 emissions estimates are on average 0.2 percent higher across the 1990 to 2022 time series compared with the previous *Inventory*. The emissions estimate for 2022 is 4 percent lower than in the previous *Inventory*, largely because of a decrease in emissions from high-bleed pneumatic controllers. These changes were due to GHGRP submission revisions.

Table 3-83: G&B Pneumatic Controllers National Emissions (Metric Tons CH_4)

Source	1990	2005	2019	2020	2021	2022	2023
High-Bleed Pneumatic Controllers	17,751	22,128	22,644	21,608	19,296	17,342	15,259
Intermittent Bleed Pneumatic Controllers	81,445	101,530	184,679	171,860	156,290	139,715	118,834
Low-Bleed Pneumatic Controllers	2,817	3,512	6,938	6,915	6,524	6,504	5,576
Total Emissions	**102,013**	**127,170**	**214,261**	**200,383**	**182,110**	**163,562**	**139,670**
Previous Estimate	*98,229*	*127,072*	*215,725*	*201,625*	*184,116*	*171,000*	*NA*

NA (Not Applicable)
Note: Totals may not sum due to independent rounding.

Gathering and Boosting – Dehydrator Vents (Recalculation with Updated Data)

G&B dehydrator vent CH_4 emissions estimates are on average 0.6 percent higher across the 1990 to 2022 time series compared with the previous *Inventory*. The emissions estimate for 2022 is 7 percent higher than in the previous *Inventory*. These changes were due to GHGRP submission revisions.

Table 3-84: G&B Dehydrator Vent National Emissions (Metric Tons CH_4)

Source	1990	2005	2019	2020	2021	2022	2023
G&B Dehydrator Vents	36,945	46,056	57,148	52,958	59,738	43,491	37,917
Previous Estimate	*35,579*	*46,026*	*57,084*	*52,912*	*59,836*	*40,517*	*NA*

NA (Not Applicable)

Processing

AGR (Recalculation with Updated Data)

Acid gas removal (AGR) CO_2 emission estimates are on average 0.02 percent lower across the time series than in the previous *Inventory*. The CO_2 estimate for 2022 is 0.4 percent lower than in the previous *Inventory*. These changes were due to GHGRP submission revisions.

Table 3-85: Processing Segment AGR National CO_2 Emissions (kt CO_2)

Source	1990	2005	2019	2020	2021	2022	2023
Flares	28,282	15,281	16,371	17,305	18,482	18,003	18,661
Previous Estimate	*28,282*	*15,281*	*16,371*	*17,305*	*18,526*	*18,069*	*NA*

NA (Not Applicable)

Blowdowns (Recalculation with Updated Data)

Processing blowdown CH_4 emissions estimates are on average 0.4 percent lower across the time series than in the previous *Inventory*. The emissions estimate for 2022 is 31 percent lower than in the previous

Inventory. These changes were due to GHGRP submission revisions and a correction in the emission factor calculation.

Table 3-86: Processing Blowdowns National CH_4 Emissions (Metric Tons CH_4)

Source	1990	2005	2019	2020	2021	2022	2023
Blowdowns	59,507	34,244	44,076	50,286	47,458	32,013	20,638
Previous Estimate	*59,507*	*34,244*	*44,581*	*44,197*	*45,370*	*46,188*	*NA*

NA (Not Applicable)

Transmission and Storage

LNG Export Terminals (Recalculation with Updated Data)

LNG export terminal CO_2 emissions estimates are on average 0.3 percent lower across the time series than in the previous *Inventory*. The 2022 estimate is 6 percent lower than in the previous *Inventory*. These changes were due to updated data and GHGRP submission revisions.

Table 3-87: LNG Export Terminals National CO_2 Emissions (kt CO_2)

Source	1990	2005	2019	2020	2021	2022	2023
LNG Export Terminals (eq. leaks, compressors, flares)	0.02	0.02	1,007	1,767	693	940	883
Previous Estimate	*0.02*	*0.02*	*979*	*1,767*	*707*	*1,005*	*NA*

NA (Not Applicable)

Distribution

There were no methodological updates to the distribution segment and recalculations resulted in an average increase in CH_4 emissions across the time series of less than 0.1 percent and an average increase in calculated CO_2 emissions across the time series of less than 0.1 percent, compared to the previous *Inventory*.

Post-Meter

There were no methodological updates to post-meter emissions, and recalculations resulted in an average increase in CH_4 emissions across the time series of less than 0.1 percent and an average increase in calculated CO_2 emissions across the time series of less than 0.1 percent, compared to the previous *Inventory*.

Planned Improvements

Planned Improvements for 2026 Inventory

EPA updated oil and gas well counts and oil and gas production for this 2025 Inventory using Enverus data. However, EPA did not update the number of completion events, due to significant changes in the data across the time series. EPA will assess the underlying Enverus data to develop an appropriate methodology to determine the number of completions for each year of the time series.

Upcoming Data, and Additional Data that Could Inform the Inventory

EPA will assess new data received by EPA's Greenhouse Gas Reporting Program on an ongoing basis, which may be used to validate or improve existing estimates and assumptions. In December 2024, EPA released a memorandum discussing updates under consideration for a future *Inventory* to incorporate revised GHGRP subpart W emission factors and requested stakeholder feedback (Inventory of U.S. Greenhouse Gas Emissions and Sinks: Updates Under Consideration to Use Revised Subpart W Emission Factors).[79] One commenter provided feedback on the potential subpart W-based revisions. The commenter had concerns with using the revised subpart W equipment leak emission factors though the commenter supported incorporating leaker survey data into the *Inventory's* equipment leaks methodology. 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 previous stakeholder comments.

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

The term "abandoned wells", as used in the *Inventory*, encompasses various types of oil and gas 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 oil and gas wells (including orphaned wells and other non-producing wells) is around 3.9 million (with around 3.0 million abandoned oil wells and 0.9 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 United States and the application of emission factors. 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 43 percent of the abandoned well population in the United States is plugged. This fraction has increased over the *Inventory* time series (from around 22 percent in 1990) as more wells fall under regulations and programs requiring or promoting plugging of abandoned wells. Revised abandoned oil and gas well counts from Enverus were not available for this version of the *Inventory*. This version of the *Inventory* used 2022 activity data as proxy for 2023 (Enverus 2023).

[79] The memo is available online: https://www.epa.gov/ghgemissions/stakeholder-process-natural-gas-and-petroleum-systems-1990-2023-inventory

Abandoned oil wells. Abandoned oil wells emitted 235 kt CH_4 and 5 kt CO_2 in 2023. Emissions of both gases increased by 3 percent from 1990, while the total population of abandoned oil wells increased 40 percent.

Abandoned gas wells. Abandoned gas wells emitted 68 kt CH_4 and 3 kt CO_2 in 2023. Emissions of both gases increased by 33 percent from 1990, while the total population of abandoned gas wells increased 83 percent.

Table 3-88: CH_4 Emissions from Abandoned Oil and Gas Wells (MMT CO_2 Eq.)

Activity	1990	2005	2019	2020	2021	2022	2023
Abandoned Oil Wells	6.4	6.6	6.6	6.6	6.6	6.6	6.6
Abandoned Gas Wells	1.4	1.6	1.8	1.9	1.9	1.9	1.9
Total	**7.8**	**8.2**	**8.5**	**8.5**	**8.6**	**8.5**	**8.5**

Note: Totals may not sum due to independent rounding.

Table 3-89: CH_4 Emissions from Abandoned Oil and Gas Wells (kt)

Activity	1990	2005	2019	2020	2021	2022	2023
Abandoned Oil Wells	228	236	237	237	237	235	235
Abandoned Gas Wells	51	58	65	66	69	68	68
Total	**279**	**294**	**302**	**303**	**306**	**303**	**303**

Note: Totals may not sum due to independent rounding.

Table 3-90: CO_2 Emissions from Abandoned Oil and Gas Wells (MMT CO_2)

Activity	1990	2005	2019	2020	2021	2022	2023
Abandoned Oil Wells	+	+	+	+	+	+	+
Abandoned Gas Wells	+	+	+	+	+	+	+
Total	**+**	**+**	**+**	**+**	**+**	**+**	**+**

+ Does not exceed 0.05 MMT CO_2 Eq.

Table 3-91: CO_2 Emissions from Abandoned Oil and Gas Wells (kt)

Activity	1990	2005	2019	2020	2021	2022	2023
Abandoned Oil Wells	5	5	5	5	5	5	5
Abandoned Gas Wells	2	3	3	3	3	3	3
Total	**7**	**7**	**8**	**8**	**8**	**8**	**8**

Note: Totals may not sum due to independent rounding.

Methodology and Time-Series Consistency

EPA uses a Tier 2 method from IPCC (2019) to quantify emissions from abandoned oil and gas wells. EPA's approach is based on the number of plugged and unplugged abandoned wells in the Appalachian region and in the rest of the U.S., and emission factors for plugged and unplugged abandoned wells in Appalachia and the rest of the U.S. Methods for abandoned wells are unavailable in IPCC (2006). The details of this approach and of the data sources used are described in 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).*

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 (using 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 abandoned wells in all other states. 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 same respective emission factors are applied for each year of the time series.

EPA developed state-level annual counts of abandoned wells for 1990 through 2023 by summing together an annual estimate of abandoned wells in the Enverus data set (Enverus 2023), and an estimate of total abandoned wells not included the Enverus dataset (see 2018 Abandoned Wells Memo for additional information on how the value was calculated) for each state. References reviewed to develop the number of abandoned wells not included in the Enverus dataset include historical records collected by state agencies and by USGS.

The state-level abandoned well population was then split into plugged and unplugged wells by applying an assumption that all abandoned wells were unplugged in 1950 and using Enverus data to calculate the fraction of plugged abandoned wells in 2023. Linear interpolation was applied between the 1950 value and 2023 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.[80]

Abandoned Oil Wells

Table 3-92: Abandoned Oil Wells Activity Data, CH_4 and CO_2 Emissions (kt)

Source	1990	2005	2019	2020	2021	2022	2023
Plugged abandoned oil wells	475,939	810,564	1,192,282	1,227,566	1,263,583	1,281,380	1,281,380
Unplugged abandoned oil wells	1,697,730	1,787,095	1,783,807	1,784,834	1,785,340	1,767,543	1,767,543
Total Abandoned Oil Wells	2,173,669	2,597,659	2,976,089	3,012,400	3,048,923	3,048,923	3,048,923
Abandoned oil wells in Appalachia	22%	20%	19%	18%	18%	18%	18%
Abandoned oil wells outside of Appalachia	78%	80%	81%	82%	82%	82%	82%
CH_4 from plugged abandoned oil wells (kt)	0.17	0.25	0.35	0.36	0.36	0.37	0.37
CH_4 from unplugged abandoned oil wells(kt)	227.6	236.1	236.9	237.0	236.8	235.0	235.0
Total CH_4 from abandoned oil wells (kt)	**227.7**	**236.4**	**237.2**	**237.3**	**237.2**	**235.4**	**235.4**
Total CO_2 from abandoned oil wells (kt)	**4.6**	**4.8**	**4.8**	**4.8**	**4.8**	**4.8**	**4.8**

Note: Totals may not sum due to independent rounding.

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

Abandoned Gas Wells

Table 3-93: Abandoned Gas Wells Activity Data, CH_4 and CO_2 Emissions (kt)

Source	1990	2005	2019	2020	2021	2022	2023
Plugged abandoned gas wells	110,089	210,902	359,018	372,605	389,745	395,236	395,236
Unplugged abandoned gas wells	355,620	404,960	448,504	453,988	463,119	457,628	457,628
Total Abandoned Gas Wells	465,709	615,862	807,522	826,593	852,864	852,864	852,864
Abandoned gas wells in Appalachia	28%	25%	24%	24%	26%	26%	26%
Abandoned gas wells outside of Appalachia	72%	75%	76%	76%	74%	74%	74%
CH_4 from plugged abandoned gas wells (kt)	0.06	0.11	0.17	0.19	0.21	0.21	0.21
CH_4 from unplugged abandoned gas wells (kt)	51.1	57.5	64.5	65.9	68.5	67.8	67.8
Total CH_4 from abandoned gas wells (kt)	**51.1**	**57.6**	**64.7**	**66.1**	**68.7**	**68.0**	**68.0**
Total CO_2 from abandoned gas wells (kt)	**2.2**	**2.5**	**2.8**	**2.9**	**3.0**	**3.0**	**3.0**

Note: Totals may not sum due to independent rounding.

Uncertainty

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, 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 3-94 provide the 95 percent confidence bound within which actual emissions from abandoned oil and gas wells are likely to fall for the year 2023, using the recommended IPCC methodology. Abandoned oil well CH_4 emissions in 2023 were estimated to be between 1.1 and 21.3 MMT CO_2 Eq., while abandoned gas well CH_4 emissions were estimated to be between 0.3 and 6.8 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 3-94: 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	2023 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	6.6	1.1	21.3	-83%	+223%
Abandoned Gas Wells	CH_4	1.9	0.3	6.8	-83%	+255%
Abandoned Oil Wells	CO_2	0.005	0.001	0.015	-83%	+223%
Abandoned Gas Wells	CO_2	0.003	0.0005	0.011	-83%	+255%

[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 2023.
[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 the table.

QA/QC and Verification Discussion

The emission estimates in the *Inventory* are continually reviewed and assessed to determine whether emission factors and activity factors accurately reflect current industry practices. In order to ensure the quality of emission estimates for abandoned wells, general (IPCC Tier 1) quality assurance/quality control (QA/QC) procedures were implemented consistent with the U.S. Inventory QA/QC plan outlined in Annex 8. Additionally, EPA reviewed the current Enverus dataset and compared it with results from the previous dataset to identify outliers and instances of significant changes to abandoned oil and gas well counts.

EPA performs a thorough review of information associated with new studies to assess whether the assumptions in the *Inventory* are consistent with industry practices and whether new data is available that could be considered for updates to the estimates. As in previous years, EPA conducted early engagement and communication with stakeholders on updates prior to public review. EPA held a stakeholder webinar on greenhouse gas data for oil and gas in November of 2024.

Recalculations Discussion

Revised abandoned oil and gas well counts from Enverus were not available for this version of the *Inventory*. This version of the *Inventory* used 2022 data as proxy for 2023 (Enverus 2023).

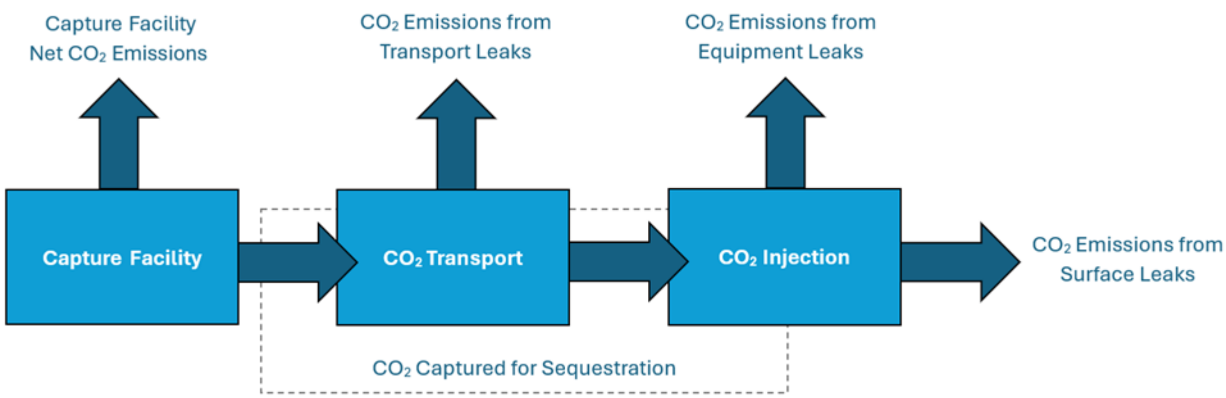
Planned Improvements

EPA will continue to assess new data and stakeholder feedback on considerations (such as potential use of 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. In future Inventories, EPA will assess data that become available from Department of Interior and Department of Energy orphan well plugging programs. EPA will update the 2026 *Inventory* with revised abandoned oil and gas well counts developed from Enverus data.

3.9 CO_2 Transport, Injection, and Geological Storage (Source Category 1C)

Emissions and reductions from CO_2 capture and sequestration are reported under the IPCC sector in which capture takes place, as per the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC 2006). Fugitive emissions from the systems used to transport captured CO_2 from the source to the injection site, fugitive emissions from activities and equipment at the injection site and those from the end containment once the CO_2 is placed in storage are represented as part of CO_2 transport, injection, and geological storage (TIGS) reporting. Figure 3-18 shows the flow and accounting of CO_2 emissions across the CO_2 TIGS chain. Emissions from TIGS are shown in Table 3-95.

Figure 3-18: Flow of CO_2 Capture and Sequestration



Note: The Capture Facility Net CO_2 Emissions are the result of subtracting the amount of CO_2 Captured for Sequestration from the Capture Facility CO_2 Emissions that would have occurred without CO_2 capture.

Table 3-95: Emission from TIGS (kt CO_2)

	1990	2005	2019	2020	2021	2022	2023
Transport	NO	NO	2	2	2	2	2
Injection	NO	NO	16	13	37	28	31
Geological Storage	NO	NO	0	23	26	23	64
Total	**NO**	**NO**	**18**	**39**	**65**	**53**	**98**

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

Sequestered CO_2 is allocated across the different possible source categories as shown in Table 3-96. The source categories are based on information from the Suppliers of CO_2 source category of EPA Greenhouse Gas Reporting Program (GHGRP), 40 CFR Part 98, Subpart PP, also referred to as “Subpart PP” (EPA 2024a). More information is provided in the Methodology section below.

Table 3-96: Allocation of Sequestered CO_2 for *Inventory* Adjustment (kt CO_2)

	1990	2005	2019	2020	2021	2022	2023
Inventory Adjustments Needed							
Power Plants	NO	NO	0	0	0	0	360
Industrial Gas Plants	NO	NO	0	0	0	0	0
Chemical Plants	NO	NO	0	0	0	0	0
Synthetic Gas Production	NO	NO	0	0	0	0	0
Ammonia Plants	NO	NO	0	660	714	652	665
Ethanol Plants	NO	NO	520	522	444	603	903
Breweries	NO	NO	0	0	0	0	0
Distilleries	NO	NO	0	0	0	0	0
Paper Mills	NO	NO	0	0	0	0	0
Total (Inv Adj)	**NO**	**NO**	**520**	**1,182**	**1,158**	**1,255**	**1,928**
Inventory Adjustments Not Needed							
CO_2 Domes	NO	NO	5,716	4,156	3,960	4,624	10,420
Petroleum Refineries	NO	NO	0	0	0	0	0
NG Processing	NO	NO	2,097	1,465	1,835	2,174	3,951
Total (No Adj)	**NO**	**NO**	**7,813**	**5,621**	**5,794**	**6,798**	**14,370**

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

For the CO_2 sequestered sourced from natural domes, there is no adjustment needed to the Inventory since it is considered a transfer from one sink to another. For the CO_2 from Natural gas processing and Petroleum refining there is no need to further adjust the *Inventory* methodology since those emissions are already netted out in the *Inventory*.

For the CO_2 from any other industrial process source the *Inventory* has been adjusted to subtract that CO_2 capture from the source. This includes CO_2 captured from biogenic sources such as ethanol facilities. Since fermentation emissions are biogenic CO_2 emissions, they are not included in the national inventory (these are already included in national totals due to their treatment in the Agricultural, Forestry and Other Land Use [AFOLU] sector). So, the subtraction of the amount of biogenic CO_2 transferred to long-term storage may result in negative emissions. See Section 4.16 for more information on this.

Methodology and Time-Series Consistency

The following section describes the methodology used to estimate CO_2 emissions from transport, injection, and geological storage of CO_2. The allocation approach for determining the source of CO_2 capture for sequestration is also discussed.

Fugitive CO_2 from Transport

To estimate CO_2 emissions from pipeline transport, EPA used the IPCC Tier 1 default factor for pipelines as provided by the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC 2006). In this approach, the leakage emissions estimates from pipeline transport are assumed to be independent of throughput and are based on distance (length) of pipeline. EPA estimated emissions associated with the entire CO_2 pipeline network in the United States. This could potentially overestimate emissions, since the amount of captured CO_2 subtraction at the source for the most part (except for NG Processing and petroleum refining) is based on CO_2 received for sequestration, which would already account for any pipeline losses. However, since that value is uncertain, and other sources of CO_2 (e.g., from natural domes) are not being counted, using total CO_2 pipeline length to estimate transport emissions was deemed appropriate.

The IPCC Tier 1 default fugitive CO_2 emissions rate from pipelines is 0.25-0.28 metric tons CO_2/km pipeline, based on empirical data and analysis. Actual pipeline leakage rates depend on the type and size of equipment installed in the pipeline systems, and are sourced from PHMSA (2024). In 2023, 5,331 miles (8,580 km) of CO_2 pipeline were in operation in the United States. This equates to an estimated average leakage of 2,274 metric tons of CO_2 per year. Annual mileage is shown in Table 3-97.

Table 3-97: Pipeline Mileage (Miles)

	1990	2005	2019	2020	2021	2022	2023
Miles	NO	NO	5,147	5,150	5,339	5,354	5,331

NO (Not Occurring)

Fugitive CO_2 from Injection and Storage

GHGRP reporters provide an estimate of fugitive emissions from CO_2 injection, assumed to be reported under CO_2 equipment leaks as part of the Geological Sequestration of Carbon Dioxide source category of the GHGRP (40 CFR Part 98, Subpart RR, also referred to as "Subpart RR"), as shown in Table 3-98 (EPA 2024b). This information was used to estimate national emissions associated with CO_2 injection in the *Inventory*. The GHGRP data include injection related emissions from the equipment between the flow meter used to measure injection quantity and the injection wellhead which would be included in the *Inventory*. Any fugitive CO_2 emission between the capture facility fence line and the injection point would not be captured using this method, but would be captured as part of transport emissions discussed above.

GHGRP reporters also provide an estimate of storage and any measured leakage of CO_2 from storage, assumed to be under CO_2 surface leaks in subpart RR reporting as shown in Table 3-98, which has been incorporated into the *Inventory* as well. GHGRP reporters report the annual mass of CO_2 that is emitted by surface leakage as appropriate in accordance with their approved monitoring, reporting, and verification (MRV) plan.[81]

As with transportation emissions, including equipment and surface leakage could potentially overestimate emissions since the amount of captured CO_2 subtraction at the source for the most part (except for NG Processing and petroleum refining) is based on CO_2 sequestered, which already accounts for any equipment or surface losses. However, like for transport emissions, since that value is uncertain, and other sources of CO_2 (e.g., from natural domes) are not being counted, including equipment and surface leaks was deemed appropriate.

[81] Under subpart RR, owners or operators of sequestration facilities submit a proposed MRV plan to EPA who reviews the plan and issues a final MRV plan.

Table 3-98: Emissions from Injection and Storage (kt CO_2)

	1990	2005	2019	2020	2021	2022	2023
CO_2 Injection Leaks	NO	NO	16	13	37	28	31
CO_2 Storage Leaks	NO	NO	0	23	26	23	64

NO (Not Occurring)

CO_2 Sequestration and Capture

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.

GHGRP reporters provide an estimate of CO_2 sequestered under Subpart RR, as shown in Table 3-99. Subpart RR provides a mechanism for facilities to report the amount of CO_2 sequestered in geologic formations on an annual basis to EPA. 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. Facilities measure and report data on the amount of CO_2 received, data used to calculate the amount, and the source of the received CO_2 (if known); various mass balance equation inputs (mass of CO_2 injected, recycled, emitted, produced, equipment leaks, surface leakage, and entrained CO_2 in produced hydrocarbons), the amount of CO_2 sequestered, data used to calculate the inputs/amounts, and an annual monitoring report.

Table 3-99: Sequestered CO_2 (kt CO_2)

	1990	2005	2019	2020	2021	2022	2023
CO_2 Sequestered	NO	NO	8,332	6,802	6,952	8,053	16,299

NO (Not Occurring)

CO_2 sequestered is allocated to its source directly if known based on subpart RR. If the source is unknown or if multiple sources are listed in Subpart RR, CO_2 sequestered is allocated across sources based on subpart PP data. This mainly applies to splitting between natural domes and industrial sources, and in particular natural gas processing. For facilities with annual CO_2 sourced from both CO_2 production wells and natural gas processing, CO_2 was split between the two sources based on subpart PP enhanced oil recovery (EOR) data, as shown in Table 3-100 (EPA 2024a). The kt of CO_2 data is the amount of CO_2 produced (natural domes) transferred to EOR and the amount of CO_2 captured (industrial sources) transferred to EOR. Transfer to EOR is used since that is felt to best represent CO_2 supplied for sequestration.

Under subpart PP, EPA receives data from facilities with CO_2 production wells (natural CO_2 domes) and other industrial facilities that extract or capture CO_2 streams. Importers and exporters of bulk CO_2 are also required to report if total combined imports/exports of CO_2 and other greenhouse gases exceed 25,000 tons CO_2 Eq. per year. Reporters provide information on the mass of CO_2 captured or extracted, data used to calculate that amount, and information on the amount of CO_2 that is supplied to various end use categories. The amount of CO_2 captured by a specific facility is classified as confidential business information (CBI) under the GHGRP and therefore only aggregated data is available for use within the Inventory. Note that Subpart PP data does not include captured CO_2 if it is used on-site. Data is available on the types and number of facilities that capture CO_2 and that was used to determine the source categories of CO_2 capture as shown in Table 3-96.

For facilities with annual CO_2 sourced from CO_2 production wells, natural gas processing, and ethanol plants, CO_2 was first split between natural domes (CO_2 production wells) and industrial capture (natural gas processing and ethanol plants) based on Subpart PP EOR data. Then, industrial capture was spilt evenly between natural gas processing and ethanol plants.

Table 3-100: Percentage of CO_2 (kt) Supplied to EOR from Different Sources

	1990	2005	2019	2020	2021	2022	2023
CO_2 Extracted (domes) for EOR							
kt of CO_2	NO	NO	37,425	25,290	24,987	26,739	25,092
% of Total	NO	NO	72%	72%	71%	73%	74%
CO_2 Captured (industrial) for EOR							
kt of CO_2	NO	NO	14,700	9,910	10,100	9,980	8,660
% of Total	NO	NO	28%	28%	29%	27%	26%
Total	**NO**	**NO**	**52,125**	**35,200**	**35,087**	**36,719**	**33,752**

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

Based on this methodology, sequestered CO_2 was allocated across the different possible source categories, as shown in Table 3-96.

Treatment of EOR in the Inventory

The process of EOR can lead to incidental storage of CO_2 that is received for injection (i.e., storage is not the main goal of EOR). In an EOR project, a portion of the injected CO_2 gets trapped in the reservoir in the form of one or more CO_2 trapping mechanisms (stratigraphic trapping, dissolution in residual oil/brine, residual trapping due to hysteresis, and mineral trapping). The remaining portion of the CO_2 is produced along with hydrocarbons and brine through the production wells, which will be separated and re-injected back into the reservoir along with newly received CO_2. Volumes of CO_2 that are recycled at the last stage of the EOR project can be re-injected back into the reservoir as wells are shut-in or could be transported to another EOR project.

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.

More data on EOR may become available in the future through GHGRP subpart VV (see the Planned Improvements section below).

Uncertainty

A quantitative uncertainty analysis was conducted for CO_2 capture and sequestration using the IPCC-recommended Approach 2 uncertainty estimation methodology. This analysis utilized the Monte Carlo stochastic simulation software @Risk to estimate the 95 percent confidence bound around total CO_2 emissions.

There are uncertainties in pipeline emissions, equipment leakage, and surface leakage. A normal distribution was assumed for all 13 input variables (two for pipeline emissions, seven for equipment leakage, and four for surface leakage.) For these variables, the uncertainty ranges were assigned to the input variables based on IPCC default uncertainty estimates (IPCC 2006) and expert opinion (ICF 2025).

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-101. Total emissions associated with CCS were estimated to be between 47.7 and 147.0 kt CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 51 percent below to 51 percent above the 2023 emission estimate of 97.6 kt CO_2 Eq.

Table 3-101: Approach 2 Quantitative Uncertainty Estimates for CO_2 Emissions from TIGS (kt CO_2 Eq. and Percent)

Source	Gas	2023 Emission Estimate (kt CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a]			
			(kt CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Total Emissions from TIGS	CO_2	97.6	47.7	147.0	-51%	+51%

[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 CO_2 emission estimates from TIGS, 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 from TIGS in the United States.

More details on the monitoring and QA/QC methods applicable to the GHGRP data used can be found under the regulation (40 CFR Part 98).[82] EPA verifies annual facility-level GHGRP reports through a multi-step process (e.g., combination of electronic checks and manual reviews) to identify potential errors and ensure that data submitted to EPA are accurate, complete, and consistent.[83] Based on the results of the verification process, EPA follows up with facilities to resolve mistakes that may have occurred. The post-submittals checks are consistent with a number of general and category-specific QC procedures, including range checks, statistical checks, algorithm checks, and year-to-year checks of reported data and emissions.

[82] See http://www.ecfr.gov/cgi-bin/text-idx?tpl=/ecfrbrowse/Title40/40cfr98_main_02.tpl.

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

Recalculation Discussion

No recalculations were performed for the current *Inventory*.

Planned Improvements

EPA updated the GHGRP rules to add a new subpart VV (40 CFR Part 98 Subpart VV). Subpart VV creates a reporting pathway for EOR operators who use the ISO 27916:2019 standard (ISO standard) to quantify the CO_2 sequestered as a result of their operations. The ISO standard has requirements similar to the site-specific monitoring, reporting and verification (MRV) plan required in order to report geologic sequestration under subpart RR. When EOR facilities start to report using subpart VV facilities, that would help to update treatment of CO_2 captured for EOR in the *Inventory*. Data on CO_2 sequestered under subpart VV could be treated in the *Inventory* in the same way as the subpart RR data.

EPA also updated the GHGRP rules to add subpart PP data reporting requirements, that if a CO_2 stream is captured from any facility subject to 40 CFR part 98 as well as supplying to RR or VV facilities , they must:

1. Report the facility identification number associated with the annual greenhouse gas report for the Subpart PP facility;
2. Report each facility identification number associated with the annual greenhouse gas reports for each Subpart RR or VV facility to which CO_2 is transferred; and
3. Report the annual quantity of CO_2 in metric tons that is transferred to each Subpart RR or VV facility.

This provides a more direct link between carbon capture and sequestration in terms of *Inventory* adjustments. This would include CO_2 captured at direct air capture (DAC) facilities in the future. To prevent double counting, the updates also clarify that wells reported under subpart RR or VV should not also be counted under Subpart UU.

Furthermore, there could be additional existing GHGRP data available that could provide more input to refine the allocation process. For example, subpart PP reporters track and report biogenic and fossil CO_2 separately. That information could be used to help allocate CO_2 from the different capture sources to end uses based on assumptions about the biogenic content of captured CO_2. This data has not yet been incorporated but could be used to help allocate capture and sequestration in the future.

Currently, there are no data included in this memo regarding CO_2 sequestered in years prior to 2010. Alternate data sources could be explored, including reported quantities from the Regional Carbon Sequestration Partnerships (RCSPs). Data would need to be available on an annual basis to consider for conclusion.

Other possible updates include the treatment of exported CO_2. Exported CO_2 is currently accounted for by adjusting down the amount of fuel combustion to net out emission results. Exported CO_2 could be more explicitly accounted for in the *Inventory* through reporting CO_2 capture from the energy use industrial sector and reporting the quantity of CO_2 export as part of the CO_2 TIGS accounting.

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

Emissions resulting from the combustion of fuels used for international transport activities, termed international bunker fuels, 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, reflect 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).

Two transport modes are addressed under the IPCC definition of international bunker fuels: aviation and marine.[84] 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.[85]

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.

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84 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).

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

Two main types of fuels are used on sea-going vessels: distillate diesel fuel and residual fuel oil. Carbon dioxide is the primary greenhouse gas emitted from marine shipping.

Overall, aggregate greenhouse gas emissions in 2023 from the combustion of international bunker fuels from both aviation and marine activities were 97.0 MMT CO_2 Eq., or 7.2 percent below emissions in 1990 (see Table 3-102 and Table). Emissions from international flights and international shipping voyages departing from the United States have increased by 74.1 percent and decreased by 54.7 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.

For this *Inventory*, 2023 marine and military bunker fuel data were available, however civilian aviation bunker fuel data were not available and were proxied based on 2022 values.

Table 3-102: CO_2, CH_4, and N_2O Emissions from International Bunker Fuels (MMT CO_2 Eq.)

Gas/Mode	1990	2005	2019	2020	2021	2022	2023
CO_2	103.6	113.3	113.6	69.6	80.2	98.2	96.2
Aviation	38.2	60.2	78.3	39.8	50.8	66.6	66.5
Commercial	*30.0*	*55.6*	*75.1*	*36.7*	*47.6*	*63.5*	*63.5*
Military	*8.2*	*4.6*	*3.2*	*3.1*	*3.2*	*3.1*	*3.0*
Marine	*65.4*	*53.1*	*35.4*	*29.9*	*29.4*	*31.6*	*29.6*
CH_4	0.2	0.1	0.1	0.1	0.1	0.1	0.1
Aviation	NO	NO	NO	NO	NO	NO	NO
Marine	0.2	0.1	0.1	0.1	0.1	0.1	0.1
N_2O	0.8	0.9	0.9	0.5	0.6	0.8	0.8
Aviation	0.3	0.5	0.7	0.3	0.4	0.6	0.6
Marine	0.4	0.4	0.2	0.2	0.2	0.2	0.2
Total	**104.6**	**114.3**	**114.6**	**70.3**	**80.9**	**99.1**	**97.0**

NO (Not Occurring)
Notes: Totals may not sum due to independent rounding. Includes aircraft cruise altitude emissions. Civilian aviation bunker fuel data were not available and were proxied based on 2022 values.

Table 3-103: CO_2, CH_4, and N_2O Emissions from International Bunker Fuels (kt)

Gas/Mode	1990	2005	2019	2020	2021	2022	2023
CO_2	**103,634**	**113,328**	**113,632**	**69,638**	**80,180**	**98,241**	**96,160**
Aviation	38,205	60,221	78,280	39,781	50,812	66,646	66,526
Marine	65,429	53,107	35,351	29,857	29,369	31,595	29,634
CH_4	**7**	**5**	**4**	**3**	**3**	**3**	**3**
Aviation	NO	NO	NO	NO	NO	NO	NO
Marine	7	5	4	3	3	3	3
N_2O	**3**	**3**	**3**	**2**	**2**	**3**	**3**
Aviation	1	2	2	1	2	2	2
Marine	2	1	1	1	1	1	1

NO (Not Occurring)
Notes: Totals may not sum due to independent rounding. Includes aircraft cruise altitude emissions. Civilian aviation bunker fuel data were not available and were proxied based on 2022 values.

Methodology and Time-Series Consistency

Emissions of CO_2 were for the most part estimated by applying carbon content and fraction oxidized factors to fuel consumption activity data. This approach is analogous to that described under Section 3.1. Carbon content and fraction oxidized factors for jet fuel (except for commercial aviation as per below), 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 ASTM (1989) and USAF (1998). Heat content for distillate fuel oil and residual fuel oil were taken from EIA (2025) and USAF (1998), and heat content for jet fuel was taken from EIA (2025). See below for details on how emission estimates for commercial aviation were determined.

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 2022 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 2022 were obtained directly from FAA's AEDT model (FAA 2024), data for 2023 was not yet available and has been proxied to 2022 in the current *Inventory*. The radar-informed method that was used to estimate CO_2 emissions for commercial aircraft for 1990 and 2000 through 2022 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 2025). 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 . See Annex 3.8 for additional discussion of military data.

Table 3-104: Aviation Jet Fuel Consumption for International Transport (TBtu)

Nationality	1990	2005	2019	2020	2021	2022	2023
U.S. and Foreign Carriers	426	791	1,068	521	677	902	902
U.S. Military	116	64	44	43	44	44	42
Total	**542**	**854**	**1,112**	**564**	**721**	**946**	**944**

Note: Totals may not sum due to independent rounding. Civilian aviation bunker fuel data were not available and were proxied based on 2022 values.

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 2023) for 1990 through 2001, 2007 through 2023, 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 (2025). 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 .

Table 3-105: Marine Fuel Consumption for International Transport (Million Gallons)

Fuel Type	1990	2005	2019	2020	2021	2022	2023
Residual Fuel Oil	4,781	3,881	2,246	1,964	1,953	2,172	2,016
Distillate Diesel Fuel & Other	617	444	702	461	437	435	423
U.S. Military Naval Fuels	522	471	281	296	285	263	255
Total	**5,920**	**4,796**	**3,229**	**2,721**	**2,674**	**2,870**	**2,694**

Note: Totals may not sum due to independent rounding.

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990 through 2023.

Uncertainty

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.[86] 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 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 2023, 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

[86] See uncertainty discussions under section 3.1 CO_2 from Fossil Fuel Combustion.

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.[87]

There is also concern regarding the reliability of the existing DOC (1991 through 2024) data on marine vessel fuel consumption reported at U.S. customs stations due to the significant degree of inter-annual variation.

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.

Recalculations Discussion

No recalculations were performed for the current *Inventory*.

Planned Improvements

EPA will evaluate data availability to update the sources for densities, energy contents, and emission factors applied to estimate emissions from aviation and marine fuels. Many are from sources from the late 1990s, such as IPCC/UNEP/OECD/IEA (1997). Potential sources with more recent data include the International Maritime Organization (IMO) greenhouse gas emission inventory, International Air Transport Association (IATA)/ICAO greenhouse gas reporting system (CORSIA), and the EPA Greenhouse Gas Reporting Program (GHGRP) Technical Support Document for Petroleum Products. Specifically, EPA will evaluate data availability to support updating the heat contents and carbon contents of jet fuel with input from EIA.

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 IMO greenhouse gas emission inventory, data from the U.S. Coast Guard on vehicle operation currently used in criteria pollutant modeling, data from the International Energy Agency (IEA), relevant updated FAA models to improve aviation bunker fuel estimates, and researching newly available marine bunker data.

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[87] U.S. aviation emission estimates for CO, NO_x, and NMVOCs are reported by EPA's National Emission Inventory (NEI) Air Pollutant Emission Trends website, and reported under the Mobile Combustion section. It should be noted that these estimates are based solely upon LTO cycles and consequently only capture near ground-level emissions, which are more relevant for air quality evaluations. These estimates also include both domestic and international flights. Therefore, estimates reported under the Mobile Combustion section overestimate IPCC-defined domestic CO, NO_x, and NMVOC emissions by including landing and take-off (LTO) cycles by aircraft on international flights, but underestimate because they do not include emissions from aircraft on domestic flight segments at cruising altitudes.

3.11 Biomass and Biofuels Consumption (Source Category 1A)

The combustion of biomass—such as wood, charcoal, the biogenic portions of MSW, and wood waste and biofuels 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 IPCC guidelines, CO_2 emissions from biomass and biofuel 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 carbon 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 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 biomass and biofuels consumption.

In 2023, total CO_2 emissions from the burning of woody biomass in the industrial, residential, commercial, and electric power sectors were approximately 187.7 MMT CO_2 Eq. (187,690 kt) (see Table 3-106 and Table 3-107). As the largest consumer of woody biomass, the industrial sector was responsible for 61.8 percent of the CO_2 emissions from this source. The residential sector was the second largest emitter, constituting 24.7 percent of the total, while the electric power and commercial sectors accounted for the remainder.

Table 3-106: CO_2 Emissions from Wood Consumption by End-Use Sector (MMT CO_2 Eq.)

End-Use Sector	1990	2005	2019	2020	2021	2022	2023
Industrial	135.3	136.3	132.1	127.3	128.2	122.8	115.9
Residential	59.8	44.3	56.3	35.6	35.5	43.6	46.4
Commercial	6.8	7.2	7.7	7.5	7.5	7.5	7.4
Electric Power	13.3	19.1	20.7	19.1	20.3	20.4	17.9
Total	**215.2**	**206.9**	**216.7**	**189.5**	**191.5**	**194.3**	**187.7**

Note: Totals may not sum due to independent rounding.

Table 3-107: CO_2 Emissions from Wood Consumption by End-Use Sector (kt)

End-Use Sector	1990	2005	2019	2020	2021	2022	2023
Industrial	135,348	136,269	132,069	127,301	128,209	122,843	115,905
Residential	59,808	44,340	56,251	35,585	35,484	43,565	46,436
Commercial	6,779	7,218	7,654	7,515	7,490	7,525	7,399
Electric Power	13,252	19,074	20,677	19,115	20,288	20,385	17,950
Total	**215,186**	**206,901**	**216,652**	**189,516**	**191,471**	**194,318**	**187,690**

Note: Totals may not sum due to independent rounding.

Carbon dioxide emissions from combustion of the biogenic components of MSW by the electric power sector were an estimated 13.9 MMT CO_2 (13,936 kt) in 2023. Emissions across the time series are shown in Table 3-108 and Table 3-109. As discussed in Section 3.3, MSW is combusted to produce electricity and the CO_2 emissions from the fossil portion of the MSW (e.g., plastics, textiles, etc.) are included in the energy sector FFC estimates. The MSW also includes biogenic components (e.g., food waste, yard trimmings, natural fibers) and the CO_2 emissions associated with that biogenic portion is included here.

Table 3-108: CO_2 Emissions from Biogenic Components of MSW (MMT CO_2 Eq.)

End-Use Sector	1990	2005	2019	2020	2021	2022	2023
Electric Power	18.5	14.7	15.7	15.6	15.3	14.9	13.9

Table 3-109: CO_2 Emissions from Biogenic Components of MSW (kt)

End-Use Sector	1990	2005	2019	2020	2021	2022	2023
Electric Power	18,534	14,722	15,709	15,614	15,329	14,864	13,936

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 2023, the United States transportation sector consumed an estimated 1,116.4 trillion Btu of ethanol (95 percent of total), and as a result, produced approximately 76.4 MMT CO_2 Eq. (76,427 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	2019	2020	2021	2022	2023
Transportation[a]	4.1	21.6	78.7	68.1	75.4	75.0	76.4
Industrial	0.1	1.2	1.6	1.6	1.5	1.8	1.7
Commercial	0.1	0.2	2.2	2.2	2.1	2.8	2.6
Total	**4.2**	**22.9**	**82.6**	**71.8**	**79.1**	**79.6**	**80.7**

[a] See Annex 3.2, Table A-71 for additional information on transportation consumption of these fuels.
Note: Totals may not sum due to independent rounding.

Table 3-111: CO_2 Emissions from Ethanol Consumption (kt)

End-Use Sector	1990	2005	2019	2020	2021	2022	2023
Transportation[a]	4,059	21,616	78,739	68,085	75,417	74,953	76,427
Industrial	105	1,176	1,610	1,582	1,509	1,790	1,652
Commercial	63	151	2,229	2,182	2,139	2,850	2,629
Total	**4,227**	**22,943**	**82,578**	**71,848**	**79,064**	**79,593**	**80,708**

[a] See Annex 3.2, Table A-71 for additional information on transportation consumption of these fuels.
Note: Totals may not sum due to independent rounding.

The transportation sector is assumed to be responsible for all of the biodiesel consumption in the United States (EIA 2025). 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 2024).

In 2023, the United States consumed an estimated 246.3 trillion Btu of biodiesel, and as a result, produced approximately 18.2 MMT CO_2 Eq. (18,185 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 2024). There was no measured biodiesel consumption prior to 2001 EIA (2025).

Table 3-112: CO_2 Emissions from Biodiesel Consumption (MMT CO_2 Eq.)

End-Use Sector	1990	2005	2019	2020	2021	2022	2023
Transportation[a]	NO	0.9	17.1	17.7	16.1	15.6	18.2

NO (Not Occurring)
[a] See Annex 3.2, Table A-71 for additional information on transportation consumption of these fuels.

Table 3-113: CO_2 Emissions from Biodiesel Consumption (kt)

End-Use Sector	1990	2005	2019	2020	2021	2022	2023
Transportation[a]	NO	856	17,080	17,678	16,112	15,622	18,185

NO (Not Occurring)
[a] See Annex 3.2, Table A-71 for additional information on transportation consumption of these fuels.

Methodology and Time-Series Consistency

Woody biomass emissions were estimated by applying two gross heat contents from EIA (Lindstrom 2006) to U.S. consumption data (EIA 2025) (see Table 3-115), 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.

Data for total waste incinerated, excluding tires, from 1990 to 2023 was derived following the methodology described in Section 3.3. Biogenic CO_2 emissions associated with MSW combustion were obtained from EPA's GHGRP FLIGHT data for MSW combustion sources (EPA 2023). Dividing biogenic CO_2 emissions from GHGRP FLIGHT data for MSW combustors by estimated MSW tonnage combusted yielded an annual biogenic CO_2 emission factor. This approach follows the same approach used to develop the fossil CO_2 emissions from MSW combustion as discussed in Section 3.3. As this data was only available following 2011, all years prior use an average of the emission factors from 2011 through 2015.

Biogenic CO_2 emissions from MSW combustion were calculated by multiplying the annual tonnage estimates, excluding tires, by the calculated emissions factor. Calculated biogenic CO_2 emission factors are shown in Table 3-114.

Table 3-114: Calculated Biogenic CO_2 Content per Ton Waste (kg CO_2/Short Ton Combusted)

End-Use Sector	1990	2005	2019	2020	2021	2022	2023
CO_2 Emission Factors	556	556	558	566	550	564	543

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 (2025) 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 3-116). 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 2025) (see Table 3-117).[88]

Table 3-115: Woody Biomass Consumption by Sector (Trillion Btu)

End-Use Sector	1990	2005	2019	2020	2021	2022	2023
Industrial	1,441.9	1,451.7	1,407.0	1,356.2	1,365.9	1,308.7	1,234.8
Residential	580.0	430.0	545.5	345.1	344.1	422.5	450.3
Commercial	65.7	70.0	74.2	72.9	72.6	73.0	71.8
Electric Power	128.5	185.0	200.5	185.4	196.7	197.7	174.1
Total	**2,216.2**	**2,136.7**	**2,227.2**	**1,959.5**	**1,979.4**	**2,001.8**	**1,930.9**

Note: Totals may not sum due to independent rounding.

Table 3-116: Ethanol Consumption by Sector (Trillion Btu)

End-Use Sector	1990	2005	2019	2020	2021	2022	2023
Transportation	59.3	315.8	1,150.2	994.6	1,101.7	1,094.9	1,116.4
Industrial	1.5	17.2	23.5	23.1	22.0	26.2	24.1
Commercial	0.9	2.2	32.6	31.9	31.2	41.6	38.4
Total	**61.7**	**335.1**	**1,206.3**	**1,049.5**	**1,155.0**	**1,162.7**	**1,179.0**

Note: Totals may not sum due to independent rounding.

Table 3-117: Biodiesel Consumption by Sector (Trillion Btu)

End-Use Sector	1990	2005	2019	2020	2021	2022	2023
Transportation	NO	11.6	231.3	239.4	218.2	211.6	246.3

NO (Not Occurring)

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990 through 2023.

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[88] CO_2 emissions from biodiesel do not include emissions associated with the carbon 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.

Uncertainty

An uncertainty analysis was conducted for biomass and biofuel combustion using the IPCC-recommended Approach 2 uncertainty estimation methodology. This analysis utilized the Monte Carlo stochastic simulation software @RISK to estimate the 95 percent confidence bound around total biomass and biofuel combustion emissions.

There are uncertainties in ethanol consumption, biodiesel consumption, woody biomass consumption, and CO_2 emissions from waste incineration. It is assumed that the biodiesel and ethanol reported is 100 percent biodiesel rather than a blend. A normal distribution was assumed for all ethanol consumption, wood consumption, and MSW input variables, while a uniform distribution was assumed for the biodiesel emission factor. For these variables, the uncertainty ranges were assigned to the input variables based on IPCC default uncertainty estimates (IPCC 2006) and expert opinion (ICF 2025).

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-101. Biomass and biofuel combustion CO_2 emissions in 2023 were estimated to be between 272.1 and 335.5 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 9 percent below to 12 percent above the 2023 emission estimate of 300.5 MMT CO_2 Eq.

Table 3-118: Approach 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Biomass and Biofuel Combustion (MMT CO_2 Eq. and Percent)

Source	Gas	2023 Emission Estimate (MMT CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a]			
			(MM CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Biomass and Biofuel Combustion	CO_2	300.5	272.1	335.5	-9%	+12%

Recalculations Discussion

EIA (2025) updated electricity statistics which affected commercial sector wood consumption for the years 2014 through 2022. This caused CO_2 emissions from commercial wood to decrease by an annual average of 0.9 MMT CO_2 Eq. (11percent) for the years 2014 and 2022, compared to estimates in the previous *Inventory*.

EIA (2025) also updated ethanol consumed by all sectors in 2022, which caused CO_2 emissions from industrial ethanol to decrease by 0.13 MMT CO_2 Eq. (6.7 percent), CO_2 emissions from transportation ethanol to decrease by less than 0.05 MMT CO_2 Eq. (less than 0.05 percent), and CO_2 emissions from commercial ethanol to increase by 0.13 MMT CO_2 Eq. (4.7 percent), compared to the previous *Inventory*.

Planned Improvements

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

Currently, emission estimates from biomass and biomass-based fuels included in this *Inventory* are limited to woody biomass, biogenic components of MSW, ethanol, and biodiesel. Additional forms of biomass-based fuel consumption include biogas, renewable diesel and other biofuels. EPA will investigate additional forms of biomass-based fuel consumption, research the availability of relevant emissions factors, and integrate these into the *Inventory* as feasible. EPA will examine EIA data on biogas and other biofuels to see if these fuel types can be included in future Inventories. EIA (2024a) 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 renewable diesel fuels as well as biodiesel.

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, although 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 in this chapter, some facility-level fuel combustion emissions reported under EPA's GHGRP may also include industrial process emissions.

In line with IPCC guidelines, fuel combustion emissions are included in this chapter, while process emissions are included in the Industrial Processes and Product Use chapter of this report. In examining data from EPA's GHGRP that would be useful to improve the emission estimates for the CO_2 from biomass combustion category, particular attention will also be made to ensure time-series consistency, as the facility-level reporting data from EPA's GHGRP are not available for all inventory years as reported in this *Inventory*. Additionally, analyses will focus on aligning reported facility-level fuel types and IPCC fuel types per the national energy statistics, ensuring CO_2 emissions from biomass are separated in the facility-level reported data, and maintaining consistency with national energy statistics provided by EIA. In implementing improvements and integration of data from EPA's GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will be relied upon.[89]

Lastly, the CO_2 emission factor for wood developed by NESCAUM (2024) will be reviewed and potentially incorporated based on this review.

3.12 Energy Sources of Precursor Greenhouse Gases

In addition to the main greenhouse gases addressed above, energy-related activities are also sources of greenhouse gas precursors. This section summarizes information on precursor emissions, which include carbon monoxide (CO), nitrogen oxides (NO_x), non-methane volatile organic compounds (NMVOCs), ammonia (NH_3), and sulfur dioxide (SO_2). These gases are not direct greenhouse gases, but indirectly impact Earth's radiative balance by altering the concentrations of greenhouse gases (e.g., tropospheric ozone) and atmospheric aerosol (e.g., particulate sulfate). Total emissions of NO_x, CO, NMVOCs, NH_3 ,and SO_2 from energy-related activities from 1990 to 2023 are reported in Table 3-119.

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

Table 3-119: NO_x, CO, NMVOC, NH_3, and SO_2 Emissions from Energy-Related Activities (kt)

Gas/Activity	1990	2005	2019	2020	2021	2022	2023
NO_x	**21,805**	**18,760**	**6,986**	**6,181**	**6,243**	**6,045**	**5,765**
Fossil Fuel Combustion	21,678	18,188	6,496	5,626	5,557	5,405	5,125
Transportation[a]	12,132	12,628	4,322	3,618	3,543	3,375	3,195
Industrial	2,475	1,486	800	753	720	727	730
Electric Power Sector	6,045	3,440	898	761	806	778	676
Commercial	451	288	187	192	188	206	206
Residential	575	346	290	300	300	318	318
Petroleum and Natural Gas Systems	127	572	491	556	685	640	640
International Bunker Fuels	1,953	1,699	1,280	977	1,008	1,132	1,077
CO	**124,583**	**64,319**	**30,258**	**28,316**	**28,704**	**27,889**	**27,360**
Fossil Fuel Combustion	124,351	63,686	29,660	27,706	28,073	27,213	26,685
Transportation[a]	119,478	59,540	25,621	23,546	23,889	23,003	22,526
Residential	3,620	2,393	2,860	2,968	2,950	2,960	2,960
Industrial	704	976	600	673	659	659	658
Electric Power Sector	329	582	428	361	423	422	371
Commercial	220	195	151	157	153	169	169
Petroleum and Natural Gas Systems	232	632	599	610	630	676	676
International Bunker Fuels	102	131	150	83	101	128	127
NMVOCs	**12,269**	**8,081**	**4,987**	**4,822**	**5,167**	**5,045**	**4,914**
Fossil Fuel Combustion	11,793	6,079	2,593	2,391	2,454	2,329	2,198
Transportation[a]	10,932	5,608	2,072	1,846	1,912	1,786	1,655
Residential	693	322	397	431	429	429	429
Commercial	9	18	14	14	14	14	14
Industrial	117	87	81	74	73	74	74
Electric Power Sector	43	44	29	26	27	27	27
Petroleum and Natural Gas Systems	476	2,002	2,394	2,431	2,713	2,716	2,716
International Bunker Fuels	57	54	45	32	34	40	38
NH_3	**190**	**218**	**177**	**178**	**265**	**269**	**266**
Fossil Fuel Combustion	190	218	177	178	265	266	262
Transportation	169	153	96	84	171	172	168
Residential	4	17	52	63	63	66	66
Commercial	2	5	2	2	2	2	2
Industrial	15	20	12	13	13	12	12
Electric Power Sector	0	23	16	17	17	15	15
Petroleum and Natural Gas Systems	+	+	+	+	+	4	4
International Bunker Fuels	NA	NA	NA	NA	NA	NA	NA
SO_2	**21,638**	**13,331**	**1,509**	**1,289**	**1,423**	**1,422**	**1,230**
Fossil Fuel Combustion	21,482	13,235	1,447	1,139	1,273	1,143	951
Electric Power Sector	14,432	9,436	921	758	898	819	627
Industrial	2,886	1,378	234	173	169	143	142
Transportation[a]	793	724	40	23	24	26	26
Commercial	485	318	19	13	14	14	14
Residential	2,886	1,378	234	173	169	143	142
Petroleum and Natural Gas Systems	156	96	61	150	150	279	279
International Bunker Fuels	NA	NA	NA	NA	NA	NA	NA

NA (Not Applicable)

[a] The scope of the NEI for aircraft related precursor emissions included under the transportation is different from the *Inventory* reporting scope. The NEI precursor estimate methodology does not exclude emissions that could be considered international bunkers given local impacts from these emissions. The precursor estimates are modeled using FAA- and state-supplied landing

and take-off data for all aircraft types (including ground support equipment and auxiliary engines) used for public, private, and military purposes.
Note: Totals may not sum due to independent rounding.
Source: (EPA 2023a). Emission categories from EPA (2023) are aggregated into sectors and categories reported as shown in Table ES-3.

Methodology and Time-Series Consistency

Emission estimates for 1990 through 2023 were obtained from data published on the National Emissions Inventory (NEI) Air Pollutant Emissions Trends Data website (EPA 2024). For Table 3-119, NEI reported emissions of CO, NO_x, NMVOCs, NH_3, and SO_2 were recategorized from NEI Emissions Inventory System (EIS) sectors to source categories more closely aligned with sectors and categories in this report, based on discussions between the EPA *Inventory* and NEI staff (see crosswalk documented in Annex 6.3).[90] EIS sectors mapped to the energy sector categories in this report include: fuel combustion for electric utilities, industrial, and other; petroleum and related industries; highway vehicles; off-highway; and other mobile sources (e.g., commercial marine vessels and rail). As described in the NEI Technical Support Documentation (TSD) (EPA 2023b), NEI emissions are estimated through a combination of emissions data submitted directly to the EPA by state, local, and tribal air agencies, as well as additional information added by the Agency from EPA emissions programs, such as the emission trading program, Toxics Release Inventory (TRI), and data collected during rule development or compliance testing.

Methodological approaches were applied to the entire time series to ensure time-series consistency from 1990 through 2022, which are described in detail in the NEI's TSD and on EPA's Air Pollutant Emission Trends website (EPA 2023b; EPA 2024). No quantitative estimates of uncertainty were calculated for this source category.

[90] The NEI estimates and reports emissions from six criteria air pollutants (CAPs) and 187 hazardous air pollutants (HAPs) in support of National Ambient Air Quality Standards. EPA reported CAP emission trends are grouped into 60 sectors and 15 Tier 1 source categories, which broadly cover similar source categories to those presented in this chapter. For reporting precursor emissions in the common data tables, EPA has mapped and regrouped emissions of greenhouse gas precursors (CO, NO_x, SO_2, and NMVOCs) from NEI's EIS sectors to better align with NIR source categories, and to ensure consistency and completeness to the extent possible. See Annex 6.3 for more information on this mapping.