

3 Energy

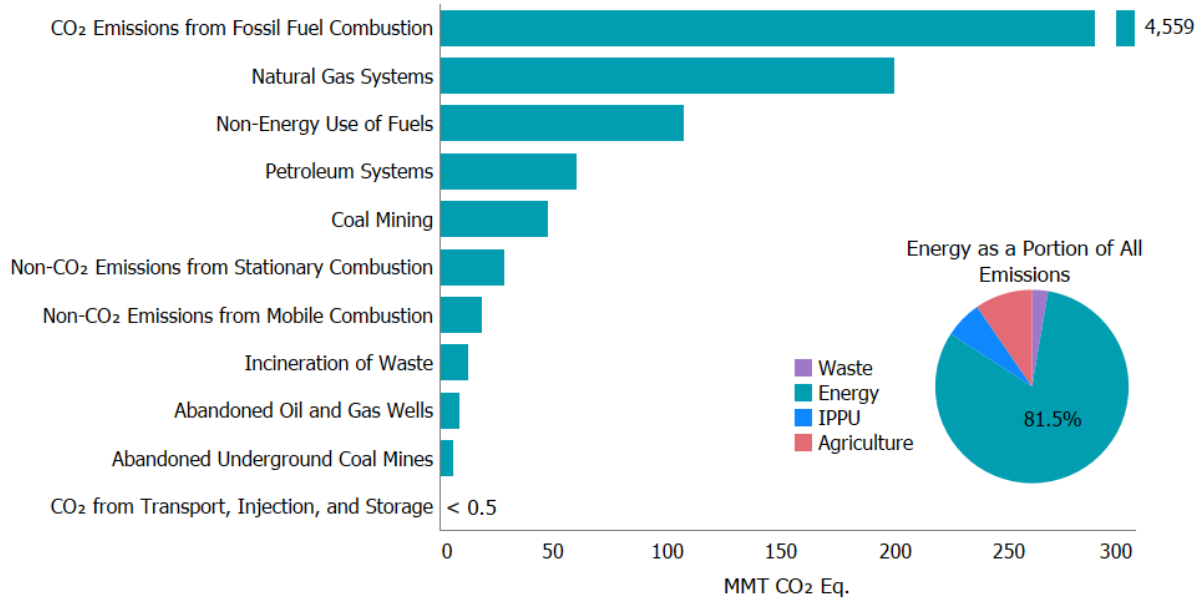
Energy-related activities were the primary sources of U.S. anthropogenic greenhouse gas emissions, accounting for 81.5 percent of total gross greenhouse gas emissions on a carbon dioxide (CO₂) equivalent basis in 2023.¹ This included 96.4, 39.5, and 9.3 percent of the nation’s CO₂, methane (CH₄), and nitrous oxide (N₂O) emissions, respectively.² Energy-related CO₂ emissions alone constituted 76.5 percent of total gross U.S. greenhouse gas emissions from all sources on a CO₂-equivalent basis, while the non-CO₂ emissions from energy-related activities represented a much smaller portion of total gross national emissions (5.0 percent collectively).

Emissions from fossil fuel combustion contribute the vast majority of energy-related emissions, with CO₂ being the primary gas emitted (see Figure 3-1 and Figure 3-2). Globally, approximately 33,809 million metric tons (MMT) of CO₂ 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 CO₂ emissions are considered in more detail than other energy-related emissions in this report (see Figure 3-3).

Fossil fuel combustion also emits CH₄ and N₂O. Stationary combustion of fossil fuels was the third largest source of N₂O emissions in the United States and mobile fossil fuel combustion was the fifth largest source. Energy-related activities other than fuel combustion, such as the production, transmission, storage, and distribution of fossil fuels, also emit greenhouse gases. These emissions consist primarily of fugitive CH₄ emissions from natural gas systems, coal mining, and petroleum systems.

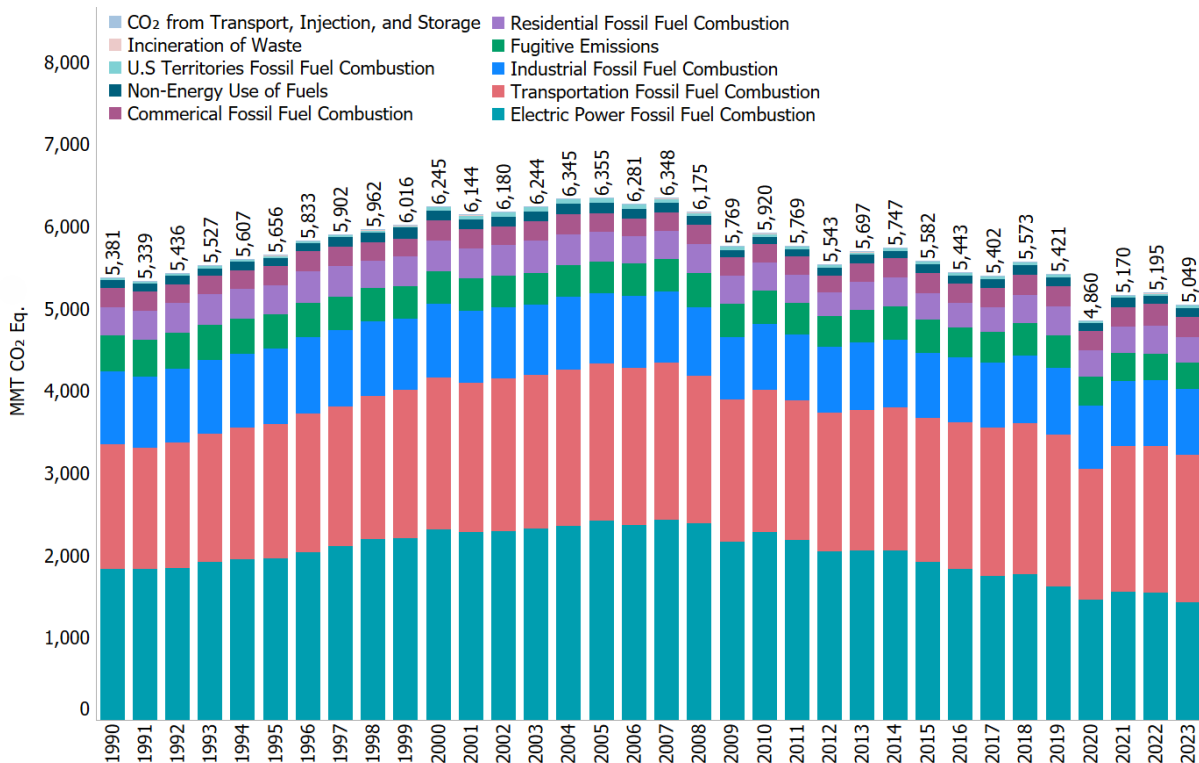
¹ Estimates are presented in units of million metric tons of carbon dioxide equivalent (MMT CO₂ Eq.), which weight each gas by its global warming potential, or GWP, value. See section on global warming potentials in the Executive Summary.
² The contribution of energy non-CO₂ emissions is based on gross totals so excludes LULUCF methane (CH₄) and nitrous oxide (N₂O) emissions. The contribution of energy-related methane (CH₄) and (N₂O) including LULUCF non-CO₂ emissions, is 37.1 percent and 9.8 percent respectively.
³ Global CO₂ emissions from fossil fuel combustion were taken from International Energy Agency *Global energy-related CO₂ emissions, 2023*. Available at: <https://iea.blob.core.windows.net/assets/33e2badc-b839-4c18-84ce-f6387b3c008f/CO2Emissionsin2023.pdf> (IEA 2023).

1 **Figure 3-1: 2023 Energy Sector Greenhouse Gas Sources**



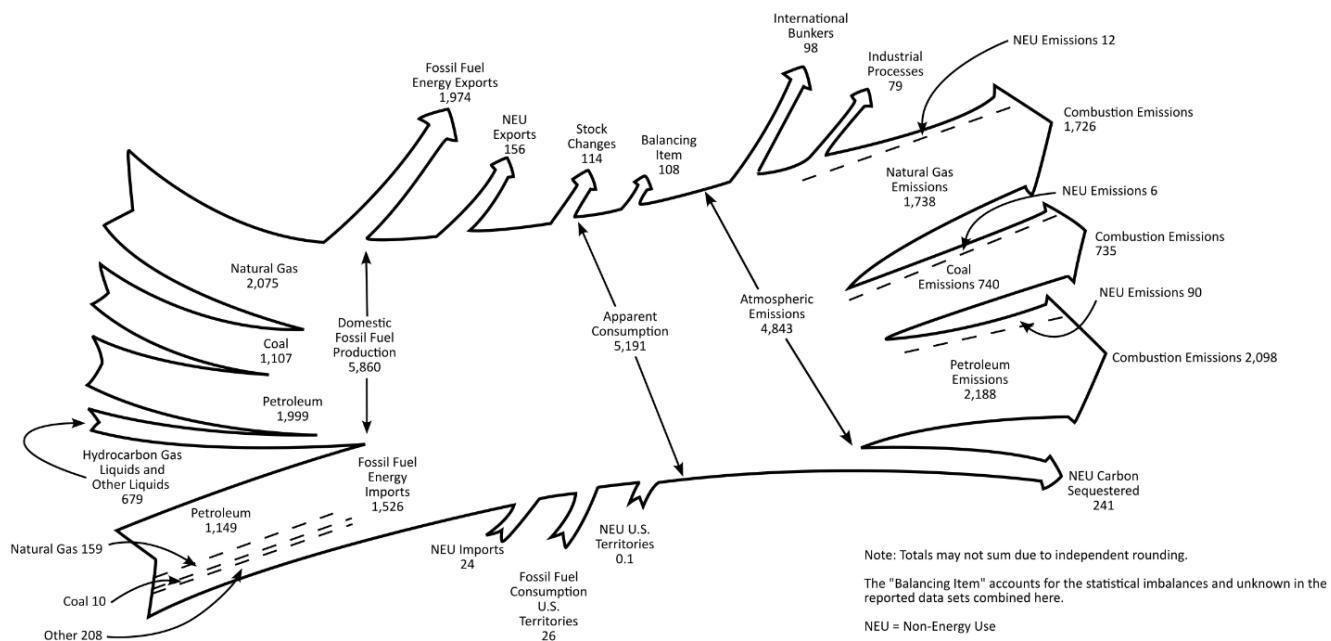
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3 **Figure 3-2: Trends in Energy Sector Greenhouse Gas Sources**



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1 **Figure 3-3: 2023 U.S. Fossil Carbon Flows (MMT CO₂ Eq.)**



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 3 Table 3-1 summarizes emissions from the Energy sector in units of MMT CO₂ Eq., while unweighted gas
 4 emissions in kilotons (kt) are provided in Table 3-2. Overall, emissions due to energy-related activities
 5 were 5,048.6 MMT CO₂ Eq. in 2023,⁴ a decrease of 6.2 percent since 1990 and a decrease of 2.8 percent
 6 since 2022. Trends are driven by a number of factors including a shift from coal to natural gas and
 7 renewables in the electric power sector.

⁴ This Inventory report presents CO₂ equivalent values based on the IPCC *Fifth Assessment Report* (AR5) GWP values. See Chapter 1, Introduction for more information.

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

Gas/Source	1990	2005	2019	2020	2021	2022	2023
CO₂	4,910.9	5,923.1	5,059.2	4,521.1	4,841.2	4,878.0	4,741.33
Fossil Fuel Combustion	4,752.2	5,744.1	4,852.6	4,342.3	4,654.6	4,702.8	4,559.1
<i>Transportation</i>	1,468.9	1,858.6	1,816.6	1,573.0	1,753.5	1,753.6	1,776.2
<i>Electricity Generation</i>	1,820.0	2,400.1	1,606.7	1,439.6	1,540.9	1,531.7	1,414.2
<i>Industrial</i>	876.5	847.6	809.8	763.4	780.5	799.7	792.1
<i>Residential</i>	338.6	358.9	342.9	314.8	318.0	335.2	307.1
<i>Commercial</i>	228.3	227.1	251.7	229.3	237.5	259.2	244.2
<i>U.S. Territories</i>	20.0	51.9	24.8	22.3	24.1	23.5	25.3
Non-Energy Use of Fuels	99.1	125.0	106.5	97.9	111.7	101.9	107.4
Natural Gas Systems	32.4	26.3	38.7	36.8	35.7	36.4	37.6
Petroleum Systems	9.6	10.2	45.4	28.9	24.1	22.0	22.5
Incineration of Waste	12.9	13.3	12.9	12.9	12.5	12.4	12.4
Coal Mining	4.6	4.2	3.0	2.2	2.5	2.5	2.4
CO ₂ Transport, Injection and Geological Storage	0.0	0.0	+	+	0.1	0.1	0.1
Abandoned Oil and Gas Wells	+	+	+	+	+	+	+
<i>Biomass-Wood^a</i>	215.2	206.9	216.7	189.5	191.5	194.3	187.7
<i>International Bunker Fuels^b</i>	103.6	113.3	113.6	69.6	80.2	98.2	96.4
<i>Biofuels-Ethanol^a</i>	4.2	22.9	82.6	71.8	79.1	79.6	80.7
<i>Biofuels-Biodiesel^a</i>	0.0	0.9	17.1	17.7	16.1	15.6	18.2
<i>Biomass-MSW^a</i>	18.5	14.7	15.7	15.6	15.3	14.9	14.9
CH₄	409.8	359.1	320.2	302.0	289.9	277.6	271.06
Natural Gas Systems	219.0	210.6	189.0	180.0	174.7	171.8	162.0
Coal Mining	108.1	71.5	53.0	46.2	44.7	43.6	45.4
Petroleum Systems	50.0	47.4	50.6	50.4	45.2	36.2	37.8
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	2.6
Incineration of Waste	+	+	+	+	+	+	+
<i>International Bunker Fuels^b</i>	0.2	0.1	0.1	0.1	0.1	0.1	0.1
N₂O	60.5	72.9	41.3	37.0	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	18.8	16.1	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	+	+	+	+	+	+	+
<i>International Bunker Fuels^b</i>	0.8	0.9	0.9	0.5	0.6	0.8	0.8
Total	5,381.2	6,355.1	5,420.8	4,860.0	5,170.3	5,195.2	5,048.6

2 + Does not exceed 0.05 MMT CO₂ Eq.

3 ^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.

4 ^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.

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

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

Gas/Source	1990	2005	2019	2020	2021	2022	2023
CO₂	4,910,871	5,923,092	5,059,250	4,521,051	4,841,192	4,878,027	4,741,331
Fossil Fuel Combustion	4,752,234	5,744,138	4,852,647	4,342,309	4,654,629	4,702,769	4,559,052
Non-Energy Use of Fuels	99,104	124,988	106,487	97,889	111,726	101,925	107,355
Natural Gas Systems	32,431	26,321	38,701	36,813	35,740	36,402	37,605
Petroleum Systems	9,589	10,215	45,450	28,874	24,094	22,039	22,458
Incineration of Waste	12,900	13,254	12,948	12,921	12,476	12,357	12,357
Coal Mining	4,606	4,169	2,992	2,197	2,455	2,474	2,408
CO ₂ Transport, Injection and Geological Storage	0	0	18	39	65	53	88
Abandoned Oil and Gas Wells	7	7	8	8	8	8	8
<i>Biomass-Wood^a</i>	<i>215,186</i>	<i>206,901</i>	<i>216,652</i>	<i>189,516</i>	<i>191,471</i>	<i>194,318</i>	<i>187,690</i>
<i>International Bunker Fuels^b</i>	<i>103,634</i>	<i>113,328</i>	<i>113,632</i>	<i>69,638</i>	<i>80,180</i>	<i>98,241</i>	<i>96,362</i>
<i>Biofuels-Ethanol^a</i>	<i>4,227</i>	<i>22,943</i>	<i>82,578</i>	<i>71,848</i>	<i>79,064</i>	<i>79,593</i>	<i>80,708</i>
<i>Biofuels-Biodiesel^a</i>	<i>0</i>	<i>856</i>	<i>17,080</i>	<i>17,678</i>	<i>16,112</i>	<i>15,622</i>	<i>18,185</i>
<i>Biomass-MSW^a</i>	<i>18,534</i>	<i>14,722</i>	<i>15,709</i>	<i>15,614</i>	<i>15,329</i>	<i>14,864</i>	<i>14,864</i>
CH₄	14,637	12,826	11,437	10,785	10,353	9,913	9,681
Natural Gas Systems	7,821	7,522	6,748	6,429	6,240	6,135	5,784
Coal Mining	3,860	2,552	1,892	1,648	1,595	1,558	1,621
Petroleum Systems	1,787	1,694	1,807	1,800	1,615	1,295	1,348
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	102	90	92	93	91
Incineration of Waste	+	+	+	+	+	+	+
<i>International Bunker Fuels^b</i>	<i>7</i>	<i>5</i>	<i>4</i>	<i>3</i>	<i>3</i>	<i>3</i>	<i>3</i>
N₂O	228	275	156	139	148	149	136
Stationary Combustion	84	115	84	77	83	85	74
Mobile Combustion	143	158	71	61	64	63	61
Incineration of Waste	2	1	1	1	1	1	1
Petroleum Systems	+	+	+	+	+	+	+
Natural Gas Systems	+	+	+	+	+	+	+
<i>International Bunker Fuels^b</i>	<i>3</i>	<i>3</i>	<i>3</i>	<i>2</i>	<i>2</i>	<i>3</i>	<i>3</i>

2 + Does not exceed 0.5 kt.

3 ^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.

4 ^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.

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

1 Emissions estimates reported in the Energy chapter from fossil fuel combustion and fugitive sources
2 include those from all 50 states, including Hawaii and Alaska, and the District of Columbia. Emissions
3 are also included from U.S. Territories to the extent they are known to occur (e.g., coal mining does not
4 occur in U.S. Territories). For some sources there is a lack of detailed information on U.S. Territories
5 including some non-CO₂ emissions from biomass combustion. As part of continuous improvement
6 efforts, EPA reviews this on an ongoing basis to ensure emission sources are included across all
7 geographic areas including U.S. Territories if they are occurring. See Annex 5 for more information on
8 EPA's assessment of the sources not included in this *Inventory*.

9 Each year, some emission and sink estimates in the *Inventory* are recalculated and revised with
10 improved methods and/or data. In general, recalculations are made to the U.S. greenhouse gas
11 emission estimates either to incorporate new methodologies or, most commonly, to update recent
12 historical data. These improvements are implemented consistently across the previous *Inventory's* time
13 series (i.e., 1990 to 2022) to ensure that the trend is accurate. Key updates in this year's *Inventory*
14 include new data on the activity of battery and plug-in hybrid electric vehicles, the incorporation of
15 MOVES5 output data to replace MOVES3, updated values for natural gas and petroleum consumed by
16 all sectors and U.S. Territories for the years 2020 through 2022, updated electricity statistics which
17 affected commercial sector wood consumption for the years 2014 through 2022, updates for offshore
18 production sources in Gulf of America federal and state waters, and revisions to GHGRP data
19 submissions. The impact of these recalculations averaged a decrease of 0.8 MMT CO₂ Eq. (less than 0.1
20 percent) per year across the time series. For more information on specific methodological updates,
21 please see the Recalculations Discussion section for each category in this chapter.

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

23 EPA's Greenhouse Gas Reporting Program (GHGRP) dataset continues to be an important resource for
24 the *Inventory*, providing not only annual emissions information, but also other annual information, such
25 as activity data and emission factors that can improve and refine national emission estimates and
26 trends over time. GHGRP data also allow EPA to disaggregate national inventory estimates in new ways
27 that can highlight differences across regions and sub-categories of emissions, along with enhancing
28 application of QA/QC procedures and assessment of uncertainties.

29 EPA uses annual GHGRP data in a number of Energy sector categories to improve the national estimates
30 presented in this *Inventory* consistent with IPCC guidelines (see Box 3-2 of this chapter, and Sections
31 3.3 Incineration of Waste, 3.4 Coal Mining, 3.6 Petroleum Systems, 3.7 Natural Gas Systems 3.9 CO₂
32 Transport, Injection and Geological Storage, and 3.11 Biomass and Biofuels Consumption).
33 Methodologies used in EPA's GHGRP are consistent with IPCC guidelines, including higher tier methods.
34 Under EPA's GHGRP, facilities collect detailed information specific to their operations according to
35 detailed measurement standards. It should be noted that the definitions and provisions for reporting
36 fuel types in EPA's GHGRP may differ from those used for national inventory reporting. The *Inventory*
37 report is a comprehensive accounting of all emissions from fuel types identified in the IPCC guidelines
38 and provides a separate reporting of emissions from biomass.

39 In addition to using GHGRP data to estimate emissions (Sections 3.3 Incineration of Waste, 3.4 Coal
40 Mining, 3.6 Petroleum Systems, 3.7 Natural Gas Systems 3.9 CO₂ Transport, Injection and Geological
41 Storage, and 3.11 Biomass and Biofuels Consumption), EPA also uses the GHGRP fuel consumption
42 activity data in the Energy sector to disaggregate industrial end-use sector emissions in the category of
43 CO₂ 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 CO₂, CH₄, and N₂O. Given that CO₂ is the primary gas emitted from fossil fuel combustion and represents the largest share of U.S. total emissions, CO₂ emissions from fossil fuel combustion are discussed at the beginning of this section. An overview of CH₄ and N₂O 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 CO₂ emissions from fossil fuel combustion differ from the estimation of CH₄ and N₂O emissions from stationary combustion and mobile combustion. Thus, three separate descriptions of methodologies, uncertainties, recalculations, and planned improvements are provided at the end of this section. Total CO₂, CH₄, and N₂O emissions from fossil fuel combustion are presented in Table 3-3 and Table 3-4.

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

Gas	1990	2005	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	4,559.1
CH ₄	16.9	14.0	12.6	10.4	10.5	11.3	11.3
N ₂ O	60.1	72.5	40.9	36.6	38.9	39.2	35.8
Total	4,829.2	5,830.6	4,906.2	4,389.3	4,704.0	4,753.3	4,606.2

Note: Totals may not sum due to independent rounding.

Table 3-4: CO₂, CH₄, and N₂O 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	4,559,052
CH ₄	603	500	450	373	375	405	405
N ₂ O	227	274	155	138	147	148	135

CO₂ 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, CO₂ 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 CO₂ 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 (164.2 MMT CO₂ Eq.) from 2022 to 2023. While carbon dioxide emissions from natural gas use increased by 1.0 percent (17.6 MMT CO₂ Eq.) and emissions from petroleum use increased by 0.1 percent (2.9 MMT CO₂ 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, CO₂ emissions from fossil fuel combustion were 4,559.1 MMT CO₂ Eq. (see Table 3-5).⁵

Table 3-5: CO₂ Emissions from Fossil Fuel Combustion by Fuel Type and Sector (MMT CO₂ 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	734.6
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	36.0
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	2.9
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	2,098.3
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	1,704.5
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	17.8
Geothermal^a	0.5	0.5	0.4	0.4	0.4	0.4	0.4
Electric Power	0.5	0.5	0.4	0.4	0.4	0.4	0.4
Total	4,752.2	5,744.1	4,852.6	4,342.3	4,654.6	4,702.8	4,559.1

NO (Not Occurring)

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

1 ^a Although not technically a fossil fuel, geothermal energy-related CO₂ emissions are included for reporting purposes. The source
 2 of CO₂ is non-condensable gases in subterranean heated water.
 3 Note: Totals may not sum due to independent rounding.

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

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

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

22 **Table 3-6: Annual Change in CO₂ Emissions and Total 2023 CO₂ Emissions from Fossil**
 23 **Fuel Combustion for Selected Fuels and Sectors (MMT CO₂ 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%	23.3	1.4%	1,704.5
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%	22.7	1.3%	1,776.2
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%	-7.6	-0.9%	792.1
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%	-143.7	-3.2%	4,559.1

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

25 ^b Includes U.S. Territories.

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

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.

1 As shown in Table 3-6, recent trends in CO₂ emissions from fossil fuel combustion show a 10.5 percent
2 decrease from 2019 to 2020, a 7.2 percent increase from 2020 to 2021, a 1.0 percent increase from
3 2021 to 2022, and a 3.2 percent decrease from 2022 to 2023. These changes contributed to an overall
4 6.1 percent decrease in CO₂ emissions from fossil fuel combustion from 2019 to 2023.

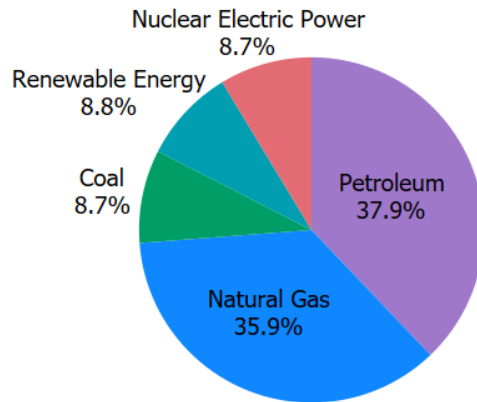
5 Recent trends in CO₂ emissions from fossil fuel combustion are largely driven by the electric power
6 sector, which until 2017 has accounted for the largest portion of these emissions. The types of fuels
7 consumed to produce electricity have changed in recent years. Electric power sector consumption of
8 natural gas primarily increased due to increased production capacity as natural gas-fired plants
9 replaced coal-fired plants and increased electricity demand related to heating and cooling needs (EIA
10 2018; EIA 2024d). Total net electric power generation from all fossil and non-fossil sources decreased by
11 2.9 percent from 2019 to 2020, increased by 2.7 percent from 2020 to 2021, increased by 3.0 percent
12 from 2021 to 2022, and decreased by 1.1 percent from 2022 to 2023 (EIA 2024a). Carbon dioxide
13 emissions from the electric power sector decreased from 2022 to 2023 by 7.7 percent due to increased
14 production and use of natural gas and decreased production and use of coal for electric power
15 generation. Carbon dioxide emissions from coal consumption for electric power generation decreased
16 by 28.7 percent overall since 2019, including an 18.4 percent decrease from 2022 to 2023.

17 Petroleum use in the transportation sector is another major driver of emissions, representing the largest
18 source of CO₂ emissions from fossil fuel combustion in 2023. Emissions from petroleum consumption
19 for transportation have decreased by 3.0 percent since 2019, even as there was a less than 0.05 percent
20 increase in VMT over the same time period. As of 2017, the transportation sector is the largest source of
21 national CO₂ emissions – whereas in prior years, electric power was the largest source sector.

22 In the United States, 82.6 percent of the energy used in 2023 was produced through the combustion of
23 fossil fuels such as petroleum, natural gas, and coal (see Figure 3-4 and Figure 3-5). Specifically,
24 petroleum supplied the largest share of domestic energy demands, accounting for 38 percent of total
25 U.S. energy used in 2023. Natural gas and coal followed in order of fossil fuel energy demand
26 significance, accounting for approximately 36 percent and 9 percent of total U.S. energy used,
27 respectively. Petroleum was consumed primarily in the transportation end-use sector and the majority
28 of coal was used in the electric power sector. Natural gas was broadly consumed in all end-use sectors
29 except transportation (see Figure 3-6) (EIA 2024a). The remaining portion of energy used in 2023 was
30 supplied by nuclear electric power (9 percent) and by a variety of renewable energy sources (9 percent),
31 primarily wind energy, hydroelectric power, solar, geothermal and biomass (EIA 2024a).⁷

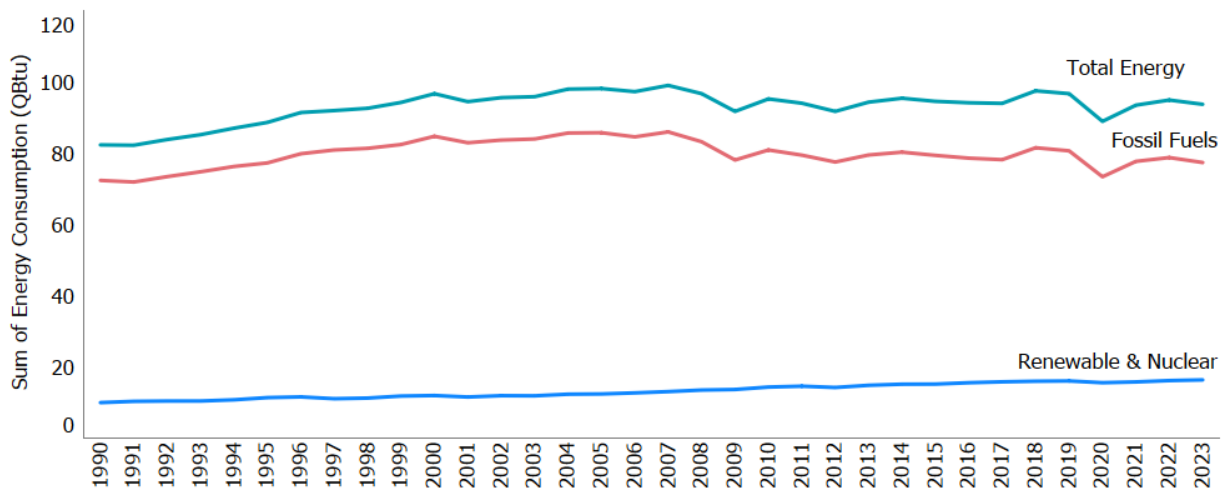
⁷ Renewable energy, as defined in EIA's energy statistics, includes the following energy sources: hydroelectric power, geothermal energy, biomass, solar energy, and wind energy.

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



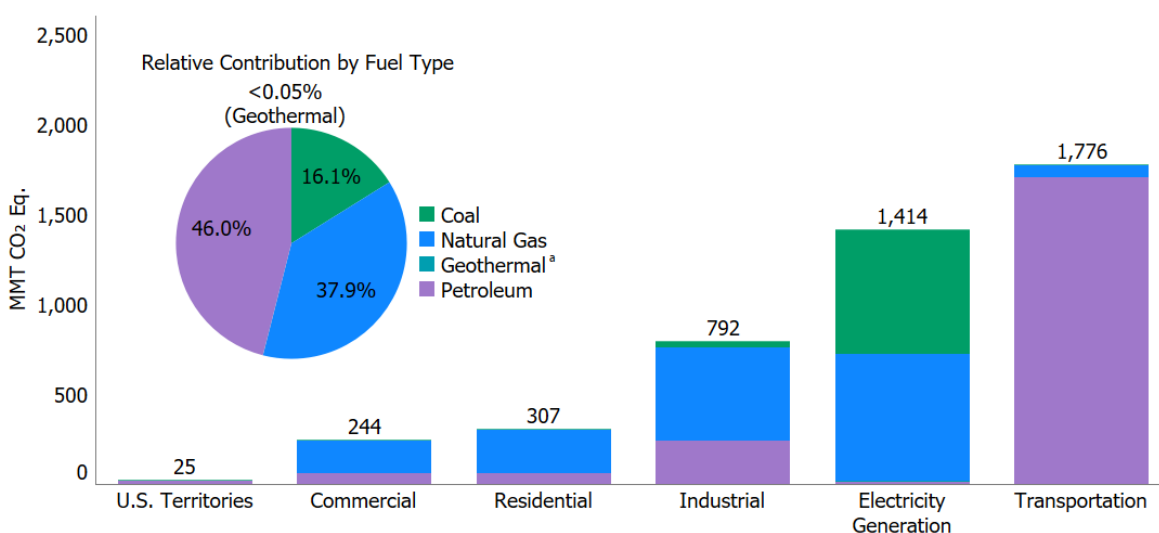
2
3 Note: Totals may not sum due to independent rounding.

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



5

1 **Figure 3-6: 2023 CO₂ Emissions from Fossil Fuel Combustion by Sector and Fuel Type**



2
 3 ^a Although not technically a fossil fuel, geothermal energy-related CO₂ emissions are included for reporting purposes. The source
 4 of CO₂ is non-condensable gases in subterranean heated water.

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

12 The carbon intensity of the electric power sector is impacted by the amount of non-fossil energy sources
 13 of electricity. The utilization (i.e., capacity factors)⁹ of nuclear power plants in 2023 remained high at 92
 14 percent. In 2023, nuclear power represented 19 percent of total electricity generation. Since 1990, the
 15 wind and solar power sectors have shown strong growth and have become relatively important sources
 16 of electricity. Between 1990 and 2023, renewable energy generation (in kWh) from solar and wind energy
 17 have increased from 0.1 percent in 1990 to 15 percent of total electricity generation in 2023, which
 18 helped drive the decrease in the carbon intensity of the electricity supply in the United States.

19 Stationary Combustion

20 The direct combustion of fuels by stationary sources in the electric power, industrial, commercial, and
 21 residential sectors represent the greatest share of U.S. greenhouse gas emissions. Table 3-7 presents
 22 CO₂ emissions from fossil fuel combustion by stationary sources. The CO₂ emitted is closely linked to
 23 the type of fuel being combusted in each sector (see the Methodology section of CO₂ from Fossil Fuel
 24 Combustion). In addition to CO₂ emissions, CH₄ and N₂O are emitted from fossil fuel combustion as

⁸ See the sections entitled Stationary Combustion and Mobile Combustion in this chapter for information on non-CO₂ 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).

1 well. Table 3-8 and Table 3-9 present CH₄ and N₂O emissions from the combustion of fuels in stationary
 2 sources. The CH₄ and N₂O emissions are linked to the type of fuel being combusted as well as the
 3 combustion technology (see the Methodology section for CH₄ and N₂O from Stationary Combustion).

4 **Table 3-7: CO₂ Emissions from Stationary Fossil Fuel Combustion (MMT CO₂ 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	792.1
Coal	157.8	117.8	49.4	43.0	43.0	43.0	36.0
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	25.3
Coal	0.5	3.0	3.6	3.1	2.9	2.9	2.9
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	17.8
Total	3,283.3	3,885.6	3,036.0	2,769.4	2,901.1	2,949.2	2,782.8

5 NO (Not Occurring)

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

7 **Table 3-8: CH₄ Emissions from Stationary Combustion (MMT CO₂ 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

- 1 + Does not exceed 0.05 MMT CO₂ Eq.
- 2 NO (Not Occurring)
- 3 NE (Not Estimated)
- 4 Note: Totals may not sum due to independent rounding.

5 **Table 3-9: N₂O Emissions from Stationary Combustion (MMT CO₂ 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	0.1
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

- 1 + Does not exceed 0.05 MMT CO₂ Eq.
2 NO (Not Occurring)
3 NE (Not Estimated)
4 Note: Totals may not sum due to independent rounding.

5 Fossil Fuel Combustion Emissions by Sector

6 Table 3-10 provides an overview of the CO₂, CH₄, and N₂O emissions from fossil fuel combustion by
7 sector, including transportation, electric power, industrial, residential, commercial, and U.S. Territories.

8 **Table 3-10: CO₂, CH₄, and N₂O Emissions from Fossil Fuel Combustion by Sector (MMT**
9 **CO₂ Eq.)**

End-Use Sector	1990	2005	2019	2020	2021	2022	2023
Transportation	1,513.9	1,905.8	1,838.3	1,591.5	1,773.0	1,772.8	1,795.1
CO ₂	1,468.9	1,858.6	1,816.6	1,573.0	1,753.5	1,753.6	1,776.2
CH ₄	7.2	5.2	2.8	2.5	2.6	2.6	2.6
N ₂ O	37.8	42.0	18.8	16.1	16.8	16.6	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 ₂ O	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	795.5
CO ₂	876.5	847.6	809.8	763.4	780.5	799.7	792.1
CH ₄	2.1	1.9	1.7	1.6	1.6	1.6	1.5
N ₂ O	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 ₂ O	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 ₂ O	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	25.4
Total	4,829.2	5,830.6	4,906.2	4,389.3	4,704.0	4,753.3	4,606.2

- 10 ^a U.S. Territories are not apportioned by sector, and emissions shown in the table are total greenhouse gas emissions from all fuel
11 combustion sources.
12 Note: Totals may not sum due to independent rounding.

1 Other than the greenhouse gases CO₂, CH₄, and N₂O, gases emitted from stationary combustion include
 2 the greenhouse gas precursors nitrogen oxides (NO_x), CO, NMVOCs, and sulfur dioxide (SO₂). Methane
 3 and N₂O emissions from stationary combustion sources depend upon fuel characteristics and the size
 4 and vintage of combustion device, along with combustion technology, pollution control equipment,
 5 ambient environmental conditions, and operation and maintenance practices. Nitrous oxide emissions
 6 from stationary combustion are closely related to air-fuel mixes and combustion temperatures, as well
 7 as the characteristics of any pollution control equipment that is employed. Methane emissions from
 8 stationary combustion are primarily a function of the CH₄ content of the fuel and combustion efficiency.

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

20 An alternative method of presenting combustion emissions is to allocate emissions associated with
 21 electric power to the sectors in which it is used. Four end-use sectors are defined: transportation,
 22 industrial, residential, and commercial. In Table 3-11 below, electric power emissions have been
 23 distributed to each end-use sector based upon the sector's share of national electricity use, with the
 24 exception of CH₄ and N₂O from transportation electricity use.¹⁰ Emissions from U.S. Territories are also
 25 calculated separately due to a lack of end-use-specific consumption data.¹¹ This method assumes that
 26 emissions from combustion sources are distributed across the four end-use sectors based on the ratio
 27 of electricity use in that sector. The results of this alternative method are presented in Table 3-11.

28 **Table 3-11: CO₂, CH₄, and N₂O Emissions from Fossil Fuel Combustion by End-Use**
 29 **Sector with Electricity Emissions Distributed (MMT CO₂ Eq.)**

End-Use Sector	1990	2005	2019	2020	2021	2022	2023
Transportation	1,517.0	1,910.5	1,842.5	1,595.0	1,776.9	1,777.2	1,800.1
CO ₂	1,472.0	1,863.3	1,820.9	1,576.4	1,757.5	1,758.0	1,781.3
CH ₄	7.2	5.2	2.8	2.5	2.6	2.6	2.6
N ₂ O	37.8	42.0	18.8	16.1	16.8	16.6	16.2
Industrial	1,574.8	1,597.0	1,285.1	1,182.3	1,235.3	1,246.5	1,205.2
CO ₂	1,562.9	1,584.0	1,275.3	1,173.3	1,225.7	1,236.9	1,196.6
CH ₄	2.2	2.2	2.1	2.0	2.0	2.0	1.9
N ₂ O	9.7	10.8	7.6	7.1	7.6	7.6	6.7

¹⁰ Separate calculations are performed for transportation-related CH₄ and N₂O. 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	860.6	891.1	901.6	815.6
CH ₄	6.0	4.9	5.8	4.2	4.2	4.9	5.0
N ₂ O	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 ₂ O	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	25.4
Total	4,829.2	5,830.6	4,906.2	4,389.3	4,704.0	4,753.3	4,606.2

^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 CO₂ emissions in the United States, representing 28.8 percent of total CO₂ emissions from all CO₂ emissions sources across the United States and 31.0 percent of CO₂ emissions from fossil fuel combustion in 2023. Methane and N₂O 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 N₂O from electric power represented 12.7 and 46.5 percent of total CH₄ and N₂O 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 22.7 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 CO₂ 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.

1 Coal-fired electric generation (in kilowatt-hours [kWh]) decreased from 54 percent of generation in 1990
 2 to 17 percent in 2023.¹³ This corresponded with an increase in natural gas generation and renewable
 3 energy generation, largely from wind and solar energy. Natural gas generation (in kWh) represented 11
 4 percent of electric power generation in 1990 and increased over the 34-year period to represent 42
 5 percent of electric power sector generation in 2023 (see Table 3-12). Natural gas has a much lower
 6 carbon content than coal and is generated in power plants that are generally more efficient in terms of
 7 kWh produced per Btu of fuel combusted, which has led to lower emissions as natural gas replaces
 8 coal-powered electricity generation. Natural gas and coal used in the United States in 2023 had an
 9 average carbon content of 14.43 MMT C/Qbtu and 26.15 MMT C/Qbtu respectively.

10 **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%
<i>Net Electricity Generation (Billion kWh)^b</i>	2,905	3,902	3,966	3,851	3,955	4,076	4,031

11 + Does not exceed 0.05 percent.

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

13 ^b Represents net electricity generation from the electric power sector. Excludes net electricity generation from commercial and
 14 industrial combined-heat-and-power and electricity-only plants. Does not include electricity generation from purchased steam
 15 as the fuel used to generate the steam cannot be determined.

16 In 2023, CO₂ emissions from the electric power sector decreased by 7.7 percent relative to 2022. This
 17 decrease in CO₂ emissions was primarily driven by a decrease in coal consumed to produce electricity
 18 in the electric power sector. Consumption of coal for electric power decreased by 18.4 percent while
 19 consumption of natural gas increased 6.9 percent from 2022 to 2023, leading to an overall decrease in
 20 emissions. There has also been a rapid increase in renewable electricity generation in the electric power
 21 sector in recent years and electricity generation from renewable sources remained relatively flat from
 22 2022 to 2023 (see Table 3-12). A decrease in coal-fired electricity generation and increases in natural gas
 23 and renewable energy sources for electricity generation contributed to a decoupling of emissions trends
 24 from electric power generation trends starting around 2005 (EIA 2024h) (see Figure 3-7).

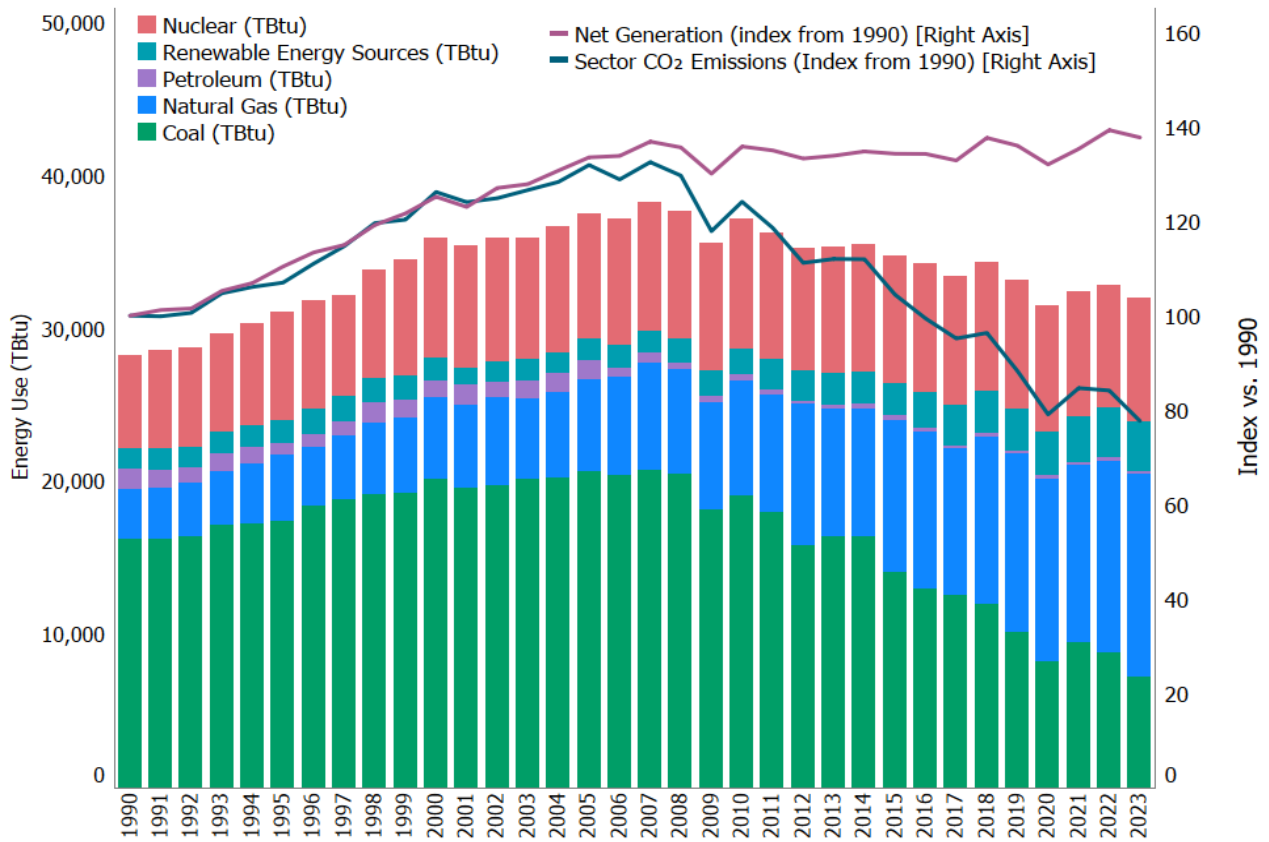
25 The shift from coal to natural gas comes from a variety of factors including the increase in natural gas
 26 generation, particularly between 2005 and 2020 and the relative prices of using coal vs. natural gas for
 27 electricity generation (EIA 2022a; EIA 2022b). The aging coal fleet and coal plant retirements also
 28 contributes to why this trend is continuing (EIA 2025). From 2022 to 2023, coal consumption decreased
 29 18 percent while natural gas consumption increased 7 percent.

30 Also, in 2023 the Petra Nova project sequestered 359,840 metric tons of CO₂ from a coal fired power
 31 plant. These emissions have been netted out of the results shown in this chapter for electric power
 32 sector coal CO₂ emissions. More information on CO₂ transport, injection, and geological storage can be
 33 found in Section 3.9.

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

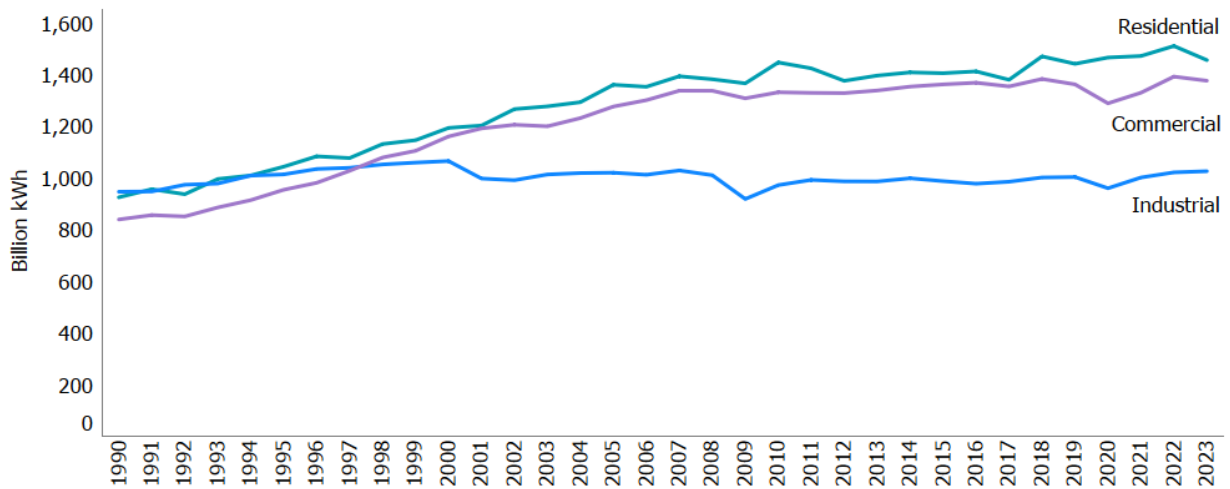
1 Renewable energy generation (in kWh) from wind and solar energy increased from 0.1 percent of total
 2 generation in 1990 to 5 percent in 2015 and increased at a faster pace to 15 percent of total generation
 3 in 2023. The decrease in carbon intensity occurred even as total electricity retail sales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

5 **Figure 3-7: Fuels Used in Electric Power Generation and Total Electric Power Sector**
 6 **CO₂ Emissions**



7
 8 Electricity was used primarily in the residential, commercial, and industrial end-use sectors for lighting,
 9 heating, electric motors, appliances, electronics, and air conditioning (see Figure 3-8). Note that
 10 transportation is an end-use sector as well but is not shown in Figure 3-8 due to the sector's relatively
 11 low percentage of electricity use. The Transportation Sector and Mobile Combustion section provides a
 12 break-out of CO₂ emissions from electricity use in the transportation end-use sector.

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



2
3 In 2023, electricity sales to the residential and commercial end-use sectors, as presented in Figure 3-8,
4 decreased by 3.9 percent and increased 1.2 percent relative to 2022, respectively. Electricity sales to
5 the industrial sector in 2023 decreased by approximately 1.1 percent relative to 2022. The sections
6 below describe end-use sector energy use in more detail. Overall, in 2023, the amount of electricity
7 retail sales (in kWh) decreased by 1.3 percent relative to 2022.

8 **Industrial Sector**

9 Industrial sector CO₂, CH₄, and N₂O emissions accounted for 17, 13, and 5 percent of CO₂, CH₄, and
10 N₂O emissions from fossil fuel combustion, respectively, in 2023. Carbon dioxide, CH₄, and N₂O
11 emissions resulted from the direct consumption of fossil fuels for steam and process heat production.

12 The industrial end-use sector, per the underlying energy use data from EIA, includes activities such as
13 manufacturing, construction, mining, and agriculture. The largest of these activities in terms of energy
14 use is manufacturing, of which six industries—petroleum refineries, chemicals, paper, primary metals,
15 food, and nonmetallic mineral products—represent the majority of the energy use (EIA 2024a; EIA
16 2009b).

17 There are many dynamics that impact emissions from the industrial sector including economic activity,
18 changes in the make-up of the industrial sector, changes in the emissions intensity of industrial
19 processes, and weather-related impacts on heating and cooling of industrial buildings.¹⁴ Structural
20 changes within the U.S. economy that lead to shifts in industrial output away from energy-intensive
21 manufacturing products to less energy-intensive products (e.g., from steel to computer equipment)
22 have had a significant effect on industrial emissions.

23 From 2022 to 2023, total industrial production and manufacturing output increased by 0.2 percent (FRB
24 2023). Over this period, output increased slightly across production indices for Food, Nonmetallic
25 Mineral Products, and Paper. Production of chemicals, petroleum refineries, and primary metals
26 declined slightly between 2022 and 2023 (see Figure 3-9). From 2022 to 2023, total energy use in the

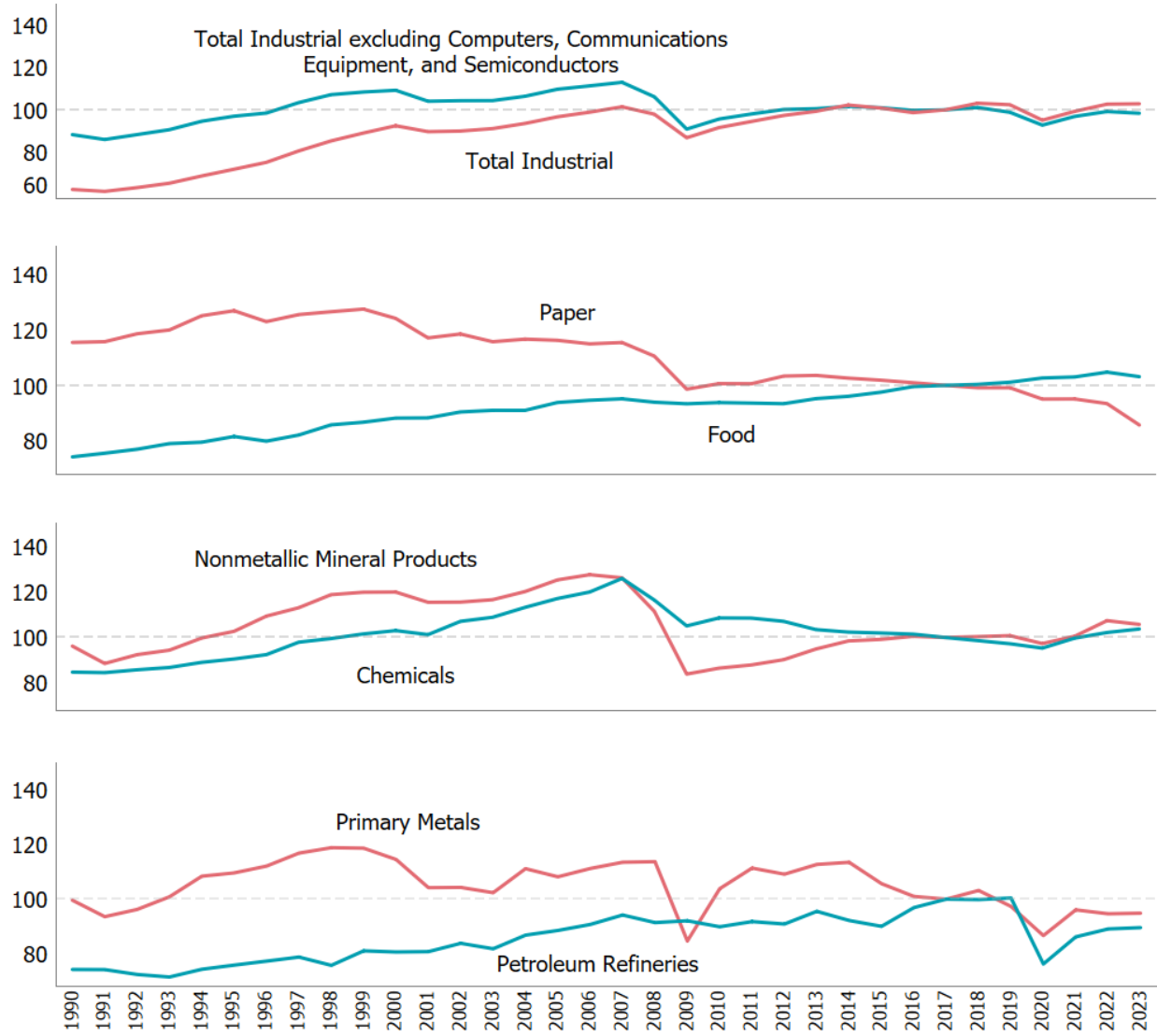
¹⁴ Some commercial customers are large enough to obtain an industrial price for natural gas and/or electricity and are consequently grouped with the industrial end-use sector in U.S. energy statistics. These misclassifications of large commercial customers likely cause the industrial end-use sector to appear to be more sensitive to weather conditions.

1 industrial sector decreased by 0.9 percent, driven mainly by a 16.5 percent decrease in coal
2 consumption in the industrial sector. Consumption of renewables decreased 3.0 percent from 2022 to
3 2023. Due to the relative increases and decreases of individual indices there was an increase in natural
4 gas and a decrease in electricity used by this sector (see Figure 3-10). In 2023, CO₂, CH₄, and N₂O
5 emissions from fossil fuel combustion and electricity use within the industrial end-use sector totaled
6 1,205.2 MMT CO₂ Eq., a 3.3 percent decrease from 2022 emissions.

7 Through EPA's Greenhouse Gas Reporting Program (GHGRP), specific industrial sector trends can be
8 discerned from the overall total EIA industrial fuel consumption data used for these calculations. For
9 example, from 2022 to 2023, the underlying EIA data showed increased consumption of natural gas,
10 decreased consumption of petroleum, and decreased consumption of coal in the industrial sector. The
11 GHGRP data highlights that several industries contributed to these trends, including chemical
12 manufacturing; pulp, paper and print; food processing, beverages and tobacco; minerals
13 manufacturing; and agriculture-forest-fisheries.¹⁵

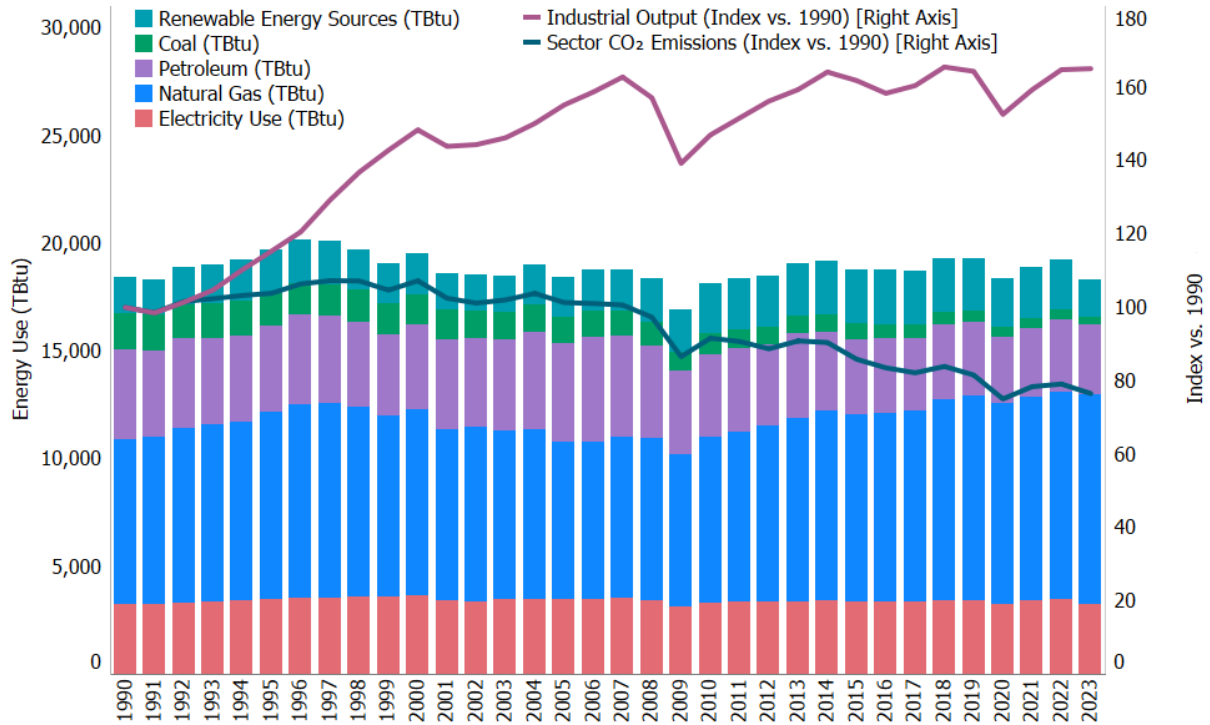
¹⁵ Further details on industrial sector combustion emissions are provided by EPA's GHGRP. See <http://ghgdata.epa.gov/ghgp/main.do>.

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



2

1 **Figure 3-10: Fuels and Electricity Used in Industrial Sector, Industrial Output, and**
 2 **Total Sector CO₂ Emissions (Including Electricity)**



3
 4 Despite the growth in industrial output (65 percent) and the overall U.S. economy (125 percent) from
 5 1990 to 2023, direct CO₂ emissions from fossil fuel combustion in the industrial sector decreased by 9.6
 6 percent over the same time series. A number of factors are assumed to result in decoupling of growth in
 7 industrial output from industrial greenhouse gas emissions, for example: (1) more rapid growth in output
 8 from less energy-intensive industries relative to traditional manufacturing industries, and (2) energy-
 9 intensive industries such as steel are employing new methods, such as electric arc furnaces, that are
 10 less carbon-intensive than the older methods.

11 **Box 3-2: Uses of Greenhouse Gas Reporting Program Data and Improvements in**
 12 **Reporting Emissions from Industrial Sector Fossil Fuel Combustion**

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

18 For GHGRP 2010 through 2023 reporting years, facility-level fossil fuel combustion emissions reported
 19 through EPA's GHGRP were categorized and distributed to specific industry types by utilizing facility-
 20 reported NAICS codes (as published by the U.S. Census Bureau). As noted previously in this report, the
 21 definitions and provisions for reporting fuel types in EPA's GHGRP include some differences from the
 22 *Inventory's* use of EIA national fuel statistics for national inventory reporting. The IPCC has provided

1 guidance on aligning facility-level reported fuels and fuel types published in national energy statistics,
2 which guided this exercise.¹⁶

3 As with previous *Inventory* reports, the current effort represents an attempt to align, reconcile, and
4 coordinate the facility-level reporting of fossil fuel combustion emissions under EPA's GHGRP with the
5 national-level approach presented in this report. Progress was made on certain fuel types for specific
6 industries and has been included in common data tables.¹⁷ The efforts in reconciling fuels focus on
7 standard, common fuel types (e.g., natural gas, distillate fuel oil) where the fuels in EIA's national
8 statistics aligned well with facility-level GHGRP data. For these reasons, the current information should
9 be viewed as an initial attempt at this exercise. Additional efforts will be made for future *Inventory*
10 reports to improve the mapping of fuel types and examine ways to reconcile and coordinate any
11 differences between facility-level data and national statistics. The current analysis includes the full time
12 series. Analyses were conducted linking GHGRP facility-level reporting with the information published
13 by EIA in its MECS data in order to disaggregate the full 1990 through 2023 time period. It is believed that
14 the current analysis has led to improvements in the presentation of data in the *Inventory*, but further
15 work will be conducted, and future improvements will be realized in subsequent *Inventory* reports. This
16 includes incorporating the latest MECS data as it becomes available.
17

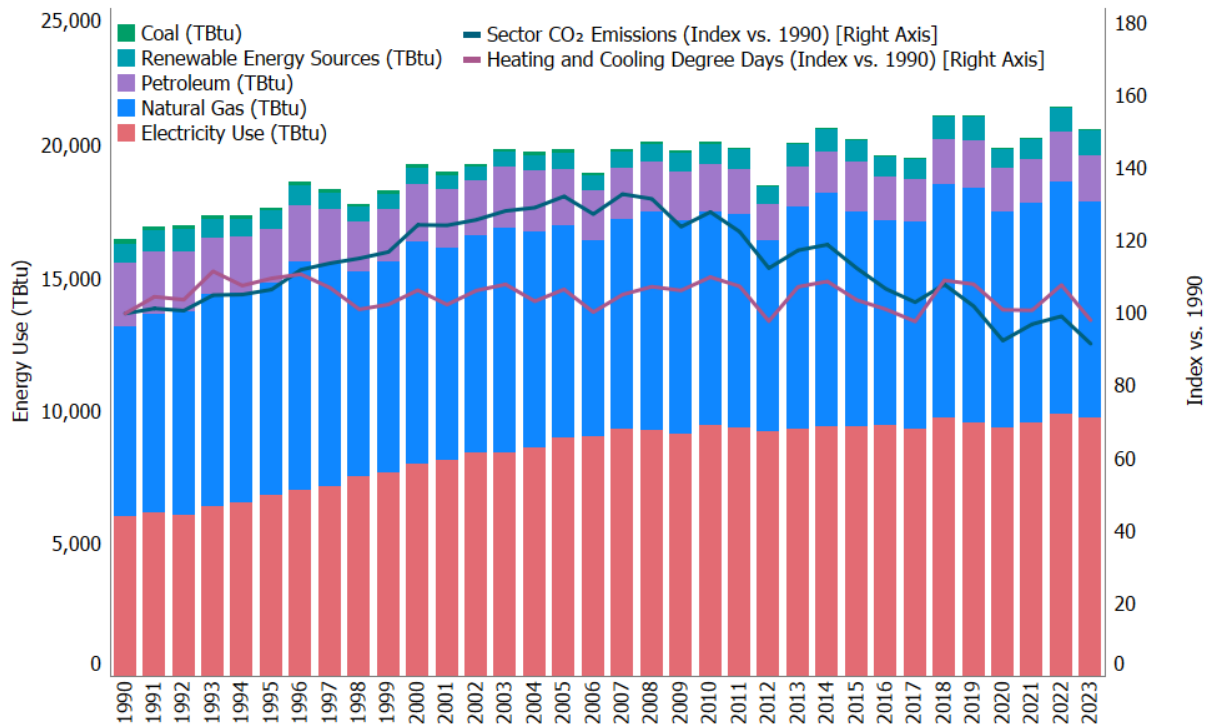
18 Residential and Commercial Sectors

19 Total direct and indirect emissions from the residential and commercial sectors have generally
20 decreased since 2005. This is due in part to reduced electricity sector emissions intensity which results
21 in decreased indirect emissions from electricity use. For example, starting around 2014, total energy use
22 and emissions begin to decouple due to decarbonization of the electric power sector (see Figure 3-11).
23 Short-term trends in the residential and commercial sectors are often correlated with seasonal
24 fluctuations in energy use caused by weather conditions, rather than prevailing economic conditions.
25 Population growth and a trend towards larger houses has led to increasing energy use over the time
26 series, while population migration to warmer areas and improved energy efficiency and building
27 insulation have countered the increase in energy use in recent years. The shift toward energy-efficient
28 products and more stringent energy efficiency standards for household equipment has contributed to a
29 decrease in energy demand in households (EIA 2023b; Nadel, et al. 2015), resulting in a decrease in
30 energy-related emissions in the residential sector since 1990.

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>.

1 **Figure 3-11: Fuels and Electricity Used in Residential and Commercial Sectors,**
 2 **Heating and Cooling Degree Days, and Total Sector CO₂ Emissions (Including**
 3 **Electricity)**

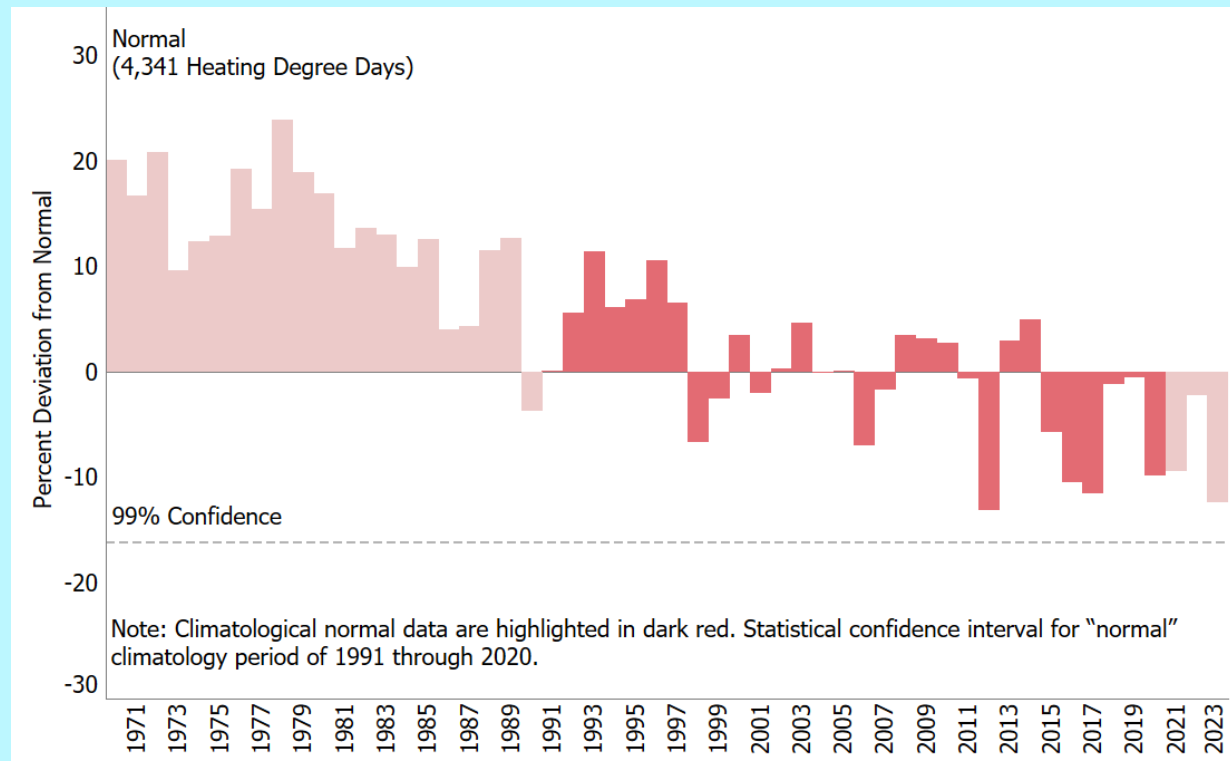


4
 5 In 2023, excluding indirect emissions from electricity use, the residential and commercial sectors
 6 accounted for 7 and 5 percent of CO₂ emissions from fossil fuel combustion, respectively; 38 and 11
 7 percent of CH₄ emissions from fossil fuel combustion, respectively; and 2 and 1 percent of N₂O
 8 emissions from fossil fuel combustion, respectively. Emissions from these sectors are primarily
 9 attributable to building-related activities such as the direct consumption of natural gas and petroleum
 10 products, primarily for heating and cooking needs. Coal consumption was a minor component of energy
 11 use in the commercial sector and did not contribute to any energy use in the residential sector.
 12 Greenhouse gas emissions from commercial and residential buildings also increase substantially when
 13 emissions from electricity end-use are included, because the building sector uses 75 percent of the
 14 electricity generated in the United States (e.g., for heating, ventilation, and air conditioning; lighting; and
 15 appliances) (NREL 2023). In 2023, total emissions (CO₂, CH₄, and N₂O) from fossil fuel combustion and
 16 electricity use within the residential and commercial end-use sectors were 827.3 MMT CO₂ Eq. and
 17 748.2 MMT CO₂ Eq., respectively. Direct CO₂, CH₄, and N₂O emissions from fossil fuel combustion
 18 within the residential and commercial end-use sectors decreased by 8.2 and 5.8 percent from 2022 to
 19 2023, respectively. This is mainly due to a decrease in heating degree days (10.4 percent) and cooling
 20 degree days (5.2 percent) from 2022 to 2023 which decreased energy demand for heating and cooling in
 21 the residential and commercial sectors. From 2022 to 2023 there was an 8.5 and a 5.6 percent increase
 22 in direct energy use in the residential and commercial sectors respectively.
 23 In 2023, combustion emissions from natural gas consumption represented 81 and 75 percent of the
 24 direct fossil fuel CO₂ emissions from the residential and commercial sectors, respectively. Carbon
 25 dioxide emissions from natural gas combustion in the residential and commercial sectors in 2023
 26 decreased by 9.0 percent and 5.0 percent from 2022, respectively.

Box 3-3: Weather and Non-Fossil Energy Effects on CO₂ 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 12.3 percent below normal¹⁸ (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 2024a).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.

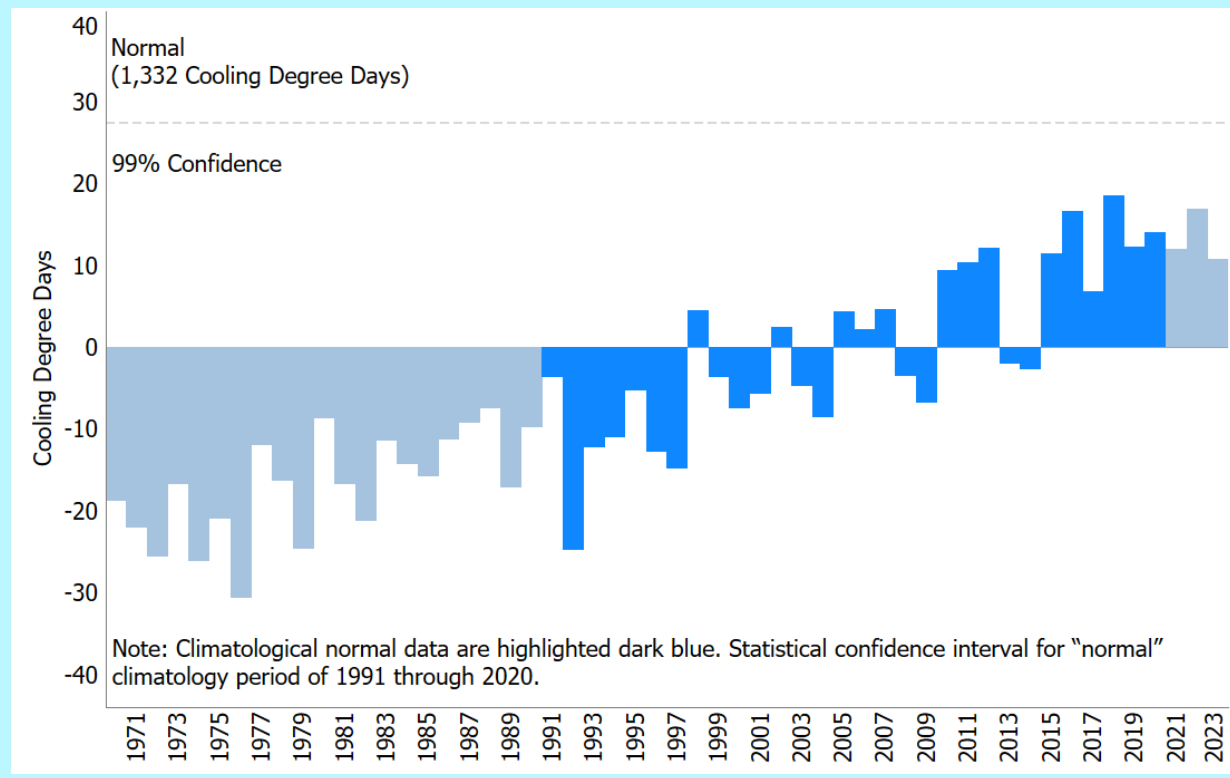
Figure 3-12: Annual Deviations from Normal Heating Degree Days for the United States (1970–2023, Index Normal = 100)



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.

1 **Figure 3-13: Annual Deviations from Normal Cooling Degree Days for the United States**
 2 **(1970–2023, Index Normal = 100)**



3
4
5

6 **U.S. Territories**

7 Emissions from U.S. Territories are based on the fuel consumption in American Samoa, Guam, Puerto
 8 Rico, U.S. Virgin Islands, Wake Island, and other outlying U.S. Pacific Islands. As described in the
 9 Methodology section of CO₂ from Fossil Fuel Combustion, this data is collected separately from the
 10 sectoral-level data available for the general calculations. As sectoral information is not available for U.S.
 11 Territories, CO₂, CH₄, and N₂O emissions are not presented for U.S. Territories in the tables above by
 12 sector, though the emissions will occur across all sectors and sources including stationary,
 13 transportation and mobile combustion sources.

14 **Transportation Sector and Mobile Combustion**

15 This discussion of transportation emissions follows the alternative method of presenting combustion
 16 emissions by allocating emissions associated with electricity generation to the transportation end-use
 17 sector, as presented in Table 1-9. Table 1-8 presents direct CO₂, CH₄, and N₂O emissions from all
 18 transportation sources (i.e., excluding emissions allocated to electricity consumption in the
 19 transportation end-use sector).

20 The transportation end-use sector and other mobile combustion accounted for 1,800.1 MMT CO₂ Eq. in
 21 2023, which represented 39 percent of CO₂ emissions from fossil fuel combustion, 23 percent of CH₄

1 emissions from fossil fuel combustion, and 46 percent of N₂O emissions from fossil fuel combustion.²⁰
2 Fuel purchased in the U.S. for international aircraft and marine travel accounted for an additional 97.2
3 MMT CO₂ Eq. in 2023; these emissions are recorded as international bunkers and are not included in
4 U.S. totals in line with IPCC guidelines.

5 ***Transportation End-Use Sector***

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

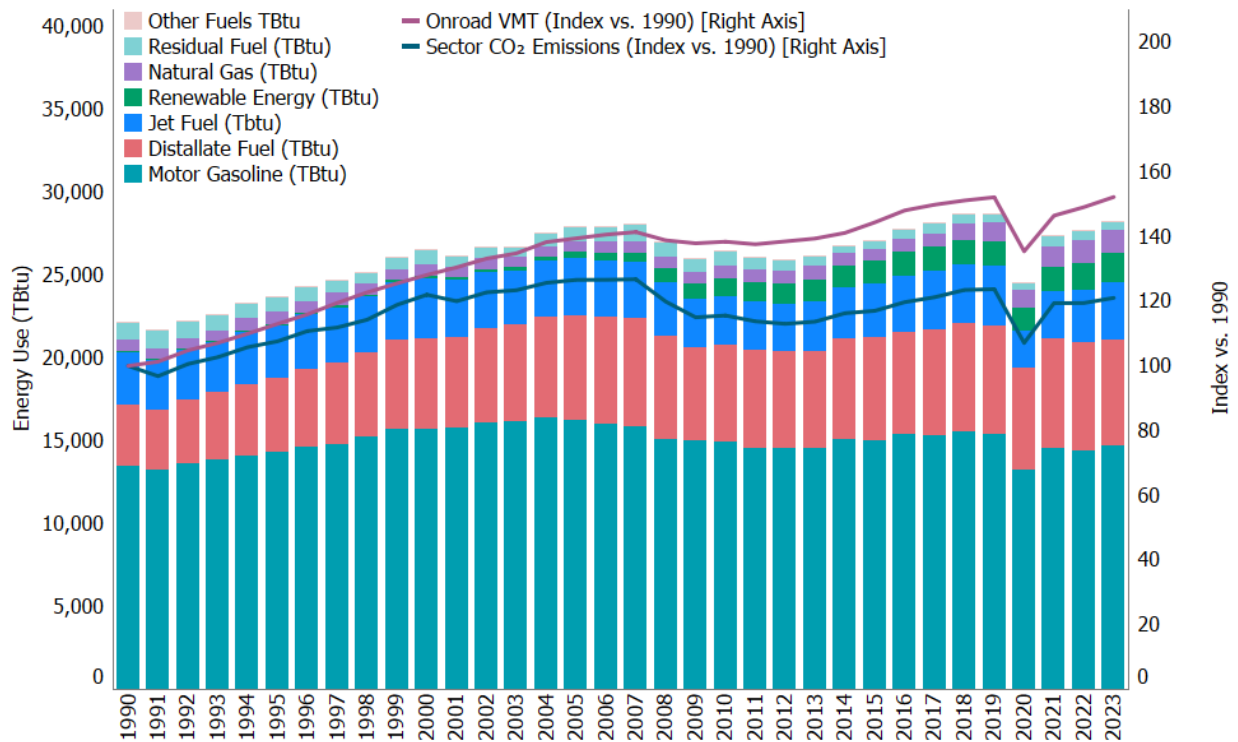
16 Commercial aircraft emissions decreased by 5 percent between 2019 and 2023 and have decreased 7
17 percent since 2007 (FAA 2022 and DOT 1991 through 2023).²¹ Decreases in jet fuel emissions (excluding
18 bunkers) started in 2007, due in part to improved operational efficiency that results in more direct flight
19 routing, improvements in aircraft and engine technologies to reduce fuel burn and emissions, and the
20 accelerated retirement of older, less fuel-efficient aircraft; however, the sharp decline in commercial
21 aircraft emissions from 2019 to 2020 and their gradual recovery since is primarily due to COVID-19
22 impacts on scheduled passenger air travel.

23 Almost all of the energy consumed for transportation was supplied by petroleum-based products, with
24 more than half being related to gasoline consumption in automobiles and other highway vehicles. Other
25 fuel uses, especially diesel fuel for freight trucks and jet fuel for aircraft, accounted for the remainder.
26 The primary driver of transportation-related emissions was CO₂ from fossil fuel combustion, which
27 increased by 21 percent from 1990 to 2023. Annex 3.2 presents the total emissions from all
28 transportation and mobile sources, including CO₂, N₂O, CH₄, and HFCs.

²⁰ Note that these totals include CO₂, CH₄ and N₂O emissions from some sources in the U.S. Territories (ships and boats, recreational boats, non-transportation mobile sources) and CH₄ and N₂O emissions from transportation rail electricity.

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

1 **Figure 3-14: Fuels Used in Transportation Sector, On-road VMT, and Total Sector CO₂**
 2 **Emissions**



3
 4 Notes: Distillate fuel, residual fuel, and jet fuel include adjustments for international bunker fuels. Distillate fuel and motor
 5 gasoline include adjustments for the sectoral allocation of these fuels. Other Fuels includes aviation gasoline and propane.
 6 Source: Information on fuel consumption was obtained from EIA (2024).

7 **Transportation Fossil Fuel Combustion CO₂ Emissions**

8 Domestic transportation CO₂ emissions increased by 21 percent (309.3 MMT CO₂ Eq.) between 1990
 9 and 2023, an annualized increase of 0.6 percent. This includes a 24 percent increase in CO₂ emissions
 10 between 1990 and 2019, followed by a 13 percent decrease from 2019 to 2020. Carbon dioxide
 11 emissions then increased by 13 percent between 2020 and 2023. Among domestic transportation
 12 sources, light-duty vehicles (including passenger cars and light-duty trucks) represented 57 percent of
 13 CO₂ emissions, medium- and heavy-duty trucks and buses 25 percent, commercial aircraft 7 percent,
 14 and other sources 11 percent. See Table 3-13 for a detailed breakdown of transportation CO₂ emissions
 15 by mode and fuel type.

16 Almost all of the energy consumed by the transportation sector is petroleum-based, including motor
 17 gasoline, diesel fuel, jet fuel, and residual oil. Carbon dioxide emissions from the combustion of ethanol
 18 and biodiesel for transportation purposes, along with the emissions associated with the agricultural and
 19 industrial processes involved in the production of biofuel, are captured in other *Inventory* sectors.²²
 20 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>.

1 13.2 billion gallons in 2023, while biodiesel consumption has increased from 0.01 billion gallons in 2001
2 to 1.6 billion gallons in 2023. For additional information, see Section 3.11 on biofuel consumption at the
3 end of this chapter and Table A-75 in Annex 3.2.

4 Carbon dioxide emissions from passenger cars and light-duty trucks totaled 1,007.9 MMT CO₂ in 2023,
5 an increase of 10 percent (95.2 MMT CO₂) from 1990. The increase in CO₂ emissions from passenger
6 cars and light-duty trucks from 1990 to 2023 was due, in large part, to increased demand for travel as
7 fleet-wide light-duty vehicle fuel economy was relatively stable (average new vehicle fuel economy
8 declined slowly from 1990 through 2004 and then increased more rapidly from 2005 through 2023).
9 Carbon dioxide emissions from passenger cars and light-duty trucks peaked at 1,145.5 MMT in 2004,
10 and since then have declined about 11 percent. The decline in new light-duty vehicle fuel economy
11 between 1990 and 2004 (see Figure 3-15) reflects the increasing market share of light-duty trucks, which
12 grew from about 30 percent of new vehicle sales in 1990 to 48 percent in 2004. Starting in 2005, average
13 new vehicle fuel economy began to increase while light-duty vehicle VMT grew only modestly for much
14 of the period. Light-duty vehicle VMT grew by less than one percent or declined each year between 2005
15 and 2013, and again between 2017 and 2019. VMT grew at faster rates of 2.3 percent from 2014 to 2015,
16 and 1.7 percent from 2015 to 2016. From 2019 to 2020, light-duty vehicle VMT declined by 12.0 percent
17 due to COVID-19 pandemic; from 2020 to 2023 light-duty vehicle VMT rebounded as a part of the
18 ongoing recovery from the pandemic, increasing by 12.2 percent.

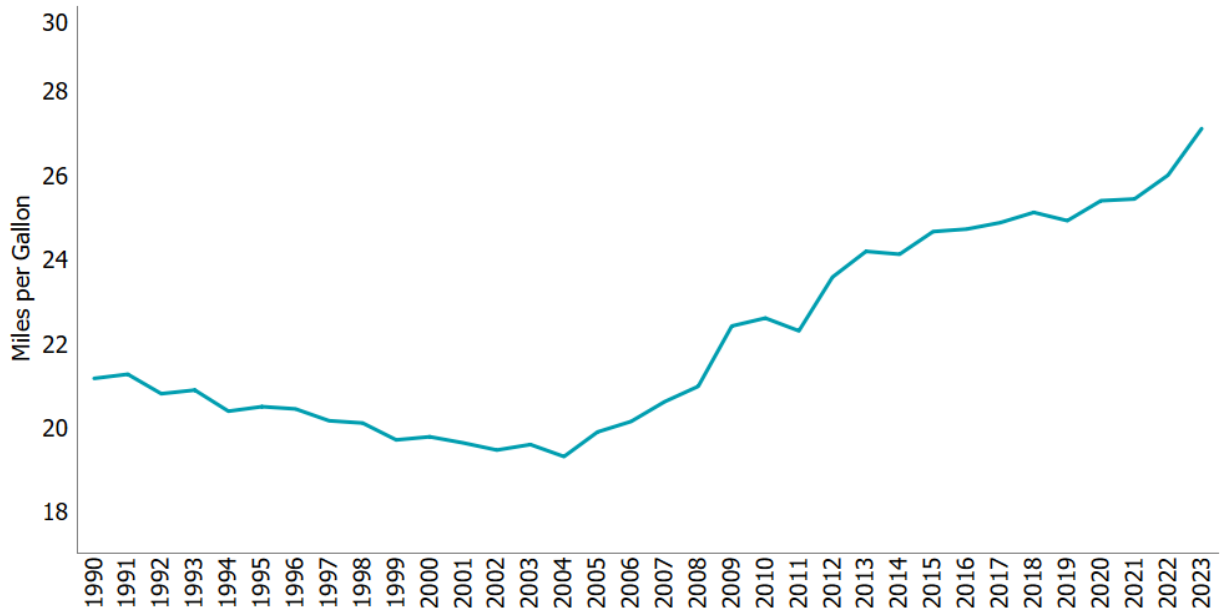
19 Average new vehicle fuel economy has improved almost every year since 2005 while the light-duty truck
20 share of new vehicle sales decreased to about 33 percent of new vehicles in 2009 and has since varied
21 from year to year between 36 and 63 percent. Since 2014, the light-duty truck share has steadily
22 increased, reaching 62 percent of new vehicle sales in model year 2023. See Annex 3.2 for data by
23 vehicle mode and information on VMT and the share of new vehicles (in VMT).

24 Medium- and heavy-duty truck CO₂ emissions increased by 78 percent from 1990 to 2023. This increase
25 was largely due to a substantial growth in medium- and heavy-duty truck VMT, which increased by 84
26 percent between 1990 and 2023.

27 Carbon dioxide from the domestic operation of commercial aircraft increased by 18 percent (19.8 MMT
28 CO₂) from 1990 to 2023. Across all categories of aviation, excluding international bunkers, CO₂
29 emissions decreased by 4 percent (6.9 MMT CO₂) between 1990 and 2023.²³ Carbon dioxide emissions
30 from military aircraft decreased 66 percent between 1990 and 2023. Commercial aircraft CO₂ emissions
31 increased 27 percent between 1990 and 2007, dropped 2 percent from 2007 to 2019, dropped another
32 33 percent from 2019 to 2020, then increased by 30 percent from 2020 to 2023. Overall, this represents
33 a change of approximately 18 percent between 1990 and 2023. Transportation sources also produce
34 CH₄ and N₂O; these emissions are included in Figure 3-14 and Table 3-15 and in the CH₄ and N₂O from
35 Mobile Combustion section. Annex 3.2 presents total emissions from all transportation and mobile
36 sources, including CO₂, CH₄, N₂O, and HFCs.

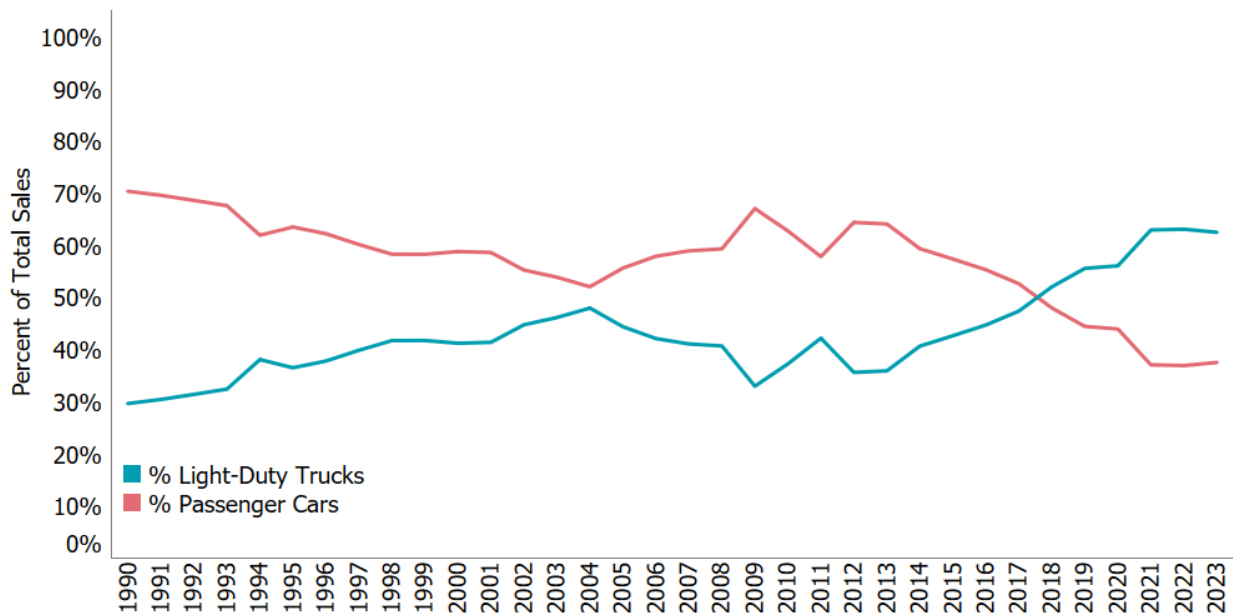
²³ Includes consumption of jet fuel and aviation gasoline. Does not include aircraft bunkers, which are not included in national emission totals, in line with IPCC methodological guidance.

1 **Figure 3-15: Sales-Weighted Fuel Economy of New Passenger Cars and Light-Duty Trucks, 1990–2023**
 2



3
 4 Source: EPA (2023).

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



6
 7 Source: EPA (2023).

1 **Table 3-13: CO₂ Emissions from Fossil Fuel Combustion in Transportation End-Use**
 2 **Sector (MMT CO₂ 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	471.2
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	7.6
<i>International Bunker Fuels^e</i>	<i>11.7</i>	<i>9.5</i>	<i>10.1</i>	<i>7.8</i>	<i>7.4</i>	<i>7.2</i>	<i>7.1</i>
Jet Fuel	184.1	189.2	180.3	120.6	152.6	164.8	178.8
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	12.0
General Aviation Aircraft	38.5	36.8	31.4	17.6	21.1	22.7	37.1
<i>International Bunker Fuels^e</i>	<i>38.2</i>	<i>60.2</i>	<i>78.3</i>	<i>39.8</i>	<i>50.8</i>	<i>66.6</i>	<i>66.6</i>
<i>International Bunker Fuels from Commercial Aviation</i>	<i>30.0</i>	<i>55.6</i>	<i>75.1</i>	<i>36.7</i>	<i>47.6</i>	<i>63.5</i>	<i>63.5</i>
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
<i>International Bunker Fuels^e</i>	<i>53.7</i>	<i>43.6</i>	<i>25.2</i>	<i>22.1</i>	<i>21.9</i>	<i>24.4</i>	<i>22.7</i>
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	+	+	+	+	+
Medium- and Heavy-Duty Trucks ^b	1.3	0.9	0.1	0.1	0.1	0.1	0.1
Buses	+	0.7	0.6	0.5	0.5	0.6	0.6
Electricityⁱ	3.0	4.7	4.2	3.5	3.9	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	1,781.3
<i>International Bunker Fuels</i>	103.6	113.3	113.6	69.6	80.2	98.2	96.4
<i>Biofuels-Ethanol^k</i>	4.1	21.6	78.7	68.1	75.4	75.0	76.4
<i>Biofuels-Biodiesel^k</i>	0.0	0.9	17.1	17.7	16.1	15.6	18.2

+ Does not exceed 0.05 MMT CO₂ 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 CO₂ 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, CO₂ 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 CO₂ emissions from U.S. Territories, since these are covered in a separate chapter of the Inventory. Totals may not sum due to independent rounding.

33 **Mobile Fossil Fuel Combustion CH₄ and N₂O Emissions**

34 Mobile combustion includes emissions of CH₄ and N₂O from all transportation sources identified in the
35 U.S. *Inventory* with the exception of pipelines and electric locomotives;²⁴ mobile sources also include
36 non-transportation sources such as construction/mining equipment, agricultural equipment, vehicles
37 used off-road, and other sources (e.g., snowmobiles, lawnmowers, etc.).²⁵ Annex 3.2 includes a

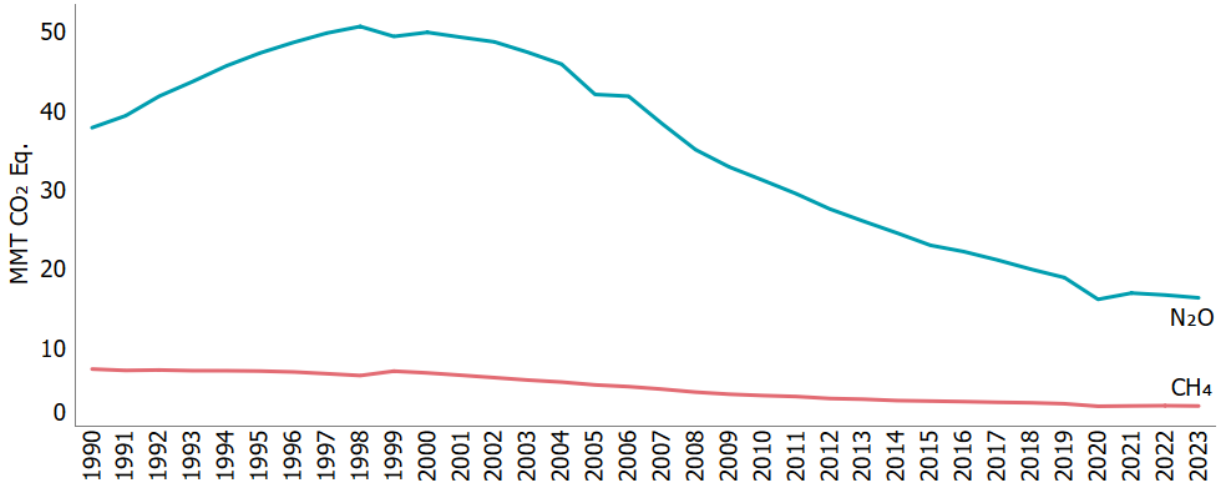
²⁴ Emissions of CH₄ from natural gas systems are reported separately. More information on the methodology used to calculate these emissions are included in this chapter and Annex 3.4.

²⁵ See the methodology sub-sections of the CO₂ from Fossil Fuel Combustion and CH₄ and N₂O from Mobile Combustion sections of this chapter. Note that N₂O and CH₄ emissions are reported using different categories than CO₂. CO₂ emissions are reported by end-use sector (transportation, industrial, commercial, residential, U.S. Territories), and generally adhere to a top-down approach to estimating emissions. CO₂ emissions from non-transportation mobile sources (e.g., lawn and garden equipment, farm equipment, construction equipment) are allocated to their respective end-use sector (i.e., construction equipment CO₂ emissions are included in the Industrial end-use sector instead of the

1 summary of all emissions from both transportation and mobile sources. Table 3-14 and Table 3-15
 2 provide mobile fossil fuel CH₄ and N₂O emission estimates in MMT CO₂ Eq.²⁶

3 Mobile combustion was responsible for a small portion of national CH₄ emissions (0.4 percent) and was
 4 the fifth largest source of national N₂O emissions (4.2 percent) in 2023. From 1990 to 2023, mobile
 5 source CH₄ emissions declined by 65 percent, to 2.6 MMT CO₂ Eq. (91 kt), due largely to emissions
 6 control technologies employed in on-road vehicles since the mid-1990s to reduce CO, NO_x, NMVOC,
 7 and CH₄ emissions. Mobile source emissions of N₂O decreased by 57.5 percent, to 16.2 MMT CO₂ Eq.
 8 (61 kt) in 2023. Earlier generation control technologies initially resulted in elevated N₂O emissions,
 9 causing a 32 percent increase in N₂O emissions from mobile sources between 1990 and 1997.
 10 Improvements in later-generation emission control technologies have reduced N₂O output, resulting in a
 11 67 percent decrease in mobile source N₂O emissions from 1997 to 2023 (see Figure 3-17). Overall, CH₄
 12 and N₂O emissions were predominantly from gasoline-fueled passenger cars, light-duty trucks, and
 13 non-highway sources. See Annex 3.2 for data by vehicle mode and information on VMT and the share of
 14 new vehicles.

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



17 **Table 3-14: CH₄ Emissions from Mobile Combustion (MMT CO₂ 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

transportation end-use sector). CH₄ and N₂O emissions are reported using the “mobile combustion” category, which includes non-transportation mobile sources. CH₄ and N₂O emission estimates are bottom-up estimates, based on total activity (fuel use, VMT) and emissions factors by source and technology type. These reporting schemes are in accordance with IPCC guidance. For informational purposes only, CO₂ emissions from non-transportation mobile sources are presented separately from their overall end-use sector in Annex 3.2.

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	+	+	0.1	+	+	+	+
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	2.6

1 + Does not exceed 0.05 MMT CO₂ Eq.

2 ^a See Annex 3.2 for definitions of on-road vehicle types.

3 ^b Gasoline and diesel highway vehicle mileage estimates are based on data from FHWA Highway Statistics Table VM-1. VMT for
4 2023 is based on FHWA's Traffic Volume Trends data series. VMT estimates from FHWA are allocated to vehicle type using ratios
5 of VMT per vehicle type to total VMT, derived from EPA's MOVES5 model (see Annex 3.2 for information about the MOVES model).

6 ^c Nonroad fuel consumption estimates for 2020 are adjusted to account for the COVID-19 pandemic and associated restrictions.
7 For agricultural equipment and airport equipment, sector specific adjustment factors were applied to the 2019 data. For all other
8 sectors, a 7.7 percent reduction factor is used, based on transportation diesel use (EIA 2024).

9 ^d Rail emissions do not include emissions from electric powered locomotives. Class II and Class III diesel consumption data for
10 2014 to 2023 is estimated by applying the historical average fuel usage per carload factor to the annual number of carloads.

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

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

15 ^g "Other" includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad
16 equipment, airport equipment, commercial equipment, and industrial equipment, as well as fuel consumption from trucks that
17 are used off-road for commercial/industrial purposes.

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

19 **Table 3-15: N₂O Emissions from Mobile Combustion (MMT CO₂ 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	16.1	16.8	16.6	16.2

+ Does not exceed 0.05 MMT CO₂ Eq.

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

^b Gasoline and diesel highway vehicle mileage estimates are based on data from FHWA Highway Statistics Table VM-1. 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 2023).

^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.

CO₂ from Fossil Fuel Combustion

Methodology and Time-Series Consistency

CO₂ emissions from fossil fuel combustion are estimated in line with a Tier 2 method described by the IPCC in the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC 2006) 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 2024a). 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 2024b), 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 CO₂ Eq. in 2023.

1 format are presented “top down”—that is, energy consumption for fuel types and categories are
2 estimated from energy production data (accounting for imports, exports, stock changes, and
3 losses). The resulting quantities are referred to as “apparent consumption.” The data collected
4 in the United States by EIA on an annual basis and used in this *Inventory* are predominantly from
5 mid-stream or conversion energy consumers such as refiners and electric power generators.
6 These annual surveys are supplemented with end-use energy consumption surveys, such as the
7 Manufacturing Energy Consumption Survey, that are conducted on a periodic basis (every four
8 years). These consumption datasets help inform the annual surveys to arrive at the national
9 total and sectoral breakdowns for that total.²⁹

- 10 3. Also, note that U.S. fossil fuel energy statistics are generally presented using gross calorific
11 values (GCV) (i.e., higher heating values). Fuel consumption activity data presented here have
12 not been adjusted to correspond to international standards, which are to report energy statistics
13 in terms of net calorific values (NCV) (i.e., lower heating values).³⁰
- 14 4. *Subtract uses accounted for in the Industrial Processes and Product Use chapter.* Portions of
15 the fuel consumption data for seven fuel categories—coking coal, distillate fuel, industrial other
16 coal, petroleum coke, natural gas, residual fuel oil, and other oil—were reallocated to the
17 Industrial Processes and Product Use chapter, as they were consumed during non-energy-
18 related industrial activity. To make these adjustments, additional data were collected from AISI
19 (2004 through 2021), Coffeyville (2012), U.S. Census Bureau (2001 through 2011), EIA (2024a,
20 2024f, 2024h), USAA (2008 through 2021), USGS (1991 through 2020), (USGS 2019), USGS (2014
21 through 2021a), USGS (2014 through 2021b), USGS (1995 through 2013), USGS (1995, 1998,
22 2000, 2001, 2002, 2007), USGS (2021a), USGS (1991 through 2015a), USGS (1991 through
23 2020), USGS (2014 through 2021a), USGS (1991 through 2015b), USGS (2021b), USGS (1991
24 through 2020).³¹
- 25 5. *Adjust for biofuels and petroleum denaturant.* Fossil fuel consumption estimates are adjusted
26 downward to exclude fuels with biogenic origins and avoid double counting in petroleum data
27 statistics. Carbon dioxide emissions from ethanol added to motor gasoline and biodiesel added
28 to diesel fuel are not included specifically in summing energy sector totals. Net carbon fluxes
29 from changes in biogenic carbon reservoirs are accounted for in the estimates for LULUCF,
30 therefore, fuel consumption estimates are adjusted to remove ethanol and biodiesel.³² For the
31 years 1993 through 2008, petroleum denaturant is currently included in EIA statistics for both
32 natural gasoline and finished motor gasoline. To avoid double counting, petroleum denaturant is
33 subtracted from finished motor gasoline for these years.³³
- 34 6. *Adjust for CO₂ sequestration.* Since October 2000, the Dakota Gasification Plant has been
35 exporting CO₂ produced in the coal gasification process to Canada by pipeline. Because this

²⁹ See IPCC Reference Approach for Estimating CO₂ Emissions from Fossil Fuel Combustion in Annex 4 for a comparison of U.S. estimates using top-down and bottom-up approaches.

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.

1 CO₂ is not emitted to the atmosphere in the United States, the associated fossil fuel (lignite
2 coal) that is gasified to create the exported CO₂ is subtracted from EIA (2024h) coal
3 consumption statistics that are used to calculate greenhouse gas emissions from the Energy
4 Sector. The associated fossil fuel is the total fossil fuel burned at the plant with the CO₂ capture
5 system multiplied by the fraction of the plant's total site-generated CO₂ that is recovered by the
6 capture system. To make these adjustments, data for CO₂ exports were collected from
7 Environment and Climate Change Canada (2022). A discussion of the methodology used to
8 estimate the amount of CO₂ captured and exported by pipeline is presented in Annex 2.1.

9 Additionally in 2023, the Petra Nova facility reported to the GHGRP subpart RR sequestration of
10 CO₂ that was captured from a coal fired power plant. Because the sequestered CO₂ is assumed
11 to not be admitted to the atmosphere, the CO₂ captured for sequestration was needed out of
12 CO₂ emissions from electric power sector coal. See Section 3.9 for more information on CO₂
13 transport, injection and geological storage accounting in the Inventory.

14 7. *Adjust sectoral allocation of distillate fuel oil and motor gasoline.* EPA conducted a separate
15 bottom-up analysis of transportation fuel consumption based on data from the Federal Highway
16 Administration that indicated that the amount of distillate and motor gasoline consumption
17 allocated to the transportation sector in the EIA statistics should be adjusted. Therefore, for
18 these estimates, the transportation sector's distillate fuel and motor gasoline consumption
19 were adjusted to match the value obtained from the bottom-up analysis. As the total distillate
20 and motor gasoline consumption estimate from EIA are considered to be accurate at the
21 national level, the distillate and motor gasoline consumption totals for the residential,
22 commercial, and industrial sectors were adjusted proportionately. The data sources used in the
23 bottom-up analysis of transportation fuel consumption include AAR (2008 through 2022),
24 Benson (2002 through 2004), DOE (1993 through 2020), EIA (2007), EIA (2024a), EPA (2024b),
25 and FHWA (1996 through 2023).³⁴

26 8. *Adjust for fuels consumed for non-energy uses.* U.S. aggregate energy statistics include
27 consumption of fossil fuels for non-energy purposes. These are fossil fuels that are
28 manufactured into plastics, asphalt, lubricants, or other products. Depending on the end-use,
29 this can result in storage of some or all of the carbon contained in the fuel for a period of time.
30 As the emission pathways of carbon used for non-energy purposes are vastly different than fuel
31 combustion (since the carbon in these fuels ends up in products instead of being combusted),
32 these emissions are estimated separately in Section 3.2. Therefore, the amount of fuels used for
33 non-energy purposes was subtracted from total fuel consumption. Data on non-fuel
34 consumption were provided by EIA (2024a).

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

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 2022).

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

1 Defense (Installations and Environment) and the Defense Logistics Agency Energy (DLA Energy)
2 of the U.S. Department of Defense (DoD) (DLA Energy 2022) supplied data on military jet fuel
3 and marine fuel use. Commercial jet fuel use was estimated based on data from FAA (2024) and
4 DOT (1991 through 2023); residual and distillate fuel use for civilian marine bunkers was
5 obtained from DOC (1991 through 2023) for 1990 through 2001 and 2007 through 2020, and
6 DHS (2008) for 2003 through 2006.³⁶ Consumption of these fuels was subtracted from the
7 corresponding fuels totals in the transportation end-use sector. Estimates of international
8 bunker fuel emissions for the United States are discussed in detail in Section 3.9.

9 10. *Determine the total carbon content of fuels consumed.* Total carbon was estimated by
10 multiplying the amount of fuel consumed by the amount of carbon in each fuel. This total
11 carbon estimate defines the maximum amount of carbon that could potentially be released to
12 the atmosphere if all of the carbon in each fuel was converted to CO₂. A discussion of the
13 methodology and sources used to develop the carbon content coefficients are presented in
14 Annexes 2.1 and 2.2.

15 11. *Estimate CO₂ Emissions.* Total CO₂ emissions are the product of the adjusted energy
16 consumption (from the previous methodology steps 1 through 7), the carbon content of the
17 fuels consumed, and the fraction of carbon that is oxidized. The fraction oxidized was assumed
18 to be 100 percent for petroleum, coal, and natural gas based on guidance in IPCC (2006) (see
19 Annex 2.1). Carbon emissions were multiplied by the molecular-to-atomic weight ratio of CO₂ to
20 carbon (44/12) to obtain total CO₂ emitted from fossil fuel combustion in million metric tons
21 (MMT).

22 12. *Allocate transportation emissions by vehicle type.* This report provides a more detailed
23 accounting of emissions from transportation because it is such a large consumer of fossil fuels
24 in the United States. For fuel types other than jet fuel, fuel consumption data by vehicle type and
25 transportation mode were used to allocate emissions by fuel type calculated for the
26 transportation end-use sector. Heat contents and densities were obtained from EIA (2024f) and
27 USAF (1998).³⁷

- 28 • For on-road vehicles, annual estimates of combined motor gasoline and diesel fuel
29 consumption by vehicle category were obtained from FHWA (1996 through 2023); for each
30 vehicle category, the percent gasoline, diesel, and other (e.g., CNG, LPG) fuel consumption
31 are estimated using data from EPA's MOVES model and DOE (1993 through 2022).^{38,39}

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 CO₂) and International Bunker Fuels sections of the Energy chapter, Annex 3.2, and Annex 3.8, 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 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). 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 (2024a). In previous Inventory years, data from DOE (1993 through 2023) 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.

- 1 • For non-road vehicles, activity data were obtained from AAR (2008 through 2022), APTA
2 (2007 through 2023), APTA (2006), BEA (1991 through 2015), Benson (2002 through 2004),
3 DLA Energy (2022), DOC (1991 through 2023), DOE (1993 through 2022), DOT (1991 through
4 2023, EIA (2009a), EIA (2024h), EIA (2002), EIA (1991 through 2022), EPA (2024b),⁴⁰ and
5 Gaffney (2007).
- 6 • For jet fuel used by aircraft, CO₂ emissions from commercial aircraft were developed by the
7 U.S. Federal Aviation Administration (FAA) using a Tier 3B methodology, consistent IPCC
8 (2006) (see Annex 3.3). Carbon dioxide emissions from other aircraft were calculated
9 directly based on reported consumption of fuel as reported by EIA. Allocation to domestic
10 military uses was made using DoD data (see Annex 3.8). General aviation jet fuel
11 consumption is calculated as the remainder of total jet fuel use (as determined by EIA) nets
12 all other jet fuel use as determined by FAA and DoD. For more information, see Annex 3.2.

13 Methodological recalculations were applied to the entire time series to ensure time-series consistency
14 from 1990 through 2023. Due to data availability and sources, some adjustments outlined in the
15 methodology above are not applied consistently across the full 1990 to 2023 time series. As described
16 in greater detail in Annex 2.1, to align with EIA’s methodology for calculating motor gasoline
17 consumption, petroleum denaturant adjustments are applied to motor gasoline consumption only for
18 the period 1993 through 2008. In addition to ensuring time-series consistency, to ensure consistency in
19 reporting between the *Inventory* and the Canadian National Greenhouse Gas Inventory, the amount of
20 associated fossil fuel (lignite coal) that is gasified to create the exported CO₂ from the Dakota
21 Gasification Plant is adjusted to align with the Canadian National Greenhouse Gas Inventory
22 (Environment and Climate Change Canada 2022). This adjustment is explained in greater detail in Annex
23 2.1. As discussed in Annex 5, data are unavailable to include estimates of CO₂ emissions from any liquid
24 fuel used in pipeline transport or non-hazardous industrial waste incineration, but those emissions are
25 assumed to be insignificant.

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

27 The amount of carbon emitted from the combustion of fossil fuels is dependent upon the carbon
28 content of the fuel and the fraction of that carbon that is oxidized. Fossil fuels vary in their average
29 carbon content, ranging from about 53 MMT CO₂ Eq./QBtu for natural gas to upwards of 95 MMT CO₂
30 Eq./QBtu for coal and petroleum coke (see Tables A-42 and A-43 in Annex 2.1 for carbon contents of all
31 fuels). In general, the carbon content per unit of energy of fossil fuels is the highest for coal products,
32 followed by petroleum, and then natural gas. The overall carbon intensity of the U.S. economy is thus
33 dependent upon the quantity and combination of fuels and other energy sources employed to meet
34 demand.

35 Table 3-16 provides a time series of the carbon intensity of direct emissions for each sector of the U.S.
36 economy. The time series incorporates only the energy from the direct combustion of fossil fuels in each
37 sector. For example, the carbon intensity for the residential sector does not include the energy from or
38 emissions related to the use of electricity for lighting, as it is instead allocated to the electric power
39 sector. For the purposes of maintaining the focus of this section, renewable energy and nuclear energy
40 are not included in the energy totals used in Table 3-16 in order to focus attention on fossil fuel
41 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.

1 residential sector exhibited the lowest carbon intensity, which is related to the large percentage of its
 2 energy derived from natural gas for heating. The carbon intensity of the commercial sector has
 3 predominantly declined since 1990 as commercial businesses shift from petroleum to natural gas. The
 4 industrial sector was more dependent on petroleum and coal than either the residential or commercial
 5 sectors, and thus had higher carbon intensities over this period. The carbon intensity of the
 6 transportation sector was closely related to the carbon content of petroleum products (e.g., motor
 7 gasoline and jet fuel, both around 70 MMT CO₂ Eq./QBtu), which were the primary sources of energy.
 8 Lastly, the electric power sector had the highest carbon intensity due to its heavy reliance on coal for
 9 generating electricity.

10 **Table 3-16: Carbon Intensity from Direct Fossil Fuel Combustion by Sector (MMT CO₂**
 11 **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

12 ^a Does not include electricity or renewable energy consumption.

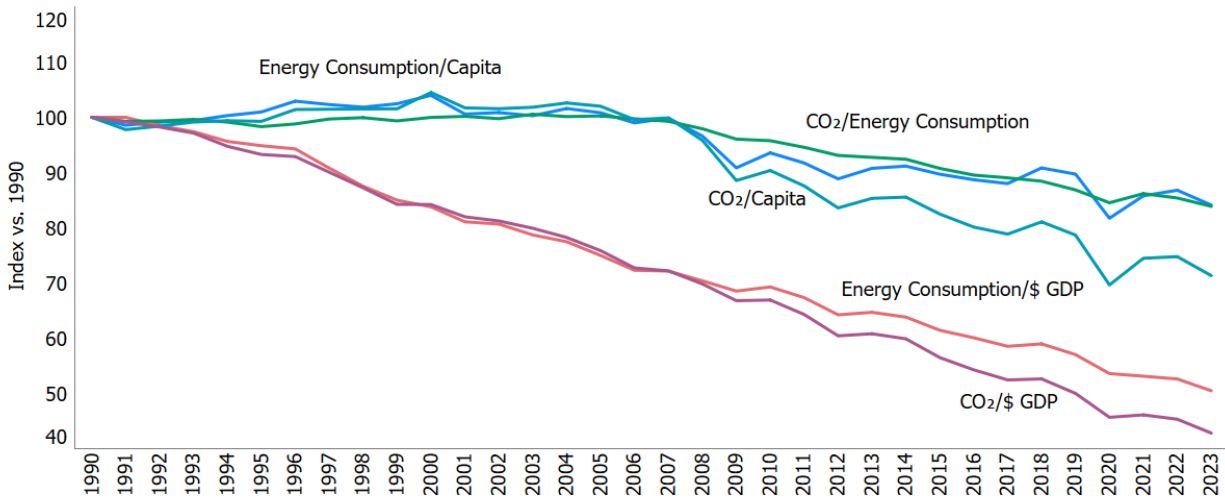
13 ^b Does not include electricity produced using nuclear or renewable energy.

14 ^c Does not include nuclear or renewable energy consumption.

15 Notes: Excludes non-energy fuel use emissions and consumption. Totals may not sum due to independent rounding.

16 For the time period of 1990 through about 2008, the carbon intensity of U.S. energy consumption was
 17 fairly constant, as the proportion of fossil fuels used by the individual sectors did not change
 18 significantly over that time. Starting in 2008 the carbon intensity of U.S. energy consumption has
 19 decreased, reflecting the shift from coal to natural gas in the electric power sector during that time
 20 period. Per capita energy consumption fluctuated little from 1990 to 2007, but then started decreasing
 21 after 2007 and, in 2023, was approximately 15.8 percent below levels in 1990 (see Table 3-17). To
 22 differentiate these estimates from those of Table 3-16, the carbon intensity trend shown in Table 3-17
 23 and described below includes nuclear and renewable energy EIA data to provide a comprehensive
 24 economy-wide picture of energy consumption. Due to a general shift from a manufacturing-based
 25 economy to a service-based economy, as well as overall increases in efficiency, energy consumption
 26 and energy-related CO₂ emissions per dollar of gross domestic product (GDP) have both declined since
 27 1990 (BEA 2024).

Table 3-17: U.S. Energy Consumption and Energy-Related CO₂ Emissions Per Capita and Per Dollar GDP



Carbon intensity estimates were developed using nuclear and renewable energy data from EIA (2023c), EPA (2010), and fossil fuel consumption data as discussed above and presented in Annex 2.1.

Uncertainty

For estimates of CO₂ from fossil fuel combustion, the amount of CO₂ 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 CO₂ 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 CO₂ 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.

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

8 Various sources of uncertainty surround the estimation of emissions from international bunker fuels,
9 which are subtracted from the U.S. totals (see the detailed discussions on these uncertainties provided
10 in Section 3.9). Another source of uncertainty is fuel consumption by U.S. Territories. The United States
11 does not collect energy statistics for its territories at the same level of detail as for the fifty states and
12 the District of Columbia. Therefore, estimating both emissions and bunker fuel consumption by these
13 territories is difficult.

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

19 The uncertainty analysis was performed by primary fuel type for each end-use sector, using the IPCC-
20 recommended Approach 2 uncertainty estimation methodology, Monte Carlo stochastic simulation
21 technique, with @RISK software. For this uncertainty estimation, the inventory estimation model for CO₂
22 from fossil fuel combustion was integrated with the relevant variables from the inventory estimation
23 model for International Bunker Fuels, to realistically characterize the interaction (or endogenous
24 correlation) between the variables of these two models. About 170 input variables were modeled for
25 CO₂ from energy-related fossil fuel combustion (including about 20 for non-energy fuel consumption
26 and about 20 for International Bunker Fuels).

27 In developing the uncertainty estimation model, uniform distributions were assumed for all activity-
28 related input variables and emission factors, based on the SAIC/EIA (2001) report.⁴¹ Triangular
29 distributions were assigned for the oxidization factors (or combustion efficiencies). The uncertainty
30 ranges were assigned to the input variables based on the data reported in SAIC/EIA (2001) and on
31 conversations with various agency personnel.⁴²

32 The uncertainty ranges for the activity-related input variables were typically asymmetric around their
33 inventory estimates; the uncertainty ranges for the emissions factors were symmetric. Bias (or
34 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.

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

3 The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-18. Fossil fuel
4 combustion CO₂ emissions in 2023 were estimated to be between 4,462.0 and 4,753.7 MMT CO₂ Eq. at a
5 95 percent confidence level. This indicates a range of 2 percent below to 4 percent above the 2023
6 emission estimate of 4,559.4 MMT CO₂ Eq.

7 **Table 3-18: Approach 2 Quantitative Uncertainty Estimates for CO₂ Emissions from**
8 **Energy-Related Fossil Fuel Combustion by Fuel Type and Sector (MMT CO₂ Eq. and**
9 **Percent)**

Fuel/Sector	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^b	735.0	710.1	803.4	-3%	9%
Residential	NO	0.0	0.0	0.0	0.0
Commercial	1.1	1.1	1.3	-5%	15%
Industrial	36.0	34.3	42.7	-5%	16%
Transportation	NO	NO	NO	NO	NO
Electric Power	694.9	668.3	761.3	-4%	10%
U.S. Territories	2.9	2.6	3.5	-12%	19%
Natural Gas^b	1,725.8	1,704.5	1,805.3	-1%	5%
Residential	247.5	240.5	264.8	-3%	7%
Commercial	182.8	177.7	195.7	-3%	7%
Industrial	514.8	498.0	552.6	-3%	7%
Transportation	71.7	69.7	76.8	-3%	7%
Electric Power	704.5	684.2	740.7	-3%	5%
U.S. Territories	4.5	3.9	5.2	-12%	17%
Petroleum^b	2,098.3	1,972.0	2,221.0	-6%	6%
Residential	59.6	56.3	62.8	-6%	5%
Commercial	60.2	56.9	63.3	-5%	5%
Industrial	241.3	186.3	296.7	-23%	23%
Transportation	1,704.5	1,597.0	1,809.6	-6%	6%
Electric Power	14.7	14.1	15.7	-4%	7%
U.S. Territories	17.8	16.6	19.7	-7%	11%
Geothermal	0.4	0.2	1.1	-45%	188%
Electric Power	0.4	0.2	1.1	-45%	188%
Total (including Geothermal)^b	4,559.4	4,462.0	4,753.7	-2%	4%

10 NO (Not Occurring)

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

12 ^b The low and high estimates for total emissions were calculated separately through simulations and, hence, the low and high
13 emission estimates for the sub-source categories do not sum to total emissions.

14 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.

1 **QA/QC and Verification**

2 In order to ensure the quality of the CO₂ emission estimates from fossil fuel combustion, general (IPCC
 3 Tier 1) and category-specific (Tier 2) Quality Assurance/Quality Control (QA/QC) procedures were
 4 implemented consistent with the U.S. Inventory QA/QC plan outlined in Annex 8. The Tier 2 procedures
 5 that were implemented involved checks specifically focusing on the activity data and methodology used
 6 for estimating CO₂ emissions from fossil fuel combustion in the United States. Emission totals for the
 7 different sectors and fuels were compared and trends were investigated to determine whether any
 8 corrective actions were needed. Minor corrective actions were taken.

9 One area of QA/QC and verification is to compare the estimates and emission factors used in the
 10 *Inventory* with other sources of CO₂ emissions reporting. Two main areas and sources of data were
 11 considered. The first is a comparison with the EPA GHGRP combustion data (Subpart C) for stationary
 12 combustion sources excluding the electric power sector. This mainly focused on considering carbon
 13 factors for natural gas. The second comparison is with the EPA Air Markets Program data for electric
 14 power production. This considered carbon factors for coal and natural gas used in electric power
 15 production.

16 The EPA GHGRP collects greenhouse gas emissions data from large emitters including information on
 17 fuel combustion. This excludes emissions from mobile sources and smaller residential and commercial
 18 sources, those emissions are covered under supplier reporting (Subparts MM and NN) and are areas for
 19 further research. Fuel combustion CO₂ data reported in 2023 was 1,969.1 MMT CO₂. Of that, 1,465.2
 20 MMT CO₂ was from electricity production. Therefore, the non-electric power production fuel
 21 combustion reporting was a fraction of the total covered by the *Inventory* under fossil fuel combustion.
 22 Furthermore, reporters under the GHGRP can use multiple methods of calculating emissions; one
 23 method is to use the default emission factors provided in the rule, while another is based on a Tier 3
 24 approach using their own defined emission factors. Based on data from reporters on approach used, it
 25 was determined that only about 10 percent of natural gas combustion emissions were based on a Tier 3
 26 approach. Given the small sample size compared to the overall *Inventory* calculations for natural gas
 27 combustion EPA determined it was not reasonable to consider the GHGRP Tier 3 natural gas factors at
 28 this time. A more detailed analysis was done on upstream oil and gas natural gas combustion emissions
 29 using the GHGRP data as discussed in Annex 2.2.

30 EPA collects detailed sulfur dioxide (SO₂), nitrogen oxides (NO_x), and carbon dioxide (CO₂) emissions
 31 data and other information from power plants across the country as part of the Acid Rain Program (ARP),
 32 the Cross-State Air Pollution Rule (CSAPR), the CSAPR Update, and the Revised CSAPR Update (RCU).
 33 The CO₂ data from these Air Market Programs (AMP) can be compared to the electric power sector
 34 emissions calculated from the *Inventory* as shown in Table 3-19 for the three most recent years of data.

35 **Table 3-19: Comparison of Electric Power Sector Emissions (MMT CO₂ Eq. and Percent)**

Fuel/Sector	CO ₂ Emissions (MMT CO ₂ Eq.)			% Change	
	2021	2022	2023	21-22	22-23
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	21-22	22-23
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 CO₂ 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 CO₂ Eq./QBtu by multiplying the emission factor by 44/12, the molecular-to-atomic weight ratio of CO₂ to C. This would assume the fraction oxidized to be 100 percent, which is the guidance in IPCC (2006) (see Annex 2.1).

1 kept in fuel stocks, or left unoxidized in ash) or combusted, and therefore the carbon in them is oxidized
2 and released into the atmosphere. In the reference approach, accounting for actual consumption of
3 fuels at the sectoral or sub-national level is not required. One difference between the two approaches is
4 that emissions from carbon that was not stored during non-energy use of fuels are subtracted from the
5 sectoral approach and reported separately (see Section 3.2). These emissions, however, are not
6 subtracted in the reference approach. As a result, the reference approach emission estimates are
7 comparable to those of the sectoral approach, with the exception that the non-energy use (NEU) source
8 category emissions are included in the reference approach (see Annex 4 for more details).

9 **Recalculations Discussion**

10 EIA (2024a) updated natural gas consumed by all sectors in 2020 and 2022, as well as petroleum
11 consumed by all sectors in 2021 and 2022. Additionally, EIA (2024b) updated U.S. Territories petroleum
12 for the years 2020 through 2022, and U.S. Territories natural gas and coal consumption for the year 2022.
13 EPA also updated the methodology for estimating the consumption of other petroleum liquids by U.S.
14 Pacific Islands and Wake Island for years 2020 through 2022 to fill data gaps in the publication. These
15 years are now proxied to 2019. These updates caused total CO₂ emissions to increase by an annual
16 average of 0.1 MMT CO₂ Eq. (less than 0.05 percent) in the years 1990 through 2022 compared to the
17 previous *Inventory*.

18 **Planned Improvements**

19 To reduce the uncertainty of CO₂ from fossil fuel combustion estimates for U.S. Territories, further expert
20 elicitation may be conducted to better quantify the total uncertainty associated with emissions from
21 U.S. Territories. Additionally, although not technically a fossil fuel, since geothermal energy-related CO₂
22 emissions are included for reporting purposes, further expert elicitation may be conducted to better
23 quantify the total uncertainty associated with CO₂ emissions from geothermal energy use.

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

38 Additional analyses will be conducted to align reported facility-level fuel types and IPCC fuel types per
39 the national energy statistics. For example, additional work will look at CO₂ emissions from biomass to
40 ensure they are separated in the facility-level reported data and maintaining consistency with national
41 energy statistics provided by EIA. In implementing improvements and integration of data from EPA's

1 GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will
2 continue to be relied upon.⁴⁵

3 EPA is also evaluating the methods used to adjust for conversion of fuels and exports of CO₂. EPA is
4 including an approach used to account for CO₂ transport, injection, and geological storage in this
5 *Inventory*, as part of this ongoing work there may be changes made to the accounting for CO₂ exports.

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

12 CH₄ and N₂O from Stationary Combustion

13 Methodology and Time-Series Consistency

14 Methane and N₂O emissions from stationary combustion were estimated by multiplying fossil fuel and
15 wood consumption data by emission factors (by sector and fuel type for industrial, residential,
16 commercial, and U.S. Territories; and by fuel and technology type for the electric power sector). The
17 electric power sector utilizes a Tier 2 methodology, whereas all other sectors utilize a Tier 1
18 methodology in accordance with IPCC methodological decision tree Figure 2.1 in the *2006 IPCC*
19 *Guidelines for National Greenhouse Gas Inventories* (IPCC 2006) and available data. The activity data
20 and emission factors used are described in the following subsections.

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

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

24 National coal, natural gas, fuel oil, and wood consumption data were grouped by sector: industrial,
25 commercial, residential, and U.S. Territories. For the CH₄ and N₂O emission estimates, consumption
26 data for each fuel were obtained from EIA's *Monthly Energy Review* (EIA 2024a). Because the United
27 States does not include territories in its national energy statistics, fuel consumption data for territories
28 were provided separately by EIA's International Energy Statistics (EIA 2024b).⁴⁶ Fuel consumption for the
29 industrial sector was adjusted to subtract out mobile source construction and agricultural use, which is
30 reported under mobile sources. Construction and agricultural mobile source fuel use was obtained from
31 EPA (2024b) and FHWA (1996 through 2023). Estimates for wood biomass consumption for fuel
32 combustion do not include municipal solid waste, tires, etc., that are reported as biomass by EIA. Non-
33 CO₂ emissions from combustion of the biogenic portion of municipal solid waste and tires is included
34 under waste incineration (Section 3.2). Estimates for natural gas combustion do not include biogas, and
35 therefore non-CO₂ emissions from biogas are not included (see the Planned Improvements section,
36 below). Tier 1 default emission factors for the industrial, commercial, and residential end-use sectors

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

⁴⁶ U.S. Territories data also include combustion from mobile activities because data to allocate territories' energy use were unavailable. For this reason, CH₄ and N₂O emissions from combustion by U.S. Territories are only included in the stationary combustion totals.

1 were provided by the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006). U.S.
2 Territories' emission factors were estimated using the U.S. emission factors for the primary sector in
3 which each fuel was combusted.

4 **Electric Power Sector**

5 The electric power sector uses a Tier 2 emission estimation methodology as fuel consumption for the
6 electric power sector by control-technology type is based on EPA's Acid Rain Program Dataset (EPA
7 2024). Total fuel consumption in the electric power sector from EIA (2024a) was apportioned to each
8 combustion technology type and fuel combination using a ratio of fuel consumption by technology type
9 derived from EPA (2024a) data. The combustion technology and fuel use data by facility obtained from
10 EPA (2024a) were only available from 1996 to 2023 so the consumption estimates from 1990 to 1995
11 were estimated by applying the 1996 consumption ratio by combustion technology type from EPA
12 (2024a) to the total EIA (2024a) consumption for each year from 1990 to 1995.

13 Emissions were estimated by multiplying fossil fuel and wood consumption by technology-, fuel-, and
14 country-specific Tier 2 emission factors. The Tier 2 emission factors used are based in part on emission
15 factors published by EPA, and EPA's Compilation of Air Pollutant Emission Factors, AP-42 (EPA 1997) for
16 coal wall-fired boilers, residual fuel oil, diesel oil and wood boilers, natural gas-fired turbines, and
17 combined cycle natural gas units.⁴⁷

18 As discussed in Annex 5, data are unavailable to include estimates of CH₄ and N₂O emissions from
19 biomass use in Territories, but those emissions are assumed to be insignificant.

20 **Uncertainty**

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

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

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

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.

1 In developing the uncertainty estimation model, uniform distribution was assumed for all activity-
 2 related input variables and N₂O emission factors, based on the SAIC/EIA (2001) report.⁴⁸ For these
 3 variables, the uncertainty ranges were assigned to the input variables based on the data reported in
 4 SAIC/EIA (2001).⁴⁹ However, the CH₄ emission factors differ from those used by EIA. These factors and
 5 uncertainty ranges are based on IPCC default uncertainty estimates (IPCC 2006).

6 The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-96. Stationary
 7 combustion CH₄ emissions in 2023 (including biomass) were estimated to be between 5.9 and 19.8
 8 MMT CO₂ Eq. at a 95 percent confidence level. This indicates a range of 33 percent below to 125 percent
 9 above the 2023 emission estimate of 8.8 MMT CO₂ Eq.⁵⁰ Stationary combustion N₂O emissions in 2023
 10 (including biomass) were estimated to be between 14.9 and 29.5 MMT CO₂ Eq. at a 95 percent
 11 confidence level. This indicates a range of 24 percent below to 51 percent above the 2023 emission
 12 estimate of 19.6 MMT CO₂ Eq.

13 **Table 3-21: Approach 2 Quantitative Uncertainty Estimates for CH₄ and N₂O Emissions**
 14 **from Energy-Related Stationary Combustion, Including Biomass (MMT CO₂ Eq. and**
 15 **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	5.9	19.8	-33%	125%
Stationary Combustion	N ₂ O	19.6	14.9	29.5	-24%	51%

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

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

23 **QA/QC and Verification**

24 In order to ensure the quality of the non-CO₂ emission estimates from stationary combustion, general
 25 (IPCC Tier 1) and category-specific (Tier 2) Quality Assurance/Quality Control (QA/QC) procedures were
 26 implemented consistent with the U.S. Inventory QA/QC plan outlined in Annex 8. The Tier 2 procedures
 27 that were implemented involved checks specifically focusing on the activity data and emission factor

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.
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.

1 sources and methodology used for estimating CH₄, N₂O, and the greenhouse gas precursors from
2 stationary combustion in the United States. Emission totals for the different sectors and fuels were
3 compared and trends were investigated.

4 **Recalculations Discussion**

5 EPA adjusted the share of total consumption apportioned to each combustion technology type for 2022
6 to correct a previous error. EIA (2024a) updated the heat constant of bituminous coal for the time series.
7 EIA (2024a) updated natural gas consumed by all sectors in 2020 and 2022, as well as petroleum
8 consumed by all sectors in 2021 and 2022. EIA (2024a) also updated electricity statistics which affected
9 commercial sector wood consumption for the years 2014 through 2022. Additionally, EIA (2024b)
10 updated U.S. Territories petroleum for the years 2020 through 2022, and U.S. Territories natural gas and
11 coal consumption for the year 2022. EPA also updated the methodology for estimating the consumption
12 of other petroleum liquids by U.S. Pacific Islands and Wake Island for years 2020 through 2022 to fill
13 data gaps in the publication. These years are now proxied to 2019. These updates resulted in an average
14 annual decrease of less than 0.5 MMT CO₂ Eq. (0.1 percent) in CH₄ emissions and an average annual
15 decrease of less than 0.05 MMT CO₂ Eq. (0.3 percent) in N₂O emissions across the time series compared
16 to the previous *Inventory*.

17 **Planned Improvements**

18 Several items are being evaluated to improve the CH₄ and N₂O emission estimates from stationary
19 combustion and to reduce uncertainty for U.S. Territories. Efforts will be taken to work with EIA and other
20 agencies to improve the quality of the U.S. Territories data. Because these data are not broken out by
21 stationary and mobile uses, further research will be aimed at trying to allocate consumption
22 appropriately. In addition, the uncertainty of biomass emissions will be further investigated because it
23 was expected that the exclusion of biomass from the estimates would reduce the uncertainty; and in
24 actuality the exclusion of biomass increases the uncertainty. The CH₄ emission factor for residential
25 wood combustion developed by NESCAUM (2024) will also be reviewed and potentially incorporated
26 based on this review. Factors for methane slip will also be reviewed. These improvements are not all-
27 inclusive but are part of an ongoing analysis and efforts to continually improve these stationary
28 combustion estimates from U.S. Territories.

29 Other forms of biomass-based gas consumption include biogas. As an additional planned
30 improvement, EPA will examine EIA and GHGRP data on biogas collected and burned for energy use and
31 determine if CH₄ and N₂O emissions from biogas can be included in future Inventories. EIA (2024a)
32 natural gas data already deducts biogas used in the natural gas supply, so no adjustments are needed to
33 the natural gas fuel consumption data to account for biogas.

34 **CH₄ and N₂O from Mobile Combustion**

35 **Methodology and Time-Series Consistency**

36 Estimates of CH₄ and N₂O emissions from mobile combustion were calculated by multiplying emission
37 factors by measures of activity for each fuel and vehicle type (e.g., light-duty gasoline trucks). Activity
38 data included vehicle miles traveled (VMT) for on-road vehicles and fuel consumption for non-road
39 mobile sources. The activity data and emission factors used in the calculations are described in the

1 subsections that follow. A complete discussion of the methodology used to estimate CH₄ and N₂O
2 emissions from mobile combustion and the emission factors used in the calculations is provided in
3 Annex 3.2.

4 **On-Road Vehicles**

5 Estimates of CH₄ and N₂O emissions from gasoline and diesel on-road vehicles are based on VMT and
6 emission factors (in grams of CH₄ and N₂O per mile) by vehicle type, fuel type, model year, and emission
7 control technology. Emission estimates for alternative fuel vehicles (AFVs) are based on VMT and
8 emission factors (in grams of CH₄ and N₂O per mile) by vehicle and fuel type.⁵¹

9 CH₄ and N₂O emissions factors by vehicle type and emission tier for newer (starting with model year
10 2004) on-road gasoline vehicles were calculated by Browning (2019) from annual vehicle certification
11 data compiled by EPA. CH₄ and N₂O emissions factors for older (model year 2003 and earlier) on-road
12 gasoline vehicles were developed by ICF (2004). These earlier emission factors were derived from EPA,
13 California Air Resources Board (CARB) and Environment and Climate Change Canada (ECCC) laboratory
14 test results of different vehicle and control technology types. The EPA, CARB and ECCC tests were
15 designed following the Federal Test Procedure (FTP). The procedure covers three separate driving
16 segments, since vehicles emit varying amounts of greenhouse gases depending on the driving segment.
17 These driving segments are: (1) a transient driving cycle that includes cold start and running emissions,
18 (2) a cycle that represents running emissions only, and (3) a transient driving cycle that includes hot start
19 and running emissions. For each test run, a bag was affixed to the tailpipe of the vehicle and the exhaust
20 was collected; the content of this bag was then analyzed to determine quantities of gases present. The
21 emissions characteristics of driving segment 2 tests were used to define running emissions. Running
22 emissions were subtracted from the total FTP emissions to determine start emissions. These were then
23 recombined to approximate average driving characteristics, based upon the ratio of start to running
24 emissions for each vehicle class from MOBILE6.2, an EPA emission factor model that predicts grams per
25 mile emissions of CO₂, CO, HC, NO_x, and PM from vehicles under various conditions.⁵²

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

29 CH₄ and N₂O emission factors for AFVs were developed based on the 2023 Greenhouse gases,
30 Regulated Emissions, and Energy use in Transportation (GREET) model (ANL 2023). For light-duty trucks,
31 EPA used travel fractions for LDT1 and LDT2 (MOVES Source Type 31 for LDT1 and MOVES Source Type
32 32 for LDT2; see Annex 3.2 for information about the MOVES model) to determine emission factors. For
33 medium-duty vehicles, EPA used emission factors for light heavy-duty vocational trucks. For heavy-duty
34 vehicles, EPA used emission factors for long-haul combination trucks. For buses, EPA used emission
35 factors for transit buses. These values represent vehicle operations only (tank-to-wheels); upstream
36 well-to-tank emissions are calculated elsewhere in the Inventory. Biodiesel CH₄ emission factors were
37 corrected from GREET values to be the same as CH₄ emission factors for diesel vehicles. GREET

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>.

1 overestimated biodiesel CH₄ emission factors based upon an incorrect CH₄-to-THC ratio for diesel
2 vehicles with aftertreatment technology.

3 Annual VMT data for 1990 through 2022 were obtained from the Federal Highway Administration's
4 (FHWA) Highway Performance Monitoring System database as reported in Highway Statistics (FHWA
5 1996 through 2023). VMT data for 2023 was proxied based on FHWA's Traffic Volume Trends Data for
6 2023. VMT estimates were then allocated to vehicle type using ratios of VMT per vehicle type to total
7 VMT, derived from EPA's MOVES5 model (see Annex 3.2 for information about the MOVES model). This
8 corrects time series inconsistencies in FHWA definitions of vehicle types (Browning 2022a). VMT for
9 alternative fuel vehicles (AFVs) were estimated based on Browning (2024). The age distributions of the
10 U.S. vehicle fleet were obtained from EPA (2004, 2024a), and the average annual age-specific vehicle
11 mileage accumulation of U.S. vehicles were obtained from EPA (2024a).

12 Control technology and standards data for on-road vehicles were obtained from EPA's Office of
13 Transportation and Air Quality (EPA 1998, 2022b, 2023, and 2024) and Browning (2005). These
14 technologies and standards are defined in Annex 3.2, and were compiled from EPA (1994a, 1994b, 1998,
15 1999) and IPCC (2006) sources.

16 **Non-Road Mobile Sources**

17 The nonroad mobile category for CH₄ and N₂O includes ships and boats, aircraft, locomotives, and other
18 mobile non-road sources (e.g., construction or agricultural equipment). For locomotives, aircraft, ships,
19 and non-recreational boats, fuel-based emission factors are applied to data on fuel consumption,
20 following the IPCC Tier 1 approach, The Tier 2 approach for these sources would require separate fuel-
21 based emissions factors by technology, for which data are not currently available. For other non-road
22 sources, EPA uses the Nonroad component of the MOVES model to estimate fuel use. Emission factors
23 by horsepower bin are estimated from EPA engine certification data. Because separate emission factors
24 are applied to specific engine technologies; these non-road sources utilize a Tier 2 approach.

25 To estimate CH₄ and N₂O emissions from non-road mobile sources, fuel consumption data were
26 employed as a measure of activity and multiplied by fuel-specific emission factors (in grams of N₂O and
27 CH₄ per kilogram of fuel consumed).⁵³ Activity data were obtained from AAR (2008 through 2024), APTA
28 (2007 through 2024), Rail Inc (2014 through 2024), APTA (2006), BEA (1991 through 2015), Benson (2002
29 through 2004), Bureau of Transportation Statistics (BTS; 2023), DLA Energy (2024), DOC (1991 through
30 2023), DOE (1993 through 2023), DOT (1991 through 2024), EIA (2002, 2007, 2024, 2023), EIA (1991
31 through 2023), EPA (2024a), Esser (2003 through 2004), FAA (2022), FHWA (1996 through 2023),⁵⁴
32 Gaffney (2007), FTA (2023), and Whorton (2006 through 2014). Fuel consumption data regarding jet fuel,
33 on-road vehicles, and diesel consumption in US territories and vessel bunking were proxied from 2022,

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 CH₄ and N₂O emissions for these categories. For agriculture, the MF-24 gasoline volume is used directly because it includes both non-road trucks and equipment. For construction and commercial/industrial category gasoline estimates, the 2014 and older MF-24 volumes represented non-road trucks only; therefore, the MOVES gasoline volumes for construction and commercial/industrial categories are added to the respective categories in the Inventory. Beginning in 2015, this addition is no longer necessary since the FHWA updated its methods for estimating on-road and non-road gasoline consumption. Among the method updates, FHWA now incorporates MOVES equipment gasoline volumes in the construction and commercial/industrial categories.

1 awaiting publication of updated data. Fuel consumption data for boats and vessels in U.S. Territories
 2 data and vessel domestic vessel bunkering is proxied from 2022 proxy data. Emission factors for non-
 3 road modes were taken from IPCC (2006) and Browning (2020 and 2018).

4 **Uncertainty**

5 A quantitative uncertainty analysis was conducted for the mobile source sector using the IPCC-
 6 recommended Approach 2 uncertainty estimation methodology, Monte Carlo stochastic simulation
 7 technique, using @RISK software. The uncertainty analysis was performed on 2023 estimates of CH₄
 8 and N₂O emissions, incorporating probability distribution functions associated with the major input
 9 variables. For the purposes of this analysis, the uncertainty was modeled for the following four major
 10 sets of input variables: (1) VMT data, by on-road vehicle and fuel type, (2) emission factor data, by on-
 11 road vehicle, fuel, and control technology type, (3) fuel consumption, data, by non-road vehicle and
 12 equipment type, and (4) emission factor data, by non-road vehicle and equipment type.

13 Uncertainty analyses were not conducted for NO_x, CO, or NMVOC emissions. Emission factors for these
 14 gases have been extensively researched because emissions of these gases from motor vehicles are
 15 regulated in the United States, and the uncertainty in these emission estimates is believed to be
 16 relatively low. For more information, see Section 3.11. However, a much higher level of uncertainty is
 17 associated with CH₄ and N₂O emission factors due to limited emission test data, and because, unlike
 18 CO₂ emissions, the emission pathways of CH₄ and N₂O are highly complex.

19 Based on the uncertainty analysis, mobile combustion CH₄ emissions from all mobile sources in 2023
 20 were estimated to be between 2.5 and 3.3 MMT CO₂ Eq. at a 95 percent confidence level. This indicates
 21 a range of 4 percent below to 30 percent above the corresponding 2023 emission estimate of 2.6 MMT
 22 CO₂ Eq. Mobile combustion N₂O emissions from mobile sources in 2023 were estimated to be between
 23 15.1 and 19.9 MMT CO₂ Eq. at a 95 percent confidence level. This indicates a range of 7 percent below
 24 to 22 percent above the corresponding 2023 emission estimate of 16.2 MMT CO₂ Eq.

25 **Table 3-22: Approach 2 Quantitative Uncertainty Estimates for CH₄ and N₂O Emissions**
 26 **from Mobile Sources (MMT CO₂ 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	2.6	2.5	3.3	-4%	+30%
Mobile Sources	N ₂ O	16.2	15.1	19.9	-7%	+22%

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

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

1 **QA/QC and Verification**

2 In order to ensure the quality of the emission estimates from mobile combustion, general (IPCC Tier 1)
3 and category-specific (Tier 2) Quality Assurance/Quality Control (QA/QC) procedures were
4 implemented consistent with the U.S. Inventory QA/QC plan outlined in Annex 8. The specific plan used
5 for mobile combustion was updated prior to collection and analysis of this current year of data. The Tier
6 2 procedures focused on the emission factor and activity data sources, as well as the methodology used
7 for estimating emissions. These procedures included a qualitative assessment of the emission
8 estimates to determine whether they appear consistent with the most recent activity data and emission
9 factors available. A comparison of historical emissions between the current Inventory and the previous
10 Inventory was also conducted to ensure that the changes in estimates were consistent with the changes
11 in activity data and emission factors.

12 **Recalculations Discussion**

13 New data on the activity of battery and plug-in hybrid electric vehicles was used to estimate electric
14 vehicle mileage (Browning, 2024). Past inventories estimated that electric vehicles had similar mileage
15 accumulation to conventionally fueled vehicles. The current inventory uses more recent data that shows
16 electric vehicles drive fewer miles than the average conventionally fueled vehicles. This update resulted
17 in total CO₂ emissions from electricity consumption by electric vehicles to decrease by 1.6 MMT (26
18 percent) in 2022 and 1.1 MMT in 2021 (22 percent), compared to the previous Inventory. CH₄ and N₂O
19 emissions are not impacted by this update.

20 Updated alternative fuel emissions factors based on the latest GREET model (GREET 2023) were also
21 included. As a result of these updates, CH₄ emissions from alternative fuel vehicles increased by an
22 annual average of .01 MMT CO₂ Eq. (27 to 30 percent) in the years 2020 through 2022 compared to the
23 previous Inventory. Alternative fuel vehicle N₂O emissions decreased by .01 MMT CO₂ Eq. (8 percent) in
24 2022 and changes in N₂O emissions in 2020 and 2021 were less than .01 MMT CO₂ Eq., relative to the
25 previous Inventory.

26 Output from the recently released MOVES5 model was used to update the vehicle fleet composition by
27 age and type and the estimated mileage and fuel use by vehicle type and model year. This change
28 affects the historical time series of emissions by vehicle type. A significant component of this change is
29 replacing projections based on MOVES3, with actual vehicle fleet data from MOVES5. MOVES5 also
30 includes more accurate projections based on the most recent data. This has increased the population
31 and activity (VMT) of light- and medium/heavy-duty trucks estimated across the time series. Due to this
32 update, N₂O emissions from gasoline powered highway vehicles increased by 0.03 MMT CO₂ Eq. (0.4
33 percent) in 2021 and 0.08 MMT CO₂ Eq. (1.5 percent) in 2022 compared to the previous Inventory. Total
34 N₂O emissions for diesel highway vehicles increased by less than 0.01 MMT CO₂ Eq. (0.1 percent) in
35 2021 and decreased by 0.1 MMT CO₂ Eq (2.9 percent) in 2022 compared to the previous Inventory.
36 Changes in CH₄ emissions for gasoline highway vehicles were small for 2021 and 2022, between -0.01
37 MMT CO₂ Eq. (-1.1 percent) in 2021 and less than 0.01 MMT CO₂ Eq. (0.4 percent) in 2022. Changes in
38 CH₄ emissions from diesel highway vehicles were small, decreasing 0.01 MMT CO₂ Eq. (9.4 percent) in
39 2021 and 0.02 (14.1 percent) in 2022.

40 Together, these updates resulted in an average annual increase of 0.4 MMT CO₂ Eq. (7.9 percent) in CH₄
41 emissions and an average annual increase 1.4 MMT CO₂ Eq. (4.8 percent) in N₂O emissions across the
42 time series compared to the previous *Inventory*.

1 **Planned Improvements**

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

- 4 • Improve estimates of electric vehicle activity and energy use. EIA publishes output from a model
5 that estimates electric vehicle energy consumption starting in 2018 for passenger vehicles.
6 Model results from EIA could be used to improve the estimates of electric vehicle activity and
7 energy use in the Inventory.
- 8 • Update emission factors for ships and non-recreational boats using residual fuel and distillate
9 fuel. Develop emission factors for locomotives using ultra-low sulfur diesel and emission
10 factors for aircraft using jet fuel. The Inventory currently uses IPCC default values for these
11 emission factors.
- 12 • Continue to explore potential improvements to estimates of domestic waterborne fuel
13 consumption for future Inventories. The Inventory estimates for residual and distillate fuel used
14 by ships and boats is based in part on data on bunker fuel use from the U.S. Department of
15 Commerce. Domestic fuel consumption is estimated by subtracting fuel sold for international
16 use from the total sold in the United States. Since 2015, all ships travelling within 200 nautical
17 miles of the U.S. coastlines must use distillate fuels, thereby overestimating the residual fuel
18 used by U.S. vessels and underestimating distillate fuel use in these ships. Additionally, the EIA
19 has stopped publishing the Fuel Oil and Kerosene Sales report, which reported data on distillate
20 marine fuel use in the U.S. and the territories. This affects the volume of fuel and emissions that
21 are allocated to the domestic ships and boats source, although top-down data is still available
22 from the Monthly Energy Review that will be used to estimate total domestic emission from
23 diesel fuel use. New data and methods are being explored to improve the diesel ships and boats
24 emissions estimates going forward.

25 **3.2 Carbon Emitted from Non-Energy Uses** 26 **of Fossil Fuels (Source Category 1A)**

27 In addition to being combusted for energy, fossil fuels are also consumed for non-energy uses (NEU) in
28 the United States. The fuels used for these purposes are diverse, including natural gas, hydrocarbon gas
29 liquids (HGL),⁵⁵ asphalt (a viscous liquid mixture of heavy crude oil distillates), petroleum coke
30 (manufactured from heavy oil), and coal (metallurgical) coke (manufactured from coking coal). The non-
31 energy applications of these fuels are equally diverse, including feedstocks for the manufacture of
32 plastics, rubber, synthetic fibers and other materials; reducing agents for the production of various
33 metals and inorganic products; and products such as lubricants, waxes, and asphalt (IPCC 2006).
34 Emissions from non-energy use of lubricants, paraffin waxes, bitumen/asphalt, and solvents are
35 reported in the Energy sector, as opposed to the Industrial Processes and Product Use (IPPU) sector, to

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.

1 reflect national circumstances in its choice of methodology and to increase transparency of this source
 2 category’s unique country-specific data sources and methodology (see Box). In addition, estimates of
 3 non-energy use emissions included here do not include emissions already reflected in the IPPU sector,
 4 e.g., fuels used as reducing agents. To avoid double counting, the “raw” non-energy fuel consumption
 5 data reported by EIA are reduced to account for these emissions already included under IPPU.

6 Carbon dioxide emissions arise from non-energy uses via several pathways. Emissions may occur
 7 during the manufacture of a product, as is the case in producing plastics or rubber from fuel-derived
 8 feedstocks. Additionally, emissions may occur during the product’s lifetime, such as during solvent use.
 9 Overall, throughout the time series and across all uses, about 64 percent of the total carbon consumed
 10 for non-energy purposes was stored in products (e.g., plastics), and not released to the atmosphere; the
 11 remaining 36 percent was emitted.

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

19 As shown in Table 3-23, fossil fuel emissions in 2023 from the non-energy uses of fossil fuels were 107.4
 20 MMT CO₂ Eq., which constituted approximately 2.2 percent of overall fossil fuel emissions. In 2023, the
 21 consumption of fuels for non-energy uses (after the adjustments described above) was 5,573.5 TBtu
 22 (see Table 3-24). A portion of the carbon in the 5,573.5 TBtu of fuels was stored (240.8 MMT CO₂ Eq.),
 23 while the remaining portion was emitted (107.4 MMT CO₂ Eq.). Non-energy use emissions increased by
 24 5.3 percent from 2022 to 2023, primarily due to increases in HGL production, natural gas to chemical
 25 plants, and naphtha. See Annex 2.3 for more details.

26 **Table 3-23: CO₂ Emissions from Non-Energy Use Fossil Fuel Consumption (MMT CO₂**
 27 **Eq. and Percent C)**

Year	1990	2005	2019	2020	2021	2022	2023
Potential Emissions	292.5	357.7	334.7	328.7	345.2	338.7	348.2
C Stored	193.4	232.7	228.2	230.8	233.4	236.7	240.8
Emissions as a % of Potential	34%	35%	32%	30%	32%	30%	31%
C Emitted	99.1	125.0	106.5	97.9	111.7	101.9	107.4

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

31 Methodology and Time-Series Consistency

32 As per discussion of methodology for estimating CO₂ emissions from fossil fuel combustion, NEU
 33 emissions are estimated in line with a Tier 2 method described by the *IPCC in the 2006 IPCC Guidelines*
 34 *for National Greenhouse Gas Inventories* (IPCC 2006) Chapter 2, Figure 2.1 decision tree and available
 35 data on energy use and country specific fuel carbon contents. The first step in estimating carbon stored
 36 in products was to determine the aggregate quantity of fossil fuels consumed for non-energy uses. The
 37 carbon content of these feedstock fuels is equivalent to potential emissions, or the product of

1 consumption and the fuel-specific carbon content values. Both the non-energy fuel consumption and
 2 carbon content data were supplied by the EIA (2024) (see Annex 2.1). Consumption values for industrial
 3 coking coal, petroleum coke, other oils, and natural gas in Table 3-24 and Table 3-25 have been adjusted
 4 to subtract non-energy uses that are included in the source categories of the Industrial Processes and
 5 Product Use chapter.⁵⁶ Consumption of natural gas, HGL, naphthas, other oils, and special naphtha
 6 were adjusted to subtract out net exports of these products that are not reflected in the raw data from
 7 EIA. Consumption values were also adjusted to subtract net exports of HGL components (e.g.,
 8 propylene, ethane).

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

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

27 **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

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
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
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	3.6	3.6	3.6	3.6
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	2.6	2.6	2.6	2.6
Total	4,337.1	5,227.5	5,278.9	5,215.5	5,464.8	5,414.6	5,573.5

1 NO (Not Occurring)

2 ^a Excludes natural gasoline.

3 ^b Formerly referred to as “pentanes plus.” This source has been adjusted and is reported separately from HGL to align with
4 historic data and revised EIA terminology.

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

6 **Table 3-25: 2023 Adjusted Non-Energy Use Fossil Fuel Consumption, Storage, and**
7 **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	100.6
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	12.0
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	5.9
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	3.6	NA	0.1	NA	+	0.1	0.2
Lubricants	1.0	20.2	+	0.1	+	+	0.1
Other Petroleum (Misc. Prod.)	2.6	20.0	0.1	0.1	+	+	0.2
Total	5,573.5		95.0		65.7	29.3	107.4

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

2 NA (Not Applicable)

3 NO (Not Occurring)

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

5 ^b Excludes natural gasoline.

6 ^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.

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

9 Lastly, emissions were estimated by subtracting the carbon stored from the potential emissions (see
10 Table 3-23). More detail on the methodology for calculating storage and emissions from each of these
11 sources is provided in Annex 2.3.

12 Where storage factors were calculated specifically for the United States, data were obtained on (1)
13 products such as asphalt, plastics, synthetic rubber, synthetic fibers, cleansers (soaps and detergents),
14 pesticides, food additives, antifreeze and deicers (glycols), and silicones; and (2) industrial releases
15 including energy recovery (waste gas from chemicals), Toxics Release Inventory (TRI) releases,
16 hazardous waste incineration, and volatile organic compound, solvent, and non-combustion CO
17 emissions. Data were taken from a variety of industry sources, government reports, and expert
18 communications. Sources include EPA reports and databases such as compilations of air emission
19 factors (EPA 2001), EPA’s Emissions Inventory System (EIS) to National Inventory Report (NIR) Mapping
20 file (EPA 2024a), *Toxics Release Inventory, 1998* (EPA 2000b), *Biennial Reporting System* (EPA 2000a,
21 2009), *Resource Conservation and Recovery Act Information System* (EPA 2013b, 2015, 2016b, 2018b,
22 2021, 2024b), pesticide sales and use estimates (EPA 1998, 1999, 2002, 2004, 2011, 2017), and the
23 Chemical Data Access Tool (EPA 2014b); the EIA Manufacturer’s Energy Consumption Survey (MECS)
24 (EIA 1994, 1997, 2001, 2005, 2010, 2013, 2017, 2021); the National Petrochemical & Refiners
25 Association (NPRA 2002); the U.S. Census Bureau (1999, 2004, 2009, 2014, 2021); Bank of Canada
26 (2012, 2013, 2014, 2016, 2017, 2018, 2019, 2020, 2021, 2022, 2023, 2024); Financial Planning
27 Association (2006); INEGI (2006); the United States International Trade Commission (2024); Gosselin,
28 Smith, and Hodge (1984); EPA’s *Municipal Solid Waste (MSW) Facts and Figures* (EPA 2013, 2014a,
29 2016a, 2018a, 2019); the U.S. Tire Manufacturers Association (USTMA 2012, 2013, 2014, 2016, 2018,
30 2020, 2022); the International Institute of Synthetic Rubber Products (IISRP 2000, 2003); the Fiber
31 Economics Bureau (FEB 2001, 2003, 2005, 2007, 2009, 2010, 2011, 2012, 2013); the Independent
32 Chemical Information Service (ICIS 2008, 2016); the EPA Chemical Data Access Tool (CDAT) (EPA
33 2014b); the American Chemistry Council (ACC 2003 through 2011, 2013, 2014, 2015, 2016, 2017, 2018,
34 2019, 2020, 2021, 2022, 2023, 2024a); the *Guide to the Business of Chemistry* (ACC 2024b); and the
35 Chemistry Industry Association of Canada (CIAC 2024). Specific data sources are listed in full detail in
36 Annex 2.3.

37 Methodological recalculations were applied to the entire time series to ensure time-series consistency
38 from 1990 through 2022 as discussed below.

39 **Box 3-5: Reporting of Lubricants, Waxes, and Asphalt and Road Oil Product Use in** 40 **Energy Sector**

41 IPCC (2006) provides methodological guidance to estimate emissions from the first use of fossil fuels as
42 a product for primary purposes other than combustion for energy purposes (including lubricants,
43 paraffin waxes, bitumen / asphalt, and solvents) under the IPPU sector. In this Inventory, carbon storage
44 and carbon emissions from product use of lubricants, waxes, and asphalt and road oil are reported

1 under the Energy sector in the Carbon Emitted from Non-Energy Uses of Fossil Fuels source category
2 (Source Category 1A5).

3 The emissions are reported in the Energy sector, as opposed to the IPPU sector, to reflect national
4 circumstances in its choice of methodology and to increase transparency of this source category's
5 unique country-specific data sources and methodology. Although emissions from these non-energy
6 uses are reported in the Energy chapter the methodologies used to determine emissions are compatible
7 with the 2006 IPCC Guidelines. The country-specific methodology used for the Carbon Emitted from
8 Non-Energy Uses of Fossil Fuels source category is based on a carbon balance (i.e., carbon inputs-
9 outputs) calculation of the aggregate amount of fossil fuels used for non-energy uses, including inputs
10 of lubricants, waxes, asphalt and road oil (see Table 3 22).

11 For those inputs, U.S. country-specific data on carbon stocks and flows are used to develop carbon
12 storage factors, which are calculated as the ratio of the carbon stored by the fossil fuel non-energy
13 products to the total carbon content of the fuel consumed, taking into account losses in the production
14 process and during product use. The country-specific methodology to reflect national circumstances
15 starts with the aggregate amount of fossil fuels used for non-energy uses and applies a carbon balance
16 calculation, breaking out the carbon emissions from non-energy use of lubricants, waxes, and asphalt
17 and road oil. The emissions are reported under the Energy chapter to improve transparency, report a
18 more complete carbon balance and to avoid double counting. Due to U.S. national circumstances,
19 reporting these carbon emissions separately under IPPU would involve making artificial adjustments to
20 allocate both the carbon inputs and carbon outputs of the non-energy use carbon balance. For example,
21 only the emissions from the first use of lubricants and waxes are to be reported under the IPPU sector,
22 emissions from use of lubricants in 2-stroke engines and emissions from secondary use of lubricants
23 and waxes in waste incineration with energy recovery are to be reported under the Energy sector.
24 Reporting these non-energy use emissions from only first use of lubricants and waxes under IPPU would
25 involve making artificial adjustments to the non-energy use carbon balance and could potentially result
26 in double counting of emissions. These artificial adjustments would also be required for asphalt and
27 road oil and solvents (which are captured as part of petrochemical feedstock emissions) and could also
28 potentially result in double counting of emissions. To avoid presenting an incomplete carbon balance
29 and a less transparent approach for the Carbon Emitted from Non-Energy Uses of Fossil Fuels source
30 category calculation, the entire calculation of carbon storage and carbon emissions is therefore
31 conducted in the Non-Energy Uses of Fossil Fuels category calculation methodology, and both the
32 carbon storage and carbon emissions for lubricants, waxes, and asphalt and road oil are reported under
33 the Energy sector.

34 However, emissions from non-energy uses of fossil fuels as feedstocks or reducing agents (e.g.,
35 petrochemical production, aluminum production, titanium dioxide, and zinc production) are reported in
36 the IPPU chapter, unless otherwise noted due to specific national circumstances.
37

38 Uncertainty

39 An uncertainty analysis was conducted to quantify the uncertainty surrounding the estimates of
40 emissions and storage factors from non-energy uses. This analysis, performed using @RISK software
41 and the IPCC-recommended Approach 2 methodology (Monte Carlo stochastic simulation technique),
42 provides for the specification of probability density functions for key variables within a computational
43 structure that mirrors the calculation of the inventory estimate. The results presented below provide the

1 95 percent confidence interval, the range of values within which emissions are likely to fall, for this
2 source category.

3 As noted above, the non-energy use analysis is based on U.S.-specific storage factors for (1) feedstock
4 materials (natural gas, HGL, natural gasoline, naphthas, other oils, still gas, special naphthas, and other
5 industrial coal), (2) asphalt, (3) lubricants, and (4) waxes. For the remaining fuel types (the “other”
6 category in Table 3-24 and Table 3-25) the storage factors were taken directly from IPCC (2006), where
7 available, and otherwise assumptions were made based on the potential fate of carbon in the respective
8 NEU products. To characterize uncertainty, five separate analyses were conducted, corresponding to
9 each of the five categories. In all cases, statistical analyses or expert judgments of uncertainty were not
10 available directly from the information sources for all the activity variables; thus, uncertainty estimates
11 were determined using assumptions based on source category knowledge.

12 The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-26
13 (emissions) and Table 3-27 (storage factors). Carbon emitted from non-energy uses of fossil fuels in
14 2023 was estimated to be between 68.8 and 172.3 MMT CO₂ Eq. at a 95 percent confidence level. This
15 indicates a range of 36 percent below to 60 percent above the 2023 emission estimate of 107.4 MMT
16 CO₂ Eq. The uncertainty in the emission estimates is a function of uncertainty in both the quantity of fuel
17 used for non-energy purposes and the storage factor.

18 **Table 3-26: Approach 2 Quantitative Uncertainty Estimates for CO₂ Emissions from**
19 **Non-Energy Uses of Fossil Fuels (MMT CO₂ 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	88.4	52.1	155.4	-41%	+76%
Asphalt	CO ₂	0.3	0.1	0.7	-59%	+120%
Lubricants	CO ₂	12.4	10.3	14.4	-17%	+16%
Waxes	CO ₂	0.3	0.2	0.6	-26%	+100%
Other	CO ₂	5.9	1.2	6.8	-79%	+15%
Total	CO₂	107.4	68.8	172.3	-36%	+60%

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

22 **Table 3-27: Approach 2 Quantitative Uncertainty Estimates for Storage Factors of Non-**
23 **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%	-21%	+12%
Asphalt	CO ₂	99.6%	99%	100%	0.5%	0.3%
Lubricants	CO ₂	9.2%	4%	18%	-58%	+93%
Waxes	CO ₂	57.8%	48%	68%	-18%	+17%
Other	CO ₂	12.6%	8%	81%	-35%	+549%

1 ^a Range of emission estimates predicted by Monte Carlo stochastic simulation for a 95 percent confidence interval, as a
2 percentage of the inventory value (also expressed in percent terms).

3 As shown in Table 3-27, waxes and asphalt contribute least to overall storage factor uncertainty on a
4 percentage basis. Although the feedstocks category—the largest use category in terms of total carbon
5 flows—also appears to have relatively tight confidence limits, this is to some extent an artifact of the
6 way the uncertainty analysis was structured. As discussed in Annex 2.3, the storage factor for
7 feedstocks is based on an analysis of six fates that result in long-term storage (e.g., plastics production),
8 and 11 that result in emissions (e.g., volatile organic compound emissions). Rather than modeling the
9 total uncertainty around all of these fate processes, the current analysis addresses only the storage
10 fates, and assumes that all carbon that is not stored is emitted. As the production statistics that drive
11 the storage values are relatively well-characterized, this approach yields a result that is probably biased
12 toward understating uncertainty.

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

16 QA/QC and Verification

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

27 For petrochemical import and export data, special attention was paid to NAICS numbers and titles to
28 verify that none had changed or been removed. Import and export totals were compared with 2022
29 totals as well as their trends across the time series.

30 It is important to ensure no double counting of emissions between fuel combustion, non-energy use of
31 fuels and industrial process emissions. For petrochemical feedstock production, our review of the
32 categories suggests this is not a significant issue since the non-energy use industrial release data
33 includes different categories of sources and sectors than those included in the Industrial Processes and
34 Product Use (IPPU) emissions category for petrochemicals. Further data integration is not available at
35 this time because feedstock data from the EIA used to estimate non-energy uses of fuels are aggregated
36 by fuel type, rather than disaggregated by both fuel type and particular industries. Also, GHGRP-reported
37 data on quantities of fuel consumed as feedstocks by petrochemical producers are unable to be used
38 due to the data failing GHGRP CBI aggregation criteria. This country-specific approach taken is better
39 able to reflect the national situation because it accounts for secondary product imports and exports
40 that are not included directly in the national energy statistics. Furthermore, it is compatible with the
41 *2006 IPCC Guidelines* as discussed in Box 3-4 above, but also as the NEU emissions are here represent
42 different emissions from those covered in the IPPU petrochemical production category.

1 Recalculations Discussion

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

- 4 • ACC (2023b) updated adipic acid, and acetic acid production in 2022, which resulted in a slight
5 decrease in emissions relative to the previous *Inventory*.
- 6 • U.S. International Trade Commission (2024) updated historical import and export data from
7 2020 to 2022 for cleansers and antifreeze, resulting in slight changes from the previous
8 *Inventory*.
- 9 • EIA (2024) updated historical fuel consumption data for HGL, industrial coking coal, and
10 lubricants, resulting in a decrease in emissions for the period 2019 through 2022.
- 11 • EPA (2024b) published new data on the quantity of hazardous waste incinerated in 2021 and
12 2023, resulting in a slight decrease in emissions for the period 2020 through 2022.
- 13 • EPA updated the methodology for estimating the consumption of other petroleum liquids by
14 U.S. Pacific Islands and Wake Island for years 2020 through 2022 to fill data gaps in the
15 publication. These years are now proxied to 2019, resulting in a slight increase in emissions
16 relative to the previous *Inventory*.

17 Overall, these changes resulted in an average annual decrease of less than 0.05 MMT CO₂ Eq. (less than
18 0.05 percent) in carbon emissions from non-energy uses of fossil fuels for the period 1990 through 2022,
19 relative to the previous *Inventory*. This change was driven by slight increases in emissions for the period
20 2019 through 2021, and a decrease in emissions in 2022.

21 Planned Improvements

22 There are several future improvements planned:

- 23 • More accurate accounting of carbon in petrochemical feedstocks. EPA has worked with EIA to
24 determine the cause of input/output discrepancies in the carbon mass balance contained
25 within the NEU model. In the future, two strategies to reduce or eliminate this discrepancy will
26 continue to be pursued as part of quality control procedures. First, accounting of carbon in
27 imports and exports will be improved. The import/export adjustment methodology will be
28 examined to ensure that net exports of intermediaries such as ethylene and propylene are fully
29 accounted for. Second, the use of top-down carbon input calculation in estimating emissions
30 will be reconsidered. Alternative approaches that rely more substantially on the bottom-up
31 carbon output calculation will be considered instead.
- 32 • Improving the uncertainty analysis. Most of the input parameter distributions are based on
33 professional judgment rather than rigorous statistical characterizations of uncertainty.
- 34 • Better characterizing flows of fossil carbon. Additional fates may be researched, including the
35 fossil carbon load in organic chemical wastewaters, plasticizers, adhesives, films, paints, and
36 coatings. There is also a need to further clarify the treatment of fuel additives and backflows
37 (especially methyl tert-butyl ether, MTBE).

- 1 • Reviewing the trends in fossil fuel consumption for non-energy uses. Annual consumption for
2 several fuel types is highly variable across the time series, including industrial coking coal and
3 other petroleum. A better understanding of these trends will be pursued to identify any
4 mischaracterized or misreported fuel consumption for non-energy uses.
- 5 • Updating the average carbon content of solvents was researched, since the entire time series
6 depends on one year's worth of solvent composition data. The data on carbon emissions from
7 solvents that were readily available do not provide composition data for all categories of solvent
8 emissions and also have conflicting definitions for volatile organic compounds, the source of
9 emissive carbon in solvents. Additional sources of solvents data will be investigated in order to
10 update the carbon content assumptions.
- 11 • Updating the average carbon content of cleansers (soaps and detergents) was researched;
12 although production and consumption data for cleansers are published every 5 years by the
13 Census Bureau, the composition (C content) of cleansers has not been recently updated.
14 Recently available composition data sources may facilitate updating the average carbon
15 content for this category.
- 16 • Revising the methodology for consumption, production, and carbon content of plastics was
17 researched; because of recent changes to the type of data publicly available for plastics, the
18 NEU model for plastics applies data obtained from personal communications. Potential
19 revisions to the plastics methodology to account for the recent changes in published data will
20 be investigated.
- 21 • Although U.S.-specific storage factors have been developed for feedstocks, asphalt, lubricants,
22 and waxes, default values from IPCC are still used for two of the non-energy fuel types
23 (industrial coking coal, distillate oil), and broad assumptions are being used for miscellaneous
24 products and other petroleum. Over the long term, there are plans to improve these storage
25 factors by analyzing carbon fate similar to those described in Annex 2.3 or deferring to more
26 updated default storage factors from IPCC where available.
- 27 • Reviewing the storage of carbon black across various sectors in the *Inventory*; in particular, the
28 carbon black abraded and stored in tires.
- 29 • Assess the current method and/or identify new data sources (e.g., EIA) for estimating emissions
30 from ammonia/fertilizer use of natural gas.
- 31 Investigate EIA NEU and MECS data to update, as needed, adjustments made for ammonia production
32 and “natural gas to chemical plants, other uses” and “natural gas to other” non-energy uses, including
33 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 CO₂. According to the *2006 IPCC Guidelines*, when the CO₂ emitted is of fossil origin, it is counted as a net anthropogenic emission of CO₂ to the atmosphere. Thus, the emissions from waste 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 26.326.3 million metric tons of MSW were combusted in 2023 (EPA 2022). Carbon dioxide emissions from combustion of waste decreased 4.2 percent since 1990, to an estimated 12.4 MMT CO₂ (12,357 kt) in 2023. Emissions across the time series are shown in Table 3-28 and Table 3-29. For the Public Review, 2023 waste combustion values were not available and were proxied based on 2022 values. Results will be updated for the Final Review.

Waste combustion is also a source of CH₄ and N₂O emissions (De Soete 1993; IPCC 2006). Methane emissions from the combustion of waste were estimated to be less than 0.5MMT CO₂ Eq. (less than 0.05 kt CH₄) in 2023 and have remained steady since 1990. Nitrous oxide emissions from the combustion of waste were estimated to be 0.3 MMT CO₂ Eq. (1.3 kt N₂O) in 2023 and have decreased by 18 percent since 1990. This decrease is driven by the decrease in total MSW combusted.

1 **Table 3-28: CO₂, CH₄, and N₂O Emissions from the Combustion of Waste (MMT CO₂ Eq.)**

Gas	1990	2005	2019	2020	2021	2022	2023
CO ₂	12.9	13.3	12.9	12.9	12.5	12.4	12.4
CH ₄	+	+	+	+	+	+	+
N ₂ O	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	12.7	12.7

2 + Does not exceed 0.05 MMT CO₂ Eq.

3 Note: Totals may not sum due to independent rounding. Waste combustion data were not available and were proxied based on
4 2022 values. Results will be updated for the Final Review.

5 **Table 3-29: CO₂, CH₄, and N₂O 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	12,357	12,357
CH ₄	+	+	+	+	+	+	+
N ₂ O	2	1	1	1	1	1	1

6 + Does not exceed 0.05 kt. Waste combustion data were not available and were proxied based on 2022 values. Results will be
7 updated for the Final Review.

8 Methodology and Time-Series Consistency

9 Municipal Solid Waste Combustion

10 A Tier 2 approach is used to determine both CO₂ and non-CO₂ emissions from the combustion of waste,
11 the method uses tonnage of waste combusted and an estimated country specific emissions factor.

12 Emission estimates from the combustion of tires are discussed separately. Data for total waste
13 combusted was derived from *BioCycle* (van Haaren et al. 2010), EPA Facts and Figures Report, Energy
14 Recovery Council (ERC), EPA's Greenhouse Gas Reporting Program (GHGRP), and the U.S. Energy
15 Information Administration (EIA). Multiple sources were used to ensure a complete, quality dataset, as
16 each source encompasses a different timeframe.

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

- 18 • 1990-2006: MSW combustion tonnages are from Biocycle combustion data. Tire combustion
19 data from the U.S. Tire Manufacturers Association (USTMA) are removed to arrive at MSW
20 combusted without tires.
- 21 • 2006-2010: MSW combustion tonnages are an average of Biocycle (with USTMA tire data
22 tonnage removed), U.S. EPA Facts and Figures, EIA, and Energy Recovery Council data (with
23 USTMA tire data tonnage removed).
- 24 • 2011-2022: MSW combustion tonnages are from EPA's GHGRP data.

25 Table 3-30 provides the estimated tons of MSW combusted including and excluding tires. 2023 waste
26 combustion data were proxied based on 2022 values. Results will be updated for the Final Review.

1 **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	26,338,130
Waste Combusted (including tires)	33,766,239	28,631,054	29,821,141	29,106,686	29,261,446	27,732,130	27,732,130

2 Sources: BioCycle, EPA Facts and Figures, ERC, GHGRP, EIA, USTMA. Waste combustion data were not available and were
 3 proxied based on 2022 values. Results will be updated for the Final Review.

4 **CO₂ Emissions from MSW Excluding Scrap Tires**

5 Fossil CO₂ emission factors were calculated from EPA’s GHGRP data for non-biogenic sources. Using
 6 GHGRP-reported emissions for CH₄ and N₂O and assumed emission factors, the tonnage of waste
 7 combusted, excluding tires, was derived. Methane and N₂O emissions and assumed emission factors
 8 were used to estimate the amount of MSW combusted in terms of energy content. The energy content of
 9 MSW combusted was then converted into tonnage based on assumed MSW heating value. Two
 10 estimates were generated (one for CH₄ and one for N₂O) and the two were averaged together. Dividing
 11 fossil CO₂ emissions from GHGRP FLIGHT data for MSW combustors by this estimated tonnage yielded
 12 an annual CO₂ emission factor. As this data was only available following 2011, all years prior use an
 13 average of the emission factors from 2011 through 2015. See Annex 3.7 for more detail on how MSW
 14 carbon factors were calculated.

15 Finally, CO₂ emissions were calculated by multiplying the annual tonnage estimates, excluding tires, by
 16 the calculated emissions factor. Calculated fossil CO₂ emission factors are shown in Table 3-31. For the
 17 Public Review, 2023 waste combustion values were not available and were proxied based on 2022
 18 values. Results will be updated for the Final Review.

19 **Table 3-31: Calculated Fossil CO₂ Content per Ton Waste Combusted (kg CO₂/Short
 20 Ton Combusted)**

Year	1990	2005	2019	2020	2021	2022	2023
CO ₂ Emission Factors	366	366	363	377	365	382	382

21 Waste combustion data were not available and were proxied based on 2022 values. Results will be updated for the Final Review.

22 **CO₂ Emissions from Scrap Tires**

23 Scrap tires contain several types of synthetic rubber, carbon black, and synthetic fibers. Each type of
 24 synthetic rubber has a discrete carbon content, and carbon black is 100 percent C. For synthetic rubber
 25 and carbon black in scrap tires, information on average weight, disposal percentage, and total tires
 26 incinerated for energy was obtained biannually from U.S. Scrap Tire Management Summary for 2005
 27 through 2022 data (USTMA 2022). Information about scrap tire composition was taken from the Rubber
 28 Manufacturers’ Association internet site (USTMA 2012a). Emissions of CO₂ were calculated based on
 29 the amount of scrap tires used for fuel and the synthetic rubber and carbon black content of scrap tires.
 30 The mass of combusted material is multiplied by its carbon content to calculate the total amount of
 31 carbon stored. 2023 values are proxied from 2021 data. More detail on the methodology for calculating
 32 emissions from each of these waste combustion sources is provided in Annex 3.7. Table 3-32 provides
 33 CO₂ emissions from combustion of waste tires.

1 **Table 3-32: CO₂ Emissions from Combustion of Tires (MMT CO₂ Eq.)**

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

2 Waste combustion data were not available and were proxied based on 2022 values. Results will be updated for the Final Review.
 3 Note: Totals may not sum due to independent rounding.

4 **Non-CO₂ Emissions**

5 Combustion of waste also results in emissions of CH₄ and N₂O. These emissions were calculated by
 6 multiplying the total estimated mass of waste combusted, including tires, by the respective emission
 7 factors. The emission factors for CH₄ and N₂O emissions per quantity of MSW combusted are default
 8 emission factors for the default continuously-fed stoker unit MSW combustion technology type and
 9 were taken from IPCC (2006).

10 **Uncertainty**

11 An Approach 2 Monte Carlo analysis was performed to determine the level of uncertainty surrounding
 12 the estimates of CO₂ emissions and N₂O emissions from the incineration of waste (given the very low
 13 emissions for CH₄, no uncertainty estimate was derived). IPCC Approach 2 analysis allows the
 14 specification of probability density functions for key variables within a computational structure that
 15 mirrors the calculation of the *Inventory* estimate. Statistical analyses or expert judgments of uncertainty
 16 were not available directly from the information sources for most variables; thus, uncertainty estimates
 17 for these variables were determined using assumptions based on source category knowledge and the
 18 known uncertainty estimates for the waste generation variables.

19 The uncertainties in the waste incineration emission estimates arise from both the assumptions applied
 20 to the data and from the quality of the data. Key factors include reported CO₂ emissions; N₂O and CH₄
 21 emissions factors, and tire synthetic rubber and black carbon contents. The highest levels of uncertainty
 22 surround the reported emissions from GHGRP; the lowest levels of uncertainty surround variables that
 23 were determined by quantitative measurements (e.g., combustion efficiency, carbon content of carbon
 24 black).

25 The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-23. Waste
 26 incineration CO₂ emissions in 2023 were estimated to be between 10.3 and 14.3 MMT CO₂ Eq. at a 95
 27 percent confidence level. This indicates a range of 17 percent below to 16 percent above the 2023
 28 emission estimate of 12.4 MMT CO₂ Eq. Waste incineration CH₄ emissions in 2023 were estimated to be
 29 between less than 0.000005 and less than 0.0005 MMT CO₂ Eq. at a 95 percent confident level. This
 30 indicates a range of 98 percent below to 100 percent above the 2023 emission estimate of less than
 31 0.0005 MMT CO₂ Eq. Also at a 95 percent confidence level, waste incineration N₂O emissions in 2023
 32 were estimated to be between 0.2 and 0.9 MMT CO₂ Eq. This indicates a range of 53 percent below to
 33 162 percent above the 2023 emission estimate of 0.3 MMT CO₂ Eq.

1 **Table 3-33: Approach 2 Quantitative Uncertainty Estimates for CO₂ and N₂O from the**
 2 **Incineration of Waste (MMT CO₂ 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	14.3	-17%	16%
Incineration of Waste	CH ₄	+	+	+	-98%	100%
Incineration of Waste	N ₂ O	0.3	0.2	0.9	-53%	162%

3 ⁺ Does not exceed 0.05 MMT CO₂ Eq.

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

5 QA/QC and Verification

6 In order to ensure the quality of the emission estimates from waste combustion, general (IPCC Tier 1)
 7 and category-specific (Tier 2) Quality Assurance/Quality Control (QA/QC) procedures were
 8 implemented consistent with the U.S. Inventory QA/QC plan outlined in Annex 8. The Tier 2 procedures
 9 that were implemented involved checks specifically focusing on the activity data and specifically
 10 focused on the emission factor and activity data sources and methodology used for estimating
 11 emissions from combustion of waste. Trends across the time series were analyzed to determine
 12 whether any corrective actions were needed. Corrective actions were taken to rectify minor errors in the
 13 use of activity data.

14 Recalculations Discussion

15 No recalculations were performed for the current *Inventory*.

16 Planned Improvements

17 No planned improvements for waste combustion were identified.

18 3.4 Coal Mining (Source Category 1B1a)

19 Three types of coal mining-related activities release CH₄ and CO₂ to the atmosphere: underground
 20 mining, surface mining, and post-mining (i.e., coal-handling) activities. While surface coal mines
 21 account for the majority of U.S. coal production, underground coal mines contribute the largest share of
 22 fugitive CH₄ emissions (see Table 3-35 and Table 3-36) due to the higher CH₄ content of coal in the
 23 deeper underground coal seams. In 2023, 190 underground coal mines and 362 surface mines were
 24 operating in the United States (EIA 2024). In recent years, the total number of active coal mines in the
 25 United States has declined. In 2023, the United States was the fourth largest coal producer in the world,
 26 after China, India, and Indonesia (IEA 2023).

1 **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

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

3 Fugitive CH₄ Emissions

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

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

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

18 Total CH₄ emissions in 2023 were estimated to be 1,621 kt (45.4 MMT CO₂ Eq.), a decline of
 19 approximately 58 percent since 1990 (see Table 3-35 and Table 3-36). In 2023, underground mines
 20 accounted for approximately 74 percent of total emissions, surface mines accounted for 13 percent,
 21 and post-mining activities accounted for 13 percent. In 2023, total CH₄ emissions from coal mining
 22 increased by approximately 4 percent relative to the previous year. Total coal production in 2023
 23 decreased by 3 percent compared to 2022. This resulted in an decrease of 1 percent in CH₄ emissions
 24 from surface mining and post-mining activities in 2023. However, surface mining and post-mining
 25 activities have a lower impact on total CH₄ compared to underground mining (74 percent of total
 26 emissions in 2023). The number of operating underground mines increased in 2023 and the amount of
 27 CH₄ recovered and used in 2023 decreased by 6 percent compared to 2022. In 2023, the amount of CH₄
 28 from underground mining activities increased by 6 percent compared to 2022.

1 **Table 3-35: CH₄ Emissions from Coal Mining (MMT CO₂ 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

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

3 **Table 3-36: CH₄ 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	1,192
Liberated	3,237	2,388	2,022	1,917	1,868	2,003	2,122
Recovered & Used	(269)	(719)	(646)	(660)	(692)	(880)	(930)
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	1,621

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

5 Methodology and Time-Series Consistency

6 EPA uses an IPCC Tier 3 method for estimating CH₄ emissions from underground coal mining and an
 7 IPCC Tier 2 method for estimating CH₄ emissions from surface mining and post-mining activities (for
 8 coal production from both underground mines and surface mines) in accordance with methodological
 9 decisions trees in IPCC guidelines (Volume 2, Chapter 4, Figure 4.1.1 and 4.1.2) and available data
 10 (IPCC 2006). The methodology for estimating CH₄ emissions from coal mining consists of two steps:

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

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

20 Underground mines generate CH₄ from ventilation systems and degasification systems. Some mines
 21 recover and use the liberated CH₄, thereby reducing emissions to the atmosphere. Total CH₄ emitted
 22 from underground mines equals the CH₄ liberated from ventilation systems, plus the CH₄ liberated from
 23 degasification systems, minus the CH₄ recovered and used.

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

2 To estimate CH₄ liberated from ventilation systems, EPA uses data collected through its Greenhouse
3 Gas Reporting Program (GHGRP)⁵⁷ (Subpart FF, “Underground Coal Mines”), data provided by the U.S.
4 Mine Safety and Health Administration (MSHA) (MSHA 2024), and occasionally data collected from
5 other sources on a site-specific level (e.g., state gas production databases). Since 2011, the nation’s
6 “gassiest” underground coal mines—those that liberate more than 36,500,000 actual cubic feet of CH₄
7 per year (about 17,525 MT CO₂ Eq.)—have been required to report to EPA’s GHGRP (EPA 2024).⁵⁸ Mines
8 that report to EPA’s GHGRP must report quarterly measurements of CH₄ emissions from ventilation
9 systems; they have the option of recording and reporting their own measurements, or using the
10 measurements taken by MSHA as part of that agency’s quarterly safety inspections of all mines in the
11 United States with detectable CH₄ concentrations.⁵⁹

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

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

23 Particularly gassy underground mines also use degasification systems (e.g., wells or boreholes) to
24 remove CH₄ before, during, or after mining. This CH₄ can then be collected for use or vented to the
25 atmosphere. Nineteen mines used degasification systems in 2023 and all of these mines reported the
26 CH₄ removed through these systems to EPA’s GHGRP under Subpart FF (EPA 2024). Based on the weekly
27 measurements reported to EPA’s GHGRP, degasification data summaries for each mine are added to
28 estimate the CH₄ liberated from degasification systems. Eleven of the 19 mines with degasification
29 systems had operational CH₄ recovery and use projects, including two mines with two recovery and use
30 projects each (see step 1.3 below).⁶⁰

31 Degasification data reported to EPA’s GHGRP by underground coal mines is the primary source of data
32 used to develop estimates of CH₄ liberated from degasification systems. Data reported to EPA’s GHGRP
33 were used exclusively to estimate CH₄ liberated from degasification systems at 13 of the 19 mines that
34 used degasification systems in 2023. Data from state gas well production databases were used to

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

⁶⁰ Several of the mines venting CH₄ from degasification systems use a small portion of the gas to fuel gob well blowers in remote locations where electricity is not available. However, this CH₄ use is not considered to be a formal recovery and use project.

1 supplement GHGRP degasification data for the remaining 6 mines (DMME 2024; ERG 2024; GSA 2024;
2 WVGES 2024).

3 For pre-mining wells, cumulative degasification volumes that occur prior to the well being mined
4 through are attributed to the mine in the inventory year in which the well is mined through.⁶¹ EPA's
5 GHGRP does not require gas production from virgin coal seams (coalbed methane) to be reported by
6 coal mines under Subpart FF.⁶² Most pre-mining wells drilled from the surface are considered coalbed
7 methane wells prior to mine-through and associated CH₄ emissions are reported under another subpart
8 of the GHGRP (Subpart W, "Petroleum and Natural Gas Systems"). As a result, GHGRP data must be
9 supplemented to estimate cumulative degasification volumes that occurred prior to well mine-through.
10 There were five mines with degasification systems that include pre-mining wells that were mined
11 through in 2023. For all of these mines, GHGRP data were supplemented with historical data from state
12 gas well production databases (ERG 2024; GSA 2024), as well as with mine-specific information
13 regarding the locations and dates on which the pre-mining wells were mined through (JWR 2010; El Paso
14 2009; ERG 2024).

15 ***Step 1.3: Estimate CH₄ Recovered from Ventilation and Degasification Systems, and*** 16 ***Utilized or Destroyed (Emissions Avoided)***

17 Eleven mines had a total of 13 CH₄ recovery and use projects in place in 2023, including two mines that
18 each have two recovery and use projects. Twelve of these projects involved degasification systems with
19 one mine having a ventilation air methane abatement project (VAM). Ten of these mines sold the
20 recovered CH₄ to a pipeline, including one that also used CH₄ to fuel a thermal coal dryer. One mine
21 destroyed the recovered CH₄ (VAM) using regenerative thermal oxidation (RTO) without energy recovery
22 and using enclosed flares.

23 The CH₄ recovered and used (or destroyed) at the 11 mines described above are estimated using the
24 following methods:

- 25 • EPA's GHGRP data was exclusively used to estimate the CH₄ recovered and used from five of the
26 11 mines that deployed degasification systems in 2023. Based on quarterly measurements, the
27 GHGRP degasification destruction data summaries for each mine are added together to
28 estimate the CH₄ recovered and used from degasification systems.
- 29 • State sales data were used to supplement GHGRP data to estimate CH₄ recovered and used
30 from five mines that deployed degasification systems in 2023 (DMME 2024, ERG 2024, GSA
31 2024, and WVGES 2024). Supplemental information is used for these mines because estimating
32 CH₄ recovery and use from pre-mining wells requires additional data not reported under Subpart
33 FF of EPA's GHGRP (see discussion in step 1.2 above) to account for the emissions avoided prior
34 to the well being mined through. The supplemental data is obtained from state gas production
35 databases as well as mine-specific information on the location and timing of mined-through
36 pre-mining wells.
- 37 • For the single mine that employed VAM for CH₄ recovery and use, the estimates of CH₄
38 recovered and used were obtained from the mine's offset verification statement (OVS)
39 submitted to the California Air Resources Board (CARB) (McElroy OVS 2023). This mine also

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

1 reported CH₄ reductions from flaring. GHGRP data were used to estimate CH₄ recovered and
 2 flared in 2023 (EPA 2024).

3 **Step 2: Estimate CH₄ Emitted from Surface Mines and Post-Mining** 4 **Activities**

5 Mine-specific data are not available for estimating CH₄ emissions from surface coal mines or for post-
 6 mining activities. For surface mines, basin-specific coal production obtained from the Energy
 7 Information Administration’s *Annual Coal Report* (EIA 2024) is multiplied by basin-specific CH₄ contents
 8 (EPA 1996, 2005) and a 150 percent emission factor (to account for CH₄ from over- and under-burden) to
 9 estimate CH₄ emissions (King 1994; Saghafi 2013). For post-mining activities, basin-specific coal
 10 production is multiplied by basin-specific CH₄ contents and a mid-range 32.5 percent emission factor
 11 for CH₄ desorption during coal transportation and storage (Creedy 1993). Basin-specific in situ gas
 12 content data were compiled from AAPG (1984) and USBM (1986).

13 **Fugitive CO₂ Emissions**

14 Methane and CO₂ are naturally occurring in coal seams and are collectively referred to as coal seam
 15 gas. These gases remain trapped in the coal seam until coal is mined (i.e., coal seam is exposed and
 16 fractured during mining operations). Fugitive CO₂ emissions occur during underground coal mining,
 17 surface coal mining, and post-mining activities. Methods and data to estimate fugitive CO₂ emissions
 18 from underground and surface coal mining are presented in the sections below. Fugitive CO₂ emissions
 19 from post-mining activities were not estimated due to the lack of an IPCC method and unavailability of
 20 data.

21 Total fugitive CO₂ emissions in 2023 were estimated to be 2,408 kt (2.4 MMT CO₂ Eq.), a decline of
 22 approximately 48 percent since 1990. In 2023, underground mines accounted for approximately 89
 23 percent of total fugitive CO₂ emissions. In 2023, total fugitive CO₂ emissions from coal mining
 24 decreased by approximately 3 percent relative to the previous year. This decrease was due to a decrease
 25 in annual coal production.

26 **Table 3-37: CO₂ Emissions from Coal Mining (MMT CO₂ 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

27 + Does not exceed 0.05 MMT CO₂ Eq.

28 NO (Not Occurring)

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

30 **Table 3-38: CO₂ 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	2,143

Activity	1990	2005	2019	2020	2021	2022	2023
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	24
Surface Mining	443	560	322	249	262	273	264
Total	4,606	4,169	2,992	2,197	2,455	2,474	2,408

1 NO (Not Occurring)

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

3 Methodology and Time-Series Consistency

4 EPA uses an IPCC Tier 1 method for estimating fugitive CO₂ emissions from underground coal mining
5 and surface mining in accordance with methodological decisions trees in IPCC guidelines (Volume 2,
6 Chapter 4, Figure 4.1.1a) and available data (IPCC 2019). IPCC methods and data to estimate fugitive
7 CO₂ emissions from post-mining activities (for both underground and surface coal mining) are currently
8 not available.

9 Step 1: Underground Mining

10 EPA used the following overarching IPCC equation to estimate fugitive CO₂ emissions from underground
11 coal mines (IPCC 2019):

12 Equation 3-1: Estimating Fugitive CO₂ Emissions from Underground Mines

$$\begin{aligned}
 & \text{Total CO}_2 \text{ from Underground Mines} \\
 & = \text{CO}_2 \text{ from underground mining} - \text{Amount of CO}_2 \text{ in gas recovered} \\
 & + \text{CO}_2 \text{ from methane flaring}
 \end{aligned}$$

16 Step 1.1: Estimate Fugitive CO₂ Emissions from Underground Mining

17 EPA estimated fugitive CO₂ emissions from underground mining using the IPCC Tier 1 emission factor
18 (5.9 m³/metric ton) and annual coal production from underground mines (EIA 2024). The underground
19 mining default emission factor accounts for all the fugitive CO₂ likely to be emitted from underground
20 coal mining. Therefore, the amount of CO₂ from coal seam gas recovered and utilized for energy is
21 subtracted from underground mining estimates in Step 2, below. Under IPCC methods, the CO₂
22 emissions from gas recovered and utilized for energy use (e.g., injected into a natural gas pipeline) are
23 reported under other sectors of the *Inventory* (e.g., stationary combustion of fossil fuel or oil and natural
24 gas systems) and not under the coal mining sector.

25 Step 1.2: Estimate Amount of CO₂ In Coal Seam Gas Recovered for Energy Purposes

26 EPA estimated fugitive CO₂ emissions from coal seam gas recovered and utilized for energy purposes by
27 using the IPCC Tier 1 default emission factor (19.57 metric tons CO₂/million cubic meters of coal bed
28 methane (CBM) produced) and quantity of coal seam gas recovered and utilized. Data on annual
29 quantity of coal seam gas recovered and utilized are available from GHGRP and state sales data (EPA
30 2024; DMME 2024; ERG 2024; GSA 2024; WVGES 2024). The quantity of coal seam gas recovered and
31 destroyed without energy recovery (e.g., VAM projects with RTO) is deducted from the total coal seam
32 gas recovered quantity (McElroy OVS 2023).

1 **Step 1.3: Estimate Fugitive CO₂ Emissions from Flaring**

2 The IPCC method includes combustion CO₂ emissions from gas recovered for non-energy uses (i.e.,
3 flaring, or catalytic oxidation) under fugitive CO₂ emission estimates for underground coal mining. In
4 effect, these emissions, though occurring through stationary combustion, are categorized as fugitive
5 emissions in the *Inventory*. EPA estimated CO₂ emissions from methane flaring using the following
6 equation:

7 **Equation 3-2: Estimating CO₂ Emissions from Drained Methane Flared or Catalytically**
8 **Oxidized**

9
$$CO_2 \text{ from flaring}$$

10
$$= 0.98 \times \text{Volume of methane flared} \times \text{Conversion Factor}$$

11
$$\times \text{Stoichiometric Mass Factor}$$

12 In 2023, there was a single mine that reported destruction of recovered methane through flaring without
13 energy use and by regenerative thermal oxidation (RTO). Annual data for 2023 were obtained from the
14 mine's offset verification statement (OVS) submitted to the California Air Resources Board (CARB) for
15 the RTO project and from the GHGRP for the flares (McElroy OVS 2023; EPA 2024).

16 **Step 2: Surface Mining**

17 EPA estimated fugitive CO₂ emissions from surface mining using the IPCC Tier 1 emission factor (0.44
18 m³/metric ton) and annual coal production from surface mines (EIA 2024).

19 **Uncertainty – TO BE UPDATED FOR FINAL REPORT**

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

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

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

1 records, which has reduced the uncertainty from previous estimation methods that were based on
 2 information from coal industry contacts.

3 Surface mining and post-mining emissions are associated with considerably more uncertainty than
 4 underground mines, because of the difficulty in developing accurate emission factors from field
 5 measurements. However, since underground coal mining, as a general matter, results in significantly
 6 larger CH₄ emissions due to production of higher-rank coal and greater depth, and estimated emissions
 7 from underground mining constitute the majority of estimated total coal mining CH₄ emissions, the
 8 uncertainty associated with underground emissions is the primary factor that determines overall
 9 uncertainty.

10 The major sources of uncertainty for estimates of fugitive CO₂ emissions are the Tier 1 IPCC default
 11 emission factors used for underground mining (-50 percent to +100 percent) and surface mining (-67
 12 percent to +200 percent) (IPCC 2019). Additional sources of uncertainty for fugitive CO₂ emission
 13 estimates include EIA’s annual coal production data and data used for gas recovery projects, such as
 14 GHGRP data, state gas sales data, and VAM estimates for the single mine that operates an active VAM
 15 project. Uncertainty ranges for these additional data sources are already available, as these are the
 16 same data sources used for CH₄ emission estimates.

17 The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-39. Coal
 18 mining CH₄ emissions in 2022 were estimated to be between 34.8 and 47.8 MMT CO₂ Eq. at a 95 percent
 19 confidence level. This indicates a range of 20.3 percent below to 9.5 percent above the 2022 emission
 20 estimate of 43.6 MMT CO₂ Eq. Coal mining fugitive CO₂ emissions in 2022 were estimated to be between
 21 0.8 and 4.3 MMT CO₂ Eq. at a 95 percent confidence level. This indicates a range of 68.5 percent below
 22 to 75.4 percent above the 2022 emission estimate of 2.5 MMT CO₂ Eq.

23 **Table 3-39: Approach 2 Quantitative Uncertainty Estimates for CH₄ and CO₂ Emissions**
 24 **from Coal Mining (MMT CO₂ Eq. and Percent)**

Source	Gas	2022 Emission Estimate (MMT CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			Lower Bound	Upper Bound	Lower Bound (%)	Upper Bound (%)
Coal Mining	CH ₄	43.6	34.8	47.8	-20%	+9%
	CO ₂	2.5	0.8	4.3	-69%	+75%

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

26 QA/QC and Verification

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

33 Emission estimates for coal mining rely in large part on data reported by coal mines to EPA’s GHGRP.
 34 EPA verifies annual facility-level reports through a multi-step process to identify potential errors and

1 ensure that data submitted to EPA are accurate, complete, and consistent. All reports submitted to EPA
2 are evaluated by electronic validation and verification checks. If potential errors are identified, EPA will
3 notify the reporter, who can resolve the issue either by providing an acceptable response describing why
4 the flagged issue is not an error or by correcting the flagged issue and resubmitting their annual report.
5 Additional QA/QC and verification procedures occur for each GHGRP subpart. No QA/QC issues or
6 errors were identified in the 2023 Subpart FF data.

7 Recalculations Discussion

8 Time series recalculations were performed due to revised historical data from state natural gas sales
9 databases for three mines, which are used to estimate avoided CH₄ emissions from CH₄ recovered and
10 used. As a result of recalculations, CH₄ emissions decreased by an average of less than 0.001 percent
11 across the time series, compared to the previous *Inventory*. The biggest increase in CH₄ emissions was
12 in 1991 where emissions increased by 0.004 percent, compared to the previous *Inventory*. The biggest
13 decrease in CH₄ emissions was in 2011 (less than 0.001 percent). As a result of recalculations, there
14 was a very minor increase in CH₄ emissions in 2022 (less than 0.001 percent), compared to the previous
15 *Inventory*.

16 Planned Improvements

17 EPA is assessing planned improvements for future reports, but currently has no specific planned
18 improvements for estimating CH₄ and CO₂ emissions from underground and surface mining and CH₄
19 emissions from post-mining.

20 3.5 Abandoned Underground Coal Mines 21 (Source Category 1B1a)

22 Underground coal mines contribute the largest share of coal mine methane (CMM) emissions, with
23 active underground mines the leading source of underground emissions. However, mines also continue
24 to release CH₄ after closure. As mines mature and coal seams are mined through, mines are closed and
25 abandoned. Many are sealed and some flood through intrusion of groundwater or surface water into the
26 void. Shafts or portals are generally filled with gravel and capped with a concrete seal, while vent pipes
27 and boreholes are plugged in a manner similar to oil and gas wells. Some abandoned mines are vented
28 to the atmosphere to prevent the buildup of CH₄ that may find its way to surface structures through
29 overburden fractures. As work stops within the mines, CH₄ liberation decreases but it does not stop
30 completely. Following an initial decline, abandoned mines can liberate CH₄ at a near-steady rate over an
31 extended period of time, or if flooded, produce gas for only a few years. The gas can migrate to the
32 surface through the conduits described above, particularly if they have not been sealed adequately. In
33 addition, diffuse emissions can occur when CH₄ migrates to the surface through cracks and fissures in
34 the strata overlying the coal mine. The following factors influence abandoned mine emissions:

- 35 • Time since abandonment;
- 36 • Gas content and adsorption characteristics of coal;

- 1 • CH₄ flow capacity of the mine;
- 2 • Mine flooding;
- 3 • Presence of vent holes; and
- 4 • Mine seals.

5 Annual gross abandoned mine CH₄ emissions ranged from 8.1 to 12.1 MMT CO₂ Eq. from 1990 to 2023,
 6 varying, in general, by less than 1 percent to approximately 19 percent from year to year. Fluctuations
 7 were due mainly to the number of mines closed during a given year as well as the magnitude of the
 8 emissions from those mines when active. Gross abandoned mine emissions peaked in 1996 (12.1 MMT
 9 CO₂ Eq.) due to the large number of gassy mine⁶³ closures from 1994 to 1996 (70 gassy mines closed
 10 during the three-year period). In spite of this rapid rise, abandoned mine emissions have been generally
 11 on the decline since 1996. Since 2002, there have been fewer than twelve gassy mine closures each
 12 year. In 2023 there was one gassy mine closure. Gross abandoned mine emissions decreased slightly
 13 from 9.1 MMT CO₂ Eq. (324 kt CH₄) in 2022 to 9.0 (323 kt CH₄) MMT CO₂ Eq. in 2023 (see Table 3-40 and
 14 Table 3-41). Gross emissions are reduced by CH₄ recovered and used at 62 mines, resulting in net
 15 emissions in 2023 of 6.1 MMT CO₂ Eq. (219 kt CH₄).

16 **Table 3-40: CH₄ Emissions from Abandoned Coal Mines (MMT CO₂ 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

17 NO (Not Occurring)

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

19 **Table 3-41: CH₄ 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

20 NO (Not Occurring)

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

22 Methodology and Time-Series Consistency

23 Estimating CH₄ emissions from an abandoned coal mine requires predicting the emissions of a mine
 24 from the time of abandonment through the inventory year of interest. The flow of CH₄ from the coal to
 25 the mine void is primarily dependent on the mine’s emissions when active and the extent to which the
 26 mine is flooded or sealed. The CH₄ emission rate before abandonment reflects the gas content of the
 27 coal, the rate of coal mining, and the flow capacity of the mine in much the same way as the initial rate
 28 of a water-free conventional gas well reflects the gas content of the producing formation and the flow
 29 capacity of the well. A well or a mine that produces gas from a coal seam and the surrounding strata will
 30 produce less gas through time as the reservoir of gas is depleted. Depletion of a reservoir will follow a

⁶³ A mine is considered a “gassy” mine if it emits more than 100 thousand cubic feet of CH₄ per day (100 Mcfd).

1 predictable pattern depending on the interplay of a variety of natural physical conditions imposed on the
2 reservoir. The depletion of a reservoir is commonly modeled by mathematical equations and mapped as
3 a type curve. Type curves, which are referred to as decline curves, have been developed for abandoned
4 coal mines. Existing data on abandoned mine emissions through time, although sparse, appear to fit the
5 hyperbolic type of decline curve used in forecasting production from natural gas wells.

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

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

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

$$27 \quad q = q_i (1 + bD_i t)^{\left(-\frac{1}{b}\right)}$$

28 where,

29	q	=	Gas flow rate at time t in million cubic feet per day (mmcf/d)
30	q _i	=	Initial gas flow rate at time zero (t ₀), mmcf/d
31	b	=	The hyperbolic exponent, dimensionless
32	D _i	=	Initial decline rate, 1/year
33	t	=	Elapsed time from t ₀ (years)

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

36 The decline curves created to model the gas emission rate of coal mines must account for factors that
37 decrease the rate of emissions after mining activities cease, such as sealing and flooding. Based on field
38 measurement data, it was assumed that most U.S. mines prone to flooding will become completely
39 flooded within eight years and therefore will no longer have any measurable CH₄ emissions. Based on
40 this assumption, an average decline rate for flooded mines was established by fitting a decline curve to
41 emissions from field measurements. An exponential equation was developed from emissions data
42 measured at eight abandoned mines known to be filling with water located in two of the five basins.

1 Using a least squares, curve-fitting algorithm, emissions data were matched to the exponential equation
 2 shown below. For this analysis of flooded abandoned mines, there was not enough data to establish
 3 basin-specific equations, as was done with the vented, non-flooding mines (EPA 2004). This decline
 4 through time can be empirically expressed as:

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

6
$$q = q_i e^{(-Dt)}$$

7 where,

- 8 q = Gas flow rate at time t in mmcf/d
 9 q_i = Initial gas flow rate at time zero (t₀), mmcf/d
 10 D = Decline rate, 1/year
 11 t = Elapsed time from t₀ (years)

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

22 For active coal mines, those mines producing over 100 thousand cubic feet per day (Mcf/d) of CH₄
 23 account for about 98 percent of all CH₄ emissions. This same relationship is assumed for abandoned
 24 mines. It was determined that the 532 abandoned mines closed since 1972 produced CH₄ emissions
 25 greater than 100 Mcfd when active. Further, the status of 308 of the 532 mines (or 58 percent) is known
 26 to be either: 1) vented to the atmosphere; 2) sealed to some degree (either earthen or concrete seals); or
 27 3) flooded (enough to inhibit CH₄ flow to the atmosphere). The remaining 42 percent of the mines whose
 28 status is unknown were placed in one of these three categories by applying a probability distribution
 29 analysis based on the known status of other mines located in the same coal basin (EPA 2004). Table
 30 3-42 presents the count of mines by post-abandonment state, based on EPA’s probability distribution
 31 analysis.

32 **Table 3-42: Number of Gassy Abandoned Mines Present in U.S. Basins in 2023,**
 33 **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

1 Inputs to the decline equation require the average CH₄ emission rate prior to abandonment and the date
2 of abandonment. Generally, these data are available for mines abandoned after 1971; however, such
3 data are largely unknown for mines closed before 1972. Information that is readily available, such as
4 coal production by state and county, is helpful but does not provide enough data to directly employ the
5 methodology used to calculate emissions from mines abandoned before 1972. It is assumed that pre-
6 1972 mines are governed by the same physical, geologic, and hydrologic constraints that apply to post-
7 1971 mines; thus, their emissions may be characterized by the same decline curves.

8 During the 1970s, 78 percent of CH₄ emissions from coal mining came from seventeen counties in seven
9 states. Mine closure dates were obtained for two states, Colorado and Illinois, for the hundred-year
10 period extending from 1900 through 1999. The data were used to establish a frequency of mine closure
11 histogram (by decade) and applied to the other five states with gassy mine closures. As a result, basin-
12 specific decline curve equations were applied to the 145 gassy coal mines estimated to have closed
13 between 1920 and 1971 in the United States, representing 78 percent of the emissions. State-specific,
14 initial emission rates were used based on average coal mine CH₄ emission rates during the 1970s (EPA
15 2004).

16 Abandoned mine emission estimates are based on all closed mines known to have active mine CH₄
17 ventilation emission rates greater than 100 Mcfd at the time of abandonment. For example, for 1990 the
18 analysis included 145 mines closed before 1972 and 258 mines closed between 1972 and 1990. Initial
19 emission rates based on MSHA reports, time of abandonment, and basin-specific decline curves
20 influenced by a number of factors were used to calculate annual emissions for each mine in the
21 database (MSHA 2023). Coal mine degasification data are not available for years prior to 1990, thus the
22 initial emission rates used reflect only ventilation emissions for pre-1990 closures. Methane
23 degasification amounts were added to the quantity of CH₄ vented to determine the total CH₄ liberation
24 rate for all mines that closed between 1992 and 2023. Since the sample of gassy mines described above
25 is assumed to account for 78 percent of the pre-1972 and 98 percent of the post-1971 abandoned mine
26 emissions, the modeled results were multiplied by 1.22 and 1.02, respectively, to account for all U.S.
27 abandoned mine emissions.

28 From 1993 through 2023, emission totals were downwardly adjusted to reflect CH₄ emissions avoided
29 from abandoned mines with CH₄ recovery and use or destruction systems. Currently, there are 62
30 abandoned mines with recovery projects, including 11 projects at mines abandoned before 1972 (pre-
31 1972 mines) (EPA 2004, CMOP 2024). Because CH₄ recovered by these projects is expected to decline
32 with the age of the mine, CH₄ recovery is assumed to be the total estimated CH₄ liberated based on the
33 mine's decline function except for three recovery projects where additional data are available (COGIS
34 2018, MSHA 2024).⁶⁴

35 The *Inventory* totals were not adjusted for abandoned mine CH₄ emissions avoided from 1990 through
36 1992 due to unavailability of data. Avoided CH₄ emissions from pre-1972 abandoned mines are
37 estimated by multiplying the total estimated emissions from these mines in each decade by the fraction
38 of mines with recovery projects in that decade. For recovery projects at pre-1972 abandoned mines, four
39 projects are at mines abandoned in the 1920s, three in the 1930s, two in the 1950s, and two in the 1960s
40 (EPA 2004).

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.

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

11 Uncertainty

12 A quantitative uncertainty analysis was conducted for the abandoned coal mine source category using
 13 the IPCC-recommended Approach 2 uncertainty estimation methodology. The uncertainty analysis
 14 provides for the specification of probability density functions for key variables within a computational
 15 structure that mirrors the calculation of the *Inventory* estimate. The results provide the range within
 16 which, with 95 percent certainty, emissions from this source category are likely to fall.

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

25 The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-43. Annual
 26 abandoned coal mine CH₄ emissions in 2023 were estimated to be between 4.8 and 7.3 MMT CO₂ Eq. at
 27 a 95 percent confidence level. This indicates a range of 21 percent below to 20 percent above the 2023
 28 emission estimate of 6.1 MMT CO₂ Eq. One of the reasons for the relatively narrow range is that mine-
 29 specific data is available for use in the methodology for mines closed in 1972 and later years. Emissions
 30 from mines closed prior to 1972 have the largest degree of uncertainty because no mine-specific CH₄
 31 liberation rates at the time of abandonment exist.

32 **Table 3-43: Approach 2 Quantitative Uncertainty Estimates for CH₄ Emissions from**
 33 **Abandoned Underground Coal Mines (MMT CO₂ 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	4.8	7.3	-21%	+20%

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

1 QA/QC and Verification

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

8 Recalculations Discussion

9 Eleven new abandoned mine methane recovery projects were added to the AMM model during the
10 current *Inventory* (CMOP 2024, GMI 2024, ACR 2024). CMOP, GMI, and ACR data indicate 10 of these
11 recovery projects were started in 2021 and one in 2022. Time series recalculations were performed for
12 2021 and 2022 by adding in the recovery project(s) and rerunning the 2021 and 2022 AMM models. As a
13 result of recalculations, CH₄ emissions decreased by one percent in 2021 and three percent in 2022,
14 compared to the previous *Inventory*.

15 3.6 Petroleum Systems (Source Category 16 1B2a)

17 This category (1B2a) is defined in the IPCC methodological guidance as fugitive emissions from
18 petroleum systems, which per IPCC guidelines include emissions from leaks, venting, and flaring.
19 Methane emissions from petroleum systems are primarily associated with onshore and offshore crude
20 oil exploration, production, transportation, and refining operations. During these activities, CH₄ is
21 released to the atmosphere as emissions from leaks, venting (including emissions from operational
22 upsets), and flaring. Carbon dioxide emissions from petroleum systems are primarily associated with
23 onshore and offshore crude oil production and refining operations. Note, CO₂ emissions in petroleum
24 systems exclude all combustion emissions (e.g., engine combustion) except for flaring CO₂ emissions.
25 All combustion CO₂ emissions (except for flaring) are accounted for in the fossil fuel combustion
26 chapter (see Section 3.1). Emissions of N₂O from petroleum systems are primarily associated with
27 flaring. Total greenhouse gas emissions (CH₄, CO₂, and N₂O) from petroleum systems in 2023 were 60.2
28 MMT CO₂ Eq., an increase of 1 percent from 1990, primarily due to increases in CO₂ emissions. Total
29 emissions decreased by 6 percent from 2010 levels and have increased by 3 percent since 2022. Total
30 CO₂ emissions from petroleum systems in 2023 were 22.5 MMT CO₂ (22,458 kt CO₂), 2.3 times higher
31 than in 1990. Total CO₂ emissions in 2023 were 1.6 times higher than in 2010 and 2 percent higher than
32 in 2022. Total CH₄ emissions from petroleum systems in 2023 were 37.8 MMT CO₂ Eq. (1,348 kt CH₄), a
33 decrease of 25 percent from 1990. Since 2010, total CH₄ emissions decreased by 25 percent; and since
34 2022, CH₄ emissions increased by 4 percent. Total N₂O emissions from petroleum systems in 2023 were
35 0.021 MMT CO₂ Eq. (0.079 kt N₂O), 1.5 times higher than in 1990, 1.2 times higher than in 2010, and 56
36 percent lower than in 2022. Since 1990, U.S. oil production has increased by 69 percent. In 2023, U.S. oil
37 production was 186 percent higher than in 2010 and 8 percent higher than in 2022.

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

- 5 • Updates to oil and gas production volumes using the most recent data from the United States
6 Energy Information Administration (EIA)
- 7 • Recalculations due to Greenhouse Gas Reporting Program (GHGRP) submission revisions
- 8 • Methodological updates for offshore production in the Gulf of America

9 Updated data on well counts, oil and gas production volumes, and produced water volumes from
10 Enverus were not available for Public Review estimates, and 2023 data were set equal to 2022.

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

12 *Exploration.* Exploration includes well drilling, testing, and completions. Exploration accounts for less
13 than 0.5 percent of total CH₄ emissions (including leaks, vents, and flaring) from petroleum systems in
14 2023. The predominant sources of CH₄ emissions from exploration are hydraulically fractured oil well
15 completions. Other sources include well testing, well drilling, and well completions without hydraulic
16 fracturing. Since 1990, exploration CH₄ emissions have decreased 95 percent, and while the number of
17 hydraulically fractured wells completed increased 64 percent, there were decreases in the fraction of
18 such completions without reduced emissions completions (RECs) or flaring. Emissions of CH₄ from
19 exploration were highest in 2008, over 62 times higher than in 2023; and lowest in 2022. Emissions of
20 CH₄ from exploration increased 10 percent from 2022 to 2023, due to an increase in emissions from
21 hydraulically fractured oil well completions without RECs. Exploration accounts for 2 percent of total
22 CO₂ emissions (including leaks, vents, and flaring) from petroleum systems in 2023. Emissions of CO₂
23 from exploration in 2023 were 21 percent higher than in 1990, and increased by 50 percent from 2022,
24 largely due to an increase in emissions from hydraulically fractured oil well completions with REC and
25 flaring (by 78 percent from 2022). Emissions of CO₂ from exploration were highest in 2014, over 8 times
26 higher than in 2023. Exploration accounts for 1 percent of total N₂O emissions from petroleum systems
27 in 2023. Emissions of N₂O from exploration in 2023 are 22 percent higher than in 1990, and 59 percent
28 higher than in 2022, due to hydraulically fractured oil well completions with flaring.

29 *Production.* Production accounts for 97 percent of total CH₄ emissions (including leaks, vents, and
30 flaring) from petroleum systems in 2023. The predominant sources of emissions from production field
31 operations are pneumatic controllers, equipment leaks, offshore oil platforms, produced water, gas
32 engines, chemical injection pumps, and associated gas flaring. In 2023, these seven sources together
33 accounted for 91 percent of the CH₄ emissions from production. Since 1990, CH₄ emissions from
34 production have decreased by 20 percent primarily due to decreases in emissions from offshore
35 production. Overall, production segment CH₄ emissions increased by 4 percent from 2022 levels due
36 primarily to equipment leaks. Production emissions account for 85 percent of the total CO₂ emissions
37 (including leaks, vents, and flaring) from petroleum systems in 2023. The principal sources of CO₂
38 emissions are associated gas flaring, miscellaneous production flaring, and oil tanks with flares. In
39 2023, these three sources together accounted for 97 percent of the CO₂ emissions from production. In
40 2023, CO₂ emissions from production were 3.2 times higher than in 1990, due to increases in flaring
41 emissions from associated gas flaring, miscellaneous production flaring, and tanks. Overall, in 2023,
42 production segment CO₂ emissions increased by 1 percent from 2022 levels primarily due to increases
43 in miscellaneous production flaring in the Permian Basin. Production emissions accounted for 63

1 percent of the total N₂O emissions from petroleum systems in 2023. The principal sources of N₂O
 2 emissions are oil tanks with flares, associated gas flaring, and miscellaneous production flaring,
 3 accounting for 82% of N₂O emissions from the production segment in 2023. In 2023, N₂O emissions
 4 from production were 2 times higher than in 1990 and were 67 percent greater than in 2022.

5 *Crude Oil Transportation.* Emissions from crude oil transportation account for a very small percentage of
 6 the total emissions (including leaks, vents, and flaring) from petroleum systems. Crude oil
 7 transportation activities account for 0.7 percent of total CH₄ emissions from petroleum systems.
 8 Emissions from tanks, marine loading, and truck loading operations accounted for 81 percent of CH₄
 9 emissions from crude oil transportation in 2023. Since 1990, CH₄ emissions from transportation have
 10 increased by 37 percent. In 2023, CH₄ emissions from transportation increased by 6 percent from 2022
 11 levels. Crude oil transportation activities account for less than 0.01 percent of total CO₂ emissions from
 12 petroleum systems. Emissions from tanks, marine loading, and truck loading operations account for 81
 13 percent of CO₂ emissions from crude oil transportation.

14 *Crude Oil Refining.* Crude oil refining processes and systems account for 2 percent of total CH₄
 15 emissions from petroleum systems in 2023. This low share is because most of the CH₄ in crude oil is
 16 removed or escapes before the crude oil is delivered to the refineries. There is a negligible amount of
 17 CH₄ in all refined products. Within refineries, flaring accounts for 45 percent of the CH₄ emissions, while
 18 delayed cokers, uncontrolled blowdowns, and equipment leaks account for 17, 13 and 11 percent,
 19 respectively. CH₄ emissions from refining of crude oil have decreased by 12 percent since 1990, and
 20 decreased by 4 percent from 2022; however, like the transportation subcategory, this increase has had
 21 little effect on the overall emissions of CH₄ from petroleum systems. Crude oil refining processes and
 22 systems account for 13 percent of total CO₂ emissions from petroleum systems. Of the total CO₂
 23 emissions from refining, almost all (about 99 percent) of it comes from flaring.⁶⁵ Since 1990, refinery
 24 CO₂ emissions decreased by 10 percent and have increased by 1 percent from 2022 levels, due to
 25 changes in flaring emissions. Flaring occurring at crude oil refining processes and systems accounts for
 26 36 percent of total N₂O emissions from petroleum systems. In 2023, refinery N₂O emissions increased
 27 by 3 percent since 1990 and increased by 1 percent from 2022 levels.

28 **Table 3-44: Total Greenhouse Gas Emissions (CO₂, CH₄, and N₂O) from Petroleum**
 29 **Systems (MMT CO₂ Eq.)**

Activity	1990	2005	2019	2020	2021	2022	2023
Exploration	3.4	5.7	2.5	1.1	0.8	0.4	0.6
Production	52.2	47.3	88.9	74.3	64.6	54.1	55.8
Transportation	0.2	0.1	0.3	0.2	0.2	0.2	0.3
Crude Refining	3.9	4.5	4.4	3.6	3.7	3.5	3.5
Total	59.6	57.7	96.1	79.3	69.3	58.3	60.2

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

⁶⁵ Petroleum systems includes emissions from leaks, venting, and flaring. In many industries, including petroleum refineries, the largest source of onsite CO₂ emissions is often fossil fuel combustion, which is covered in Section 3.1 of this chapter.

1 **Table 3-45: CH₄ Emissions from Petroleum Systems (MMT CO₂ 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	41.2	49.0	49.1	44.1	35.2	36.7
Pneumatic Controllers	21.3	21.8	24.2	30.6	26.9	18.4	16.1
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	3.1	3.1	6.6
Gas Engines	2.3	2.0	2.6	2.5	2.4	2.5	2.5
Produced Water	2.6	1.8	2.8	2.5	2.6	2.7	2.7
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	47.4	50.6	50.4	45.2	36.2	37.8

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

3 **Table 3-46: CH₄ Emissions from Petroleum Systems (kt CH₄)**

Activity	1990	2005	2019	2020	2021	2022	2023
Exploration	106	189	16	12	7	4	5
Production	1,648	1,470	1,751	1,755	1,575	1,257	1,311
Pneumatic Controllers	762	780	864	1,094	962	657	575
Offshore Production	374	261	155	108	104	104	104
Equipment Leaks	82	101	138	113	112	110	236
Gas Engines	81	70	93	89	87	88	89
Produced Water	92	64	99	90	92	95	95
Chemical Injection Pumps	47	80	117	93	82	74	63
Assoc Gas Flaring	20	14	91	47	35	30	33
Other Sources	189	100	193	121	101	100	116
Crude Oil Transportation	7	5	9	8	8	8	9
Refining	27	30	31	26	25	25	24
Total	1,787	1,694	1,807	1,800	1,615	1,295	1,348

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

5 **Table 3-47: CO₂ Emissions from Petroleum Systems (MMT CO₂)**

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	6.1	39.8	25.2	20.5	18.9	19.1
Transportation	+	+	+	+	+	+	+
Crude Refining	3.2	3.6	3.6	2.9	3.0	2.8	2.9
Total	9.6	10.2	45.4	28.9	24.1	22.0	22.5

6 + Does not exceed 0.05 MMT CO₂

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

1 **Table 3-48: CO₂ Emissions from Petroleum Systems (kt CO₂)**

Activity	1990	2005	2019	2020	2021	2022	2023
Exploration	398	465	2,053	798	602	321	481
Production	6,016	6,147	39,835	25,201	20,489	18,896	19,114
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	9,589	10,215	45,450	28,874	24,094	22,039	22,458

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

3 **Table 3-49: N₂O Emissions from Petroleum Systems (Metric Tons CO₂ Eq.)**

Activity	1990	2005	2019	2020	2021	2022	2023
Exploration	180	209	822	353	290	138	219
Production	6,623	6,159	22,118	13,872	11,975	40,607	13,294
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	14,065	14,611	32,224	21,748	20,132	48,132	21,010

4 NE (Not Estimated)

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

6 **Table 3-50: N₂O Emissions from Petroleum Systems (Metric Tons N₂O)**

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	23.2	83.5	52.3	45.2	153.2	50.2
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	55.1	121.6	82.1	76.0	181.6	79.3

7 NE (Not Estimated)

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

9 Methodology and Time-Series Consistency

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

12 Petroleum systems includes emission estimates for activities occurring in petroleum systems from the
13 oil wellhead through crude oil refining, including activities for crude oil exploration, production field
14 operations, crude oil transportation activities, and refining operations. Generally, emissions are
15 estimated for each activity by multiplying emission factors (e.g., emission rate per equipment or per
16 activity) by corresponding activity data (e.g., equipment count or frequency of activity). Certain sources
17 within petroleum refineries are developed using an IPCC Tier 3 approach (i.e., all refineries in the nation
18 report facility-level emissions data to the GHGRP, which are included directly in the national emissions
19 estimates here). Other estimates are developed with a Tier 2 approach. Tier 1 approaches are not used.

20 *Emission Factors.* Key references for emission factors include *Methane Emissions from the Natural Gas*
21 *Industry by the Gas Research Institute and EPA (GRI/EPA 1996)*, *Estimates of Methane Emissions from*
22 *the U.S. Oil Industry (EPA 1999)*, *Compilation of Air Pollutant Emission Factors, AP-42 (EPA 1997)*, *Global*
23 *Emissions of Methane from Petroleum Sources (API 1992)*, consensus of industry peer review panels,

1 Bureau of Ocean Energy Management (BOEM) reports, *Nonpoint Oil and Gas Emission Estimation Tool*
2 (EPA 2017), and analysis of GHGRP data (EPA 2024).

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

8 The emission factors for well testing and associated gas venting and flaring were developed using year-
9 specific GHGRP data for years 2015 forward; earlier years in the time series use 2015 emission factors.
10 For miscellaneous production flaring, year-specific emission factors were developed for years 2015
11 forward from GHGRP data, an emission factor of 0 (assumption of no flaring) was assumed for 1990
12 through 1992, and linear interpolation was applied to develop emission factors for 1993 through 2014.
13 For more information, please see memoranda available online.⁶⁷ For offshore oil production, emission
14 factors were calculated using BOEM data for offshore facilities in federal waters of the Gulf of America
15 (and these data were also applied to facilities located in state waters of the Gulf of America) and GHGRP
16 data for offshore facilities off the coasts of California and Alaska. For many other sources, emission
17 factors were held constant for the period 1990 through 2023, and trends in emissions reflect changes in
18 activity levels. Emission factors from EPA 1999 are used for all other production and transportation
19 activities.

20 For associated gas venting and flaring and miscellaneous production flaring, emission factors were
21 developed on a production basis (i.e., emissions per unit oil produced). Additionally, for these two
22 sources, basin-specific activity and emission factors were developed for each basin that in any year
23 from 2011 forward contributed at least 10 percent of total source emissions (on a CO₂ Eq. basis) in the
24 GHGRP. For associated gas venting and flaring, basin-specific factors were developed for four basins:
25 Williston, Permian, Gulf Coast, and Anadarko. For miscellaneous production flaring, basin-specific
26 factors were developed for three basins: Williston, Permian, and Gulf Coast. For each source, data from
27 all other basins were combined, and activity and emission factors were developed for the other basins
28 as a single group.

29 For pneumatic controllers and tanks, basin-specific emission factors were calculated for all the basins
30 reporting to the GHGRP. These emission factors were calculated for all the years with applicable GHGRP
31 data (i.e., 2011 - 2023 or 2015 - 2023). For the remaining basins (i.e., basins not reporting to the GHGRP),
32 Subpart W average emission factors were used. For more information, please see memoranda available
33 online.³

34 For the exploration and production segments, in general, CO₂ emissions for each source were estimated
35 with GHGRP data or by multiplying CO₂ content factors by the corresponding CH₄ data, as the CO₂
36 content of gas relates to its CH₄ content. Sources with CO₂ emission estimates calculated using GHGRP
37 data include HF completions and workovers, associated gas venting and flaring, tanks, well testing,
38 pneumatic controllers, chemical injection pumps, miscellaneous production flaring, and certain
39 offshore production facilities (those located off the coasts of California and Alaska). For these sources,
40 CO₂ was calculated using the same methods as used for CH₄. Carbon dioxide emission factors for
41 offshore oil production in the Gulf of America were derived using data from BOEM, following the same

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

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

1 methods as used for CH₄ estimates. For other sources, the production field operations emission factors
2 for CO₂ are generally estimated by multiplying the CH₄ emission factors by a conversion factor, which is
3 the ratio of CO₂ content and CH₄ content in produced associated gas.

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

9 For crude oil transportation, emission factors for CH₄ were largely developed using data from EPA
10 (1997), API (1992), and EPA (1999). Emission factors for CO₂ were estimated by multiplying the CH₄
11 emission factors by a conversion factor, which is the ratio of CO₂ content and CH₄ content in whole
12 crude post-separator.

13 For petroleum refining activities, year-specific emissions from 2010 forward were directly obtained from
14 EPA's GHGRP. All U.S. refineries have been required to report CH₄, CO₂, and N₂O emissions for all major
15 activities starting with emissions that occurred in 2010. The reported total CH₄, CO₂, and N₂O emissions
16 for each activity was used for the emissions in each year from 2010 forward. To estimate emissions for
17 1990 to 2009, the 2010 to 2013 emissions data from GHGRP along with the refinery feed data for 2010 to
18 2013 were used to derive CH₄ and CO₂ emission factors (i.e., sum of activity emissions/sum of refinery
19 feed) and 2010 to 2017 data were used to derive N₂O emission factors; these emission factors were then
20 applied to the annual refinery feed in years 1990 to 2009. GHGRP delayed coker CH₄ emissions for 2010
21 through 2017 were increased using the ratio of certain reported emissions for 2018 to 2017, to account
22 for a more accurate GHGRP calculation methodology that was implemented starting in reporting year
23 2018.

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

26 *Activity Data.* References for activity data include Enverus data (Enverus 2023), Energy Information
27 Administration (EIA) reports, *Methane Emissions from the Natural Gas Industry by the Gas Research*
28 *Institute and EPA (EPA/GRI 1996), Estimates of Methane Emissions from the U.S. Oil Industry (EPA 1999),*
29 consensus of industry peer review panels, BOEM reports, the Oil & Gas Journal, the Interstate Oil and
30 Gas Compact Commission, the United States Army Corps of Engineers, and analysis of GHGRP data
31 (EPA 2024).

32 For HF oil well completions and workovers, pneumatic controllers, equipment leaks, chemical injection
33 pumps, and tanks, basin-specific activity factors were calculated for all the basins reporting to the
34 GHGRP. These factors were calculated for all the years with applicable GHGRP data (i.e., 2011 through
35 2023, 2016 through 2023, or 2015 through 2023). For the remaining basins (i.e., basins not reporting to
36 the GHGRP), GHGRP average activity factors were used. For more information, please see memoranda
37 available online.⁶⁸

38 For many sources, complete activity data were not available for all years of the time series. In such
39 cases, one of three approaches was employed to estimate values, consistent with IPCC good practice.
40 Where appropriate, the activity data were calculated from related statistics using ratios developed
41 based on EPA/GRI (1996) and/or GHGRP data. In some cases, activity data are developed by

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

1 interpolating between recent data points (such as from GHGRP) and earlier data points, such as from
2 EPA/GRI (1996). Lastly, in limited instances the previous year’s data were used if current year data were
3 not yet available.

4 A complete list of references for emission factors and activity data by emission source is provided in
5 Annex 3.5. The notation key “IE” is used for CO₂ and CH₄ emissions from venting and flaring in common
6 data tables category 1.B.2. Disaggregating flaring and venting estimates across the *Inventory* would
7 involve the application of assumptions and could result in inconsistent reporting and, potentially,
8 decreased transparency. Data availability varies across segments within oil and gas activities systems,
9 and emission factor data available for activities that include flaring can include emissions from multiple
10 sources (flaring, venting and leaks).

11 As noted above, EPA’s GHGRP data, available starting in 2010 for refineries and in 2011 for other
12 sources, have improved estimates of emissions from petroleum systems. Many of the previously
13 available datasets were collected in the 1990s. To develop a consistent time series for sources with new
14 data, EPA reviewed available information on factors that may have resulted in changes over the time
15 series (e.g., regulations, voluntary actions) and requested stakeholder feedback on trends as well. For
16 most sources, EPA developed annual data for 1993 through 2009 or 2014 by interpolating activity data or
17 emission factors or both between 1992 (when GRI/EPA data are available) and 2010 or 2015 data points.
18 Information on time-series consistency for sources updated in this year’s *Inventory* can be found in the
19 Recalculations Discussion below, with additional detail provided in supporting memos (relevant memos
20 are cited in the Recalculations Discussion). For information on other sources, please see the
21 Methodology and Time-Series Consistency discussion above and Annex 3.5.

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

24 **Uncertainty – TO BE UPDATED FOR FINAL REPORT**

25 EPA conducted a quantitative uncertainty analysis using the IPCC Approach 2 methodology (Monte
26 Carlo Simulation technique) to characterize uncertainty for petroleum systems. For more information on
27 the approach, please see the memoranda *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-*
28 *2016: Natural Gas and Petroleum Systems Uncertainty Estimates (2018 uncertainty memo)* and
29 *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2019: Update for Natural Gas and*
30 *Petroleum Systems CO₂ Uncertainty Estimates (2021 uncertainty memo)*.⁶⁹

31 EPA used Microsoft Excel’s @RISK add-in tool to estimate the 95 percent confidence bound around CH₄
32 and CO₂ emissions from petroleum systems for the current *Inventory*. For the CH₄ uncertainty analysis,
33 EPA focused on the eight highest methane-emitting sources for the year 2022, which together emitted
34 75 percent of methane from petroleum systems in 2022, and extrapolated the estimated uncertainty for
35 the remaining sources. For the CO₂ uncertainty analysis, EPA focused on the five highest-emitting
36 sources for the year 2022 which together emitted 81 percent of CO₂ from petroleum systems in 2022,
37 and extrapolated the estimated uncertainty for the remaining sources. The @RISK add-in provides for
38 the specification of probability density functions (PDFs) for key variables within a computational
39 structure that mirrors the calculation of the inventory estimate. For emission factors that are derived
40 from methane emissions measurement studies, the PDFs are commonly determined to be lognormally

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

1 distributed (GRI/EPA 1996; EPA 1999). For activity data that are derived from national datasets, the PDFs
 2 are set to a uniform distribution (see 2018 and 2021 uncertainty memos). Many emission factors and
 3 activity factors are calculated using subpart W data, and for these, the @RISK add-in determines the
 4 best fitting PDF (e.g., lognormal, gaussian), based on bootstrapping of the underlying data (see 2018 and
 5 2021 uncertainty memos). The IPCC guidance notes that in using this Approach 2 method, "some
 6 uncertainties that are not addressed by statistical means may exist, including those arising from
 7 omissions or double counting, or other conceptual errors, or from incomplete understanding of the
 8 processes that may lead to inaccuracies in estimates developed from models." As a result, the
 9 understanding of the uncertainty of emission estimates for this category evolves and improves as the
 10 underlying methodologies and datasets improve. The uncertainty bounds reported below only reflect
 11 those uncertainties that EPA has been able to quantify and do not incorporate considerations such as
 12 modeling uncertainty, data representativeness, measurement errors, misreporting or misclassification.
 13 To estimate uncertainty for N₂O, EPA applied the uncertainty bounds calculated for CO₂. EPA will seek to
 14 refine this estimate in future *Inventories*.

15 The results presented below provide the 95 percent confidence bound within which actual emissions
 16 from this source category are likely to fall for the year 2022, using the recommended IPCC methodology.
 17 The results of the Approach 2 uncertainty analysis are summarized in Table 3-51. Petroleum systems
 18 CH₄ emissions in 2022 were estimated to be between 32.7 and 48.6 MMT CO₂ Eq., while CO₂ emissions
 19 were estimated to be between 17.9 and 27.4 MMT CO₂ Eq. at a 95 percent confidence level. Petroleum
 20 systems N₂O emissions in 2022 were estimated to be between 0.039 and 0.059 MMT CO₂ Eq. at a 95
 21 percent confidence level.

22 Uncertainty bounds for other years of the time series have not been calculated, but uncertainty is
 23 expected to vary over the time series. For example, years where many emission sources are calculated
 24 with interpolated data would likely have higher uncertainty than years with predominantly year-specific
 25 data. In addition, the emission sources that contribute the most to CH₄ and CO₂ emissions are different
 26 over the time series, particularly when comparing recent years to early years in the time series. For
 27 example, associated gas venting emissions were higher and flaring emissions were lower in early years
 28 of the time series, compared to recent years. Technologies also changed over the time series (e.g.,
 29 reduced emissions completions were not used early in the time series).

30 **Table 3-51: Approach 2 Quantitative Uncertainty Estimates for CH₄ and CO₂**
 31 **Emissions from Petroleum Systems (MMT CO₂ Eq. and Percent)**

Source	Gas	2022 Emission Estimate (MMT CO ₂ Eq.) ^b	Uncertainty Range Relative to Emission Estimate ^a			
			(MMT CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Petroleum Systems	CH ₄	39.6	32.7	48.6	-18%	+23%
Petroleum Systems	CO ₂	22.0	17.9	27.4	-19%	+25%
Petroleum Systems	N ₂ O	0.048	0.039	0.059	-19%	+25%

32 ^a Range of emission estimates estimated by applying the 95 percent confidence intervals obtained from the Monte Carlo
 33 Simulation analysis conducted for the year 2022 CH₄ and CO₂ emissions.

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

1 QA/QC and Verification Discussion

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

5 The petroleum systems emission estimates in the *Inventory* are continually being reviewed and
6 assessed to determine whether emission factors and activity factors accurately reflect current industry
7 practices. A QA/QC analysis was performed for data gathering and input, documentation, and
8 calculation. QA/QC checks are consistently conducted to minimize human error in the emission
9 calculations. EPA performs a thorough review of information associated with new studies, GHGRP data,
10 regulations, public webcasts, and the Natural Gas STAR Program to assess whether the assumptions in
11 the *Inventory* are consistent with current industry practices. EPA has a multi-step data verification
12 process for GHGRP data, including automatic checks during data-entry, statistical analyses on
13 completed reports, and staff review of the reported data. Based on the results of the verification
14 process, EPA follows up with facilities to resolve mistakes that may have occurred.⁷⁰

15 As in previous years, EPA conducted early engagement and communication with stakeholders on
16 updates prior to public review of the current *Inventory*. EPA held a stakeholder webinar on BOEM
17 offshore data updates and greenhouse gas data for oil and gas in November of 2024. EPA released
18 memos detailing updates under consideration and requesting stakeholder feedback. Stakeholder
19 feedback will be evaluated and any resulting updates will be performed for the final version of this
20 *Inventory*.

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

32 A key challenge in using these types of studies to assess *Inventory* results is having a relevant basis for
33 comparison (e.g., the two data sets should have comparable time frames and geographic coverage, and
34 the independent study should assess data from the *Inventory* and not another data set, such as the
35 Emissions Database for Global Atmospheric Research, or “EDGAR”). In an effort to improve the ability to
36 compare the national-level *Inventory* with measurement results that may be at other spatial and
37 temporal scales, EPA has developed a gridded inventory of U.S. anthropogenic methane emissions with
38 0.1 degree x 0.1 degree spatial resolution, monthly temporal resolution, and detailed scale-dependent
39 error characterization.⁷¹ The most recent version of the gridded methane inventory is designed to be
40 consistent with the U.S. EPA’s *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2018*

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

⁷¹ See <https://www.epa.gov/ghgemissions/us-gridded-methane-emissions>.

1 estimates for the years 2012 through 2018. The gridded inventory improves efforts to compare results of
2 this *Inventory* with atmospheric studies.

3 As discussed above, refinery emissions are quantified by using the total emissions reported to GHGRP
4 for the refinery emission categories included in petroleum systems. Subpart Y has provisions that
5 refineries are not required to report under Subpart Y if their emissions fall below certain thresholds.
6 Each year, a review is conducted to determine whether an adjustment is needed to the *Inventory*
7 emissions to include emissions from refineries that stopped reporting to the GHGRP. Based on the
8 review of the most recent GHGRP data, EPA did not identify any additional refineries that would require
9 gap filling. There are a total of 6 refineries that EPA previously identified (i.e., during the 1990 through
10 2022 *Inventory* and prior versions) as not reporting to the GHGRP and continued to gap fill annual
11 emissions for these refineries. EPA used the last reported emissions (by source) for these refineries as
12 proxy to gap fill annual emissions.

13 Recalculations Discussion

14 EPA received information and data related to the emission estimates through GHGRP reporting and
15 presented information to stakeholders regarding the updates under consideration. In December 2024,
16 EPA released a draft memorandum that discussed changes under consideration and requested
17 stakeholder feedback on those changes.⁷² The memorandum cited in the Recalculations Discussion
18 below is: *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2023: Updates Under*
19 *Consideration to Use New Offshore Data (Offshore Production memo)*.

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

23 In addition to the updates to the offshore production sources mentioned above, for certain sources, CH₄
24 and/or CO₂ emissions changed by greater than 0.05 MMT CO₂ Eq., comparing the previous estimate for
25 2022 to the current (recalculated) estimate for 2022. The emissions changes were mostly due to GHGRP
26 data submission revisions. These sources are discussed below and include pneumatic controllers,
27 chemical injection pumps, and refinery flaring.

28 The combined impact of revisions to 2022 petroleum systems CH₄ emission estimates on a CO₂-
29 equivalent basis, compared to the previous *Inventory*, is a decrease from 39.6 to 36.2 MMT CO₂ Eq. (3.4
30 MMT CO₂ Eq., or 8 percent). The recalculations resulted in lower CH₄ emission estimates on average
31 across the 1990 through 2022 time series, compared to the previous *Inventory*, by 0.6 MMT CO₂ Eq., or 1
32 percent.

33 The combined impact of revisions to 2022 petroleum systems CO₂ emission estimates, compared to the
34 previous *Inventory*, is a slight increase from 21.97 to 22.04 MMT CO₂ (0.07 MMT CO₂, or 0.3 percent). The
35 recalculations resulted in lower emission estimates on average across the 1990 through 2022 time
36 series, compared to the previous *Inventory*, by less than 0.05 MMT CO₂ Eq., or 0.01 percent.

37 The combined impact of revisions to 2022 petroleum systems N₂O emission estimates on a CO₂-
38 equivalent basis, compared to the previous *Inventory*, is an increase of 0.001 MMT CO₂, Eq. or 1 percent.

⁷² Stakeholder materials including draft memoranda for the current (i.e., 1990 to 2023) *Inventory* are available at <https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems>.

1 The recalculations resulted in an average increase in emission estimates across the 1990 through 2022
 2 time series, compared to the previous *Inventory*, of 0.001 MMT CO₂ Eq., or 9 percent.

3 In Table 3-52 and Table 3-53 below are categories in petroleum systems with updated methodologies or
 4 with recalculations resulting in a change of greater than 0.05 MMT CO₂ Eq., comparing the previous
 5 estimate for 2022 to the current (recalculated) estimate for 2022. For more information, please see the
 6 discussion below.

7 **Table 3-52: Recalculations of CO₂ in Petroleum Systems (MMT CO₂)**

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	19.1
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	22.0	22.5

8 + Does not exceed 0.05 MMT CO₂ Eq.

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

10 **Table 3-53: Recalculations of CH₄ in Petroleum Systems (MMT CO₂ 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	36.7
Pneumatic Controllers	19.4	18.4	16.1
Chemical Injection Pumps	2.2	2.1	1.8
Offshore Production - GOA Federal Waters	4.6	2.4	2.4
Offshore Production - GOA State Waters	+	+	+
Transportation	0.2	0.2	0.3
Refining	0.7	0.7	0.7
Petroleum Systems Total	39.6	36.2	37.8

11 + Does not exceed 0.05 MMT CO₂ Eq.

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

13 **Exploration**

14 There were no methodological updates for exploration and recalculations for the exploration segment
 15 have resulted in minor changes in calculated CH₄ and CO₂ emissions over the time series. Methane
 16 emissions have decreased by an average of 0.1 percent and CO₂ emissions have increased by an
 17 average of 0.1 percent across the time series, compared to the previous *Inventory*.

1 Production

2 **Offshore Production – GOA Waters (Methodological Update)**

3 EPA updated the calculation methodology for offshore production in the Gulf of America (GOA) to use
 4 new emission factors calculated from year 2021 data from the Bureau of Ocean Energy Management
 5 (BOEM). Offshore production in the GOA occurs in two areas, federal waters and state waters. BOEM
 6 provides periodic emission inventories which account for emissions specific to GOA federal waters
 7 production. Previously, year 2017 BOEM data were the most recent that were incorporated into the
 8 Inventory’s calculation methodology. EPA previously applied emission source-specific emission factors
 9 calculated from BOEM’s 2017 dataset to calculate emissions for all years from 2016 – 2022 for GOA
 10 federal waters. EPA then calculated GOA state waters emissions using the federal waters emissions,
 11 assuming the emissions were equivalent on a production basis. With the release of the BOEM 2021
 12 dataset, EPA calculated new emission source-specific emission factors. EPA applied the same
 13 approach to calculate emission factors from the 2021 BOEM dataset as it did for the prior BOEM
 14 datasets. EPA applied the emission factors calculated from the BOEM 2021 dataset for years 2020 –
 15 2023, maintained the emission factors from the BOEM 2017 dataset for 2016 – 2018, and calculated
 16 emission factors that average both BOEM datasets together for year 2019. This update impacts sources
 17 of vent and leak emissions only, flaring emissions are not affected. Details and additional
 18 considerations for this update are available in the Offshore Production memo.

19 As a result of this methodological update, CH₄ emissions estimates for offshore production in the GOA
 20 are on average 40 percent lower for 2019 - 2022 compared to the previous *Inventory*. The 2022 CH₄
 21 emissions estimate is 48 percent lower than in the previous *Inventory*. The update resulted in CO₂
 22 emissions estimates for offshore production in the GOA that are on average 30 percent lower for 2019 to
 23 2022 compared to the previous *Inventory*. The 2022 CO₂ emissions estimate is 36 percent lower than in
 24 the previous *Inventory*. This methodological update impacted CH₄ and CO₂ estimates for 2019 to 2022,
 25 compared to the previous *Inventory*. The methodological update did not impact emissions for years
 26 prior to 2019; differences in emissions compared to the previous *Inventory* for years prior to 2019 are
 27 due to changes in underlying activity data (e.g., number of offshore complexes, oil and gas production).

28 **Table 3-54: GOA Offshore Production Vent and Leak National CH₄ Emissions (Metric**
 29 **Tons CH₄)**

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
<i>Previous Estimate</i>	308,543	219,893	178,558	167,001	165,720	164,395	NA

30 NA (Not Applicable)

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

32 **Table 3-55: GOA Offshore Production Vent and Leak National CO₂ Emissions (Metric**
 33 **Tons CO₂)**

Source	1990	2005	2019	2020	2021	2022	2023
GOA Federal Waters - Major Complexes	3,010	2,299	1,624	902	869	848	863

Source	1990	2005	2019	2020	2021	2022	2023
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
<i>Previous Estimate</i>	3,702	2,741	2,525	2,359	2,341	2,324	NA

1 NA (Not Applicable)

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

3 ***Pneumatic Controllers (Recalculation with Updated Data)***

4 Methane emissions from onshore production pneumatic controllers are an average of 3 percent lower
5 across the time series and 5 percent lower in 2022, compared to the previous *Inventory*. The emission
6 changes were due to GHGRP data submission revisions.

7 **Table 3-56: Pneumatic Controllers National CH₄ Emissions (Metric Tons CH₄)**

Source	1990	2005	2019	2020	2021	2022	2023
High Bleed Controllers	710,824	477,522	72,774	86,923	45,443	24,176	14,453
Low Bleed Controllers	50,868	64,706	49,673	36,524	45,653	35,104	30,653
Intermittent Bleed Controllers	NO	237,590	741,958	970,267	871,131	598,081	529,475
Total Emissions	761,692	779,819	864,404	1,093,714	962,227	657,361	574,582
<i>Previous Estimate</i>	760,925	811,142	881,203	1,119,352	1,003,063	693,551	NA

8 NA (Not Applicable)

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

10 ***Chemical Injection Pumps (Recalculation with Updated Data)***

11 Methane emissions from chemical injection pumps are on average 1 percent lower across the time
12 series and 7 percent lower in 2022, compared to the previous *Inventory*. The emission changes were due
13 to GHGRP data submission revisions.

14 **Table 3-57: Chemical Injection Pump National CH₄ Emissions (Metric Tons CH₄)**

Source	1990	2005	2019	2020	2021	2022	2023
Chemical Injection Pumps	47,425	79,968	116,786	92,702	81,791	74,237	62,999
<i>Previous Estimate</i>	47,425	79,968	122,967	96,186	85,494	79,712	NA

15 NA (Not Applicable)

16 **Transportation**

17 Recalculations for the transportation segment have resulted in calculated CH₄ and CO₂ emissions over
18 the time series from this segment that are lower (by less than 0.05 percent) than in the previous
19 *Inventory*.

20 **Refining**

21 Recalculations due to resubmitted GHGRP data in the refining segment have resulted in an increase in
22 calculated CH₄ emissions by an average of 3.7 percent across the time series and a decrease of 0.6
23 percent in 2022, compared to the previous *Inventory*.

1 Refining CO₂ emission estimates decreased by an average of 0.1 percent across the time series and
 2 decreased by 1.8 percent in 2022, compared to the previous *Inventory*. This change in emissions is due
 3 to GHGRP resubmissions and was largely due to a change in reported flaring CO₂ emissions.

4 **Table 3-58: Refining National CH₄ Emissions (Metric Tons CH₄)**

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

5 NA (Not Applicable)

6 **Table 3-59: Refining National CO₂ Emissions (kt CO₂)**

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
<i>Previous Estimate</i>	3,174	3,602	3,571	2,893	3,021	2,872	NA

7 NA (Not Applicable)

8 Planned Improvements

9 Planned Improvements for 2025 Inventory

10 EPA did not update the Enverus data for the public review estimates and will do so for the final version of
 11 the 2025 *Inventory*. For this version of the *Inventory*, EPA used 2022 data as proxy for 2023.

12 EPA continues to seek stakeholder feedback on the draft updates included in this public review draft
 13 and may revise the calculations in the *Inventory* based on feedback received. Additional information on
 14 the updates and specific requests for stakeholder feedback can be found in the *Offshore Production*
 15 memo.

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

17 EPA will assess new data received by the Greenhouse Gas Reporting Program and other relevant
 18 programs on an ongoing basis, which may be used to confirm or improve existing estimates and
 19 assumptions. In December 2024, EPA released a memorandum discussing updates under consideration
 20 for a future *Inventory* to incorporate revised GHGRP subpart W emission factors and requested
 21 stakeholder feedback (*Inventory of U.S. Greenhouse Gas Emissions and Sinks: Updates Under*
 22 *Consideration to Use Revised Subpart W Emission Factors*).⁷³

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

⁷³ The memo is available online: <https://www.epa.gov/ghgemissions/stakeholder-process-natural-gas-and-petroleum-systems-1990-2023-inventory>

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

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

In the *Inventory*, CO₂ that is used in non-EOR industrial and commercial applications (e.g., food processing, chemical production) is assumed to be emitted to the atmosphere during its industrial use. These emissions are discussed in the Carbon Dioxide Consumption section, 4.15.

For EOR CO₂, as noted in the *2006 IPCC Guidelines*, “At the Tier 1 or 2 methodology levels [EOR CO₂ is] indistinguishable from fugitive greenhouse gas emissions by the associated oil and gas activities.” In the U.S. estimates for oil and gas fugitive emissions, the Tier 2 emission factors for CO₂ include CO₂ that was originally injected and is emitted along with other gas from leak, venting, and flaring pathways, as measurement data used to develop those factors would not be able to distinguish between CO₂ from EOR and CO₂ occurring in the produced natural gas. Therefore, EOR CO₂ emitted through those pathways is included in CO₂ estimates in 1B2.

IPCC includes methodological guidance to estimate emissions from the capture, transport, injection, and geological storage of CO₂. The methodology is based on the principle that the carbon capture and storage system should be handled in a complete and consistent manner across the entire Energy sector. The approach accounts for CO₂ captured at natural and industrial sites as well as emissions from capture, transport, and use. For storage specifically, a Tier 3 methodology is outlined for estimating and reporting emissions based on site-specific evaluations. However, IPCC (IPCC 2006) notes that if a national regulatory process exists, emissions information available through that process may support development of CO₂ emission estimates for geologic storage.

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

GHGRP data relevant for this *Inventory* estimate consists of national-level annual quantities of CO₂ captured and extracted for EOR applications for 2010 to 2023 and data reported for geologic sequestration from 2016 to 2023. Emissions associated with the use of GHGRP data and TIGS emissions are discussed in the CO₂ Transport, Injection, and Geological Storage section, 3.9.

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 (CH₄, CO₂, and N₂O) from natural gas systems in 2023 were 199.6 MMT CO₂ Eq., a decrease of 21 percent from 1990 and a decrease of 4 percent from 2022, both primarily due to decreases in CH₄ emissions. From 2011, emissions decreased by 10 percent, primarily due to decreases in CH₄ 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 (199.6 MMT CO₂ Eq.), 81 percent are CH₄ emissions (162.0 MMT CO₂ Eq.), 19 percent are CO₂ emissions (37.6 MMT), and less than 0.1 percent are N₂O emissions (0.01 MMT CO₂ Eq.).

Overall, natural gas systems emitted 162.0 MMT CO₂ Eq. (5,784 kt CH₄) of CH₄ in 2023, a 26 percent decrease compared to 1990 emissions, and 6 percent decrease compared to 2022 emissions (see Table 3-61 and Table 3-62). For non-combustion CO₂, a total of 37.6 MMT CO₂ Eq. (37,605 kt) was emitted in 2023, a 16 percent increase compared to 1990 emissions, and a 3 percent increase compared to 2022 levels. The 2023 N₂O emissions were estimated to be 0.01 MMT CO₂ Eq. (0.03 kt N₂O), a 77 percent increase compared to 1990 emissions, and a 55 percent decrease compared to 2022 levels.

The 1990 to 2023 emissions trend is not consistent across segments or gases. Overall, the 1990 to 2023 decrease in CH₄ 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 CH₄ emissions of 23 percent (with onshore production emissions increasing less than 1 percent, offshore production emissions decreasing 98 percent, and gathering and boosting [G&B] emissions increasing 96 percent), and post-meter emissions increasing by 70 percent. The 1990 to 2023 increase in CO₂ emissions is primarily due to an increase in CO₂ emissions in the production segment, where emissions from flaring have increased over time.

Methane and CO₂ emissions from natural gas systems include those resulting from normal operations, routine maintenance, and system upsets. Emissions from normal operations include natural gas engine and turbine uncombusted exhaust, flaring, and leak emissions from system components. Routine maintenance emissions originate from pipelines, equipment, and wells during repair and maintenance activities. Pressure surge relief systems and accidents can lead to system upset emissions. Emissions of N₂O from flaring activities are included in the *Inventory*, with most of the emissions occurring in the processing and production segments. Note, CO₂ emissions exclude all combustion emissions (e.g., engine combustion) except for flaring CO₂ emissions. All combustion CO₂ emissions (except for flaring) are accounted for in Section 3.1.

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

1 2023) to ensure that the trend is representative of changes in emissions. Recalculations in natural gas
2 systems in this year's *Inventory* include:

- 3 • Methodological updates for offshore production in the Gulf of America.
- 4 • Recalculations due to Greenhouse Gas Reporting Program (GHGRP) submission revisions.

5 Updates to well counts and produced water volumes were not available for Public Review estimates,
6 and 2023 data were set equal to 2022.

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

8 Below is a characterization of the six emission subcategories of natural gas systems: exploration,
9 production (including gathering and boosting), processing, transmission and storage, distribution, and
10 post-meter. Each of the segments is described and the different factors affecting CH₄, CO₂, and N₂O
11 emissions are discussed.

12 *Exploration.* Exploration includes well drilling, testing, and completion. Emissions from exploration
13 accounted for 0.1 percent of CH₄ emissions and 0.1 percent of CO₂ emissions from natural gas systems
14 in 2023. Well completions accounted for approximately 87 percent of CH₄ emissions from the
15 exploration segment in 2023, with the rest resulting from well testing and drilling. Well completion flaring
16 emissions account for most of the CO₂ emissions. Methane emissions from exploration decreased by 98
17 percent from 1990 to 2023, with the largest decreases coming from hydraulically fractured gas well
18 completions without reduced emissions completions (RECs). Methane emissions from exploration
19 decreased 25 percent from 2022 to 2023 due to decreases in emissions from hydraulically fractured well
20 completions (both non-REC with flaring and REC with venting). Methane emissions from exploration
21 were highest from 2006 to 2008. Carbon dioxide emissions from exploration decreased by 94 percent
22 from 1990 to 2023 primarily due to decreases in hydraulically fractured gas well completions. Carbon
23 dioxide emissions from exploration decreased by 2 percent from 2022 to 2023 due to decreases in
24 emissions from hydraulically fractured gas well completions (REC with flaring) and non-hydraulically
25 fractured gas well completions (vented). Carbon dioxide emissions from exploration were highest from
26 2006 to 2008. Nitrous oxide emissions from exploration decreased 96 percent from 1990 to 2023 and
27 decreased 29 percent from 2022 to 2023.

28 *Production (including gathering and boosting).* In the production segment, wells are used to withdraw raw
29 gas from underground formations. Emissions arise from the wells themselves, and from well-site
30 equipment and activities such as pneumatic controllers, tanks and separators, and liquids unloading.
31 Gathering and boosting emission sources are included within the production sector. The gathering and
32 boosting sources include gathering and boosting stations (with multiple emission sources on site) and
33 gathering pipelines. The gathering and boosting stations receive natural gas from production sites and
34 transfer it, via gathering pipelines, to transmission pipelines or processing facilities (custody transfer
35 points are typically used to segregate sources between each segment). Boosting processes include
36 compression, dehydration, and transport of gas to a processing facility or pipeline. Emissions from
37 production (including gathering and boosting) accounted for 50 percent of CH₄ emissions and 26 percent
38 of CO₂ emissions from natural gas systems in 2023. Emissions from gathering and boosting and
39 pneumatic controllers in onshore production accounted for most of the production segment CH₄
40 emissions in 2023. Within gathering and boosting, the largest sources of CH₄ are compressor exhaust slip,
41 compressor venting and leaks, and tanks. Flaring emissions account for most of the CO₂ emissions from
42 production, with the highest emissions coming from flare stacks at gathering stations, miscellaneous
43 onshore production flaring, and tank flaring. Methane emissions from production increased by 23 percent

1 from 1990 to 2023, due primarily to increases in emissions from pneumatic controllers (due to an increase
2 in the number of controllers, particularly in the number of intermittent bleed controllers) and increases in
3 emissions from compressor exhaust slip in gathering and boosting. Methane emissions from production
4 decreased 9 percent from 2022 to 2023 due to decreases in emissions from well pad equipment leaks
5 (compressors) and pneumatic controllers. Carbon dioxide emissions from production increased by
6 approximately a factor of 3.0 from 1990 to 2023 due to increases in emissions at flare stacks in gathering
7 and boosting and miscellaneous onshore production flaring and increased 11 percent from 2022 to 2023
8 due primarily to increases in emissions at flare stacks at gathering and boosting stations and in
9 miscellaneous onshore production flaring and tank venting. Nitrous oxide emissions from production
10 decreased by 4 percent from 1990 to 2023 due to decreases in emissions from dehydrator units at
11 gathering and boosting stations and decreased 56 percent from 2022 to 2023 due to decreases in
12 emissions from flare stacks at gathering and boosting stations.

13 *Processing.* In the processing segment, natural gas liquids and various other constituents from the raw
14 gas are removed, resulting in “pipeline quality” gas, which is injected into the transmission system.
15 Methane emissions from compressors, including compressor seals, are the primary emission source
16 from this stage. Most of the CO₂ emissions come from acid gas removal (AGR) units, which are designed
17 to remove CO₂ from natural gas. Processing plants accounted for 9 percent of CH₄ emissions and 71
18 percent of CO₂ emissions from natural gas systems. Methane emissions from processing decreased by
19 36 percent from 1990 to 2023 as emissions from compressors (leaks and venting) and equipment leaks
20 decreased; and increased 3 percent from 2022 to 2023 due to increased emissions from gas engines.
21 Carbon dioxide emissions from processing decreased by 5 percent from 1990 to 2023, due to a
22 decrease in AGR emissions, and increased 1 percent from 2022 to 2023 due to increased AGR
23 emissions. Nitrous oxide emissions decreased 53 percent from 2022 to 2023 due to decreased
24 emissions from flares at gas processing plants.

25 *Transmission and Storage.* Natural gas transmission involves high pressure, large diameter pipelines
26 that transport gas long distances from field production and processing areas to distribution systems or
27 large volume customers such as power plants or chemical plants. Compressor station facilities are
28 used to move the gas throughout the U.S. transmission system. Leak CH₄ emissions from these
29 compressor stations and venting from pneumatic controllers account for most of the emissions from
30 this stage. Uncombusted compressor engine exhaust and pipeline venting are also sources of CH₄
31 emissions from transmission. Natural gas is also injected and stored in underground formations, or
32 liquefied and stored in above ground tanks, during periods of low demand (e.g., summer), and
33 withdrawn, processed, and distributed during periods of high demand (e.g., winter). Leak and venting
34 emissions from compressors are the primary contributors to CH₄ emissions from storage. Emissions
35 from liquefied natural gas (LNG) stations and terminals are also calculated under the transmission and
36 storage segment. Methane emissions from the transmission and storage segment accounted for
37 approximately 23 percent of methane emissions from natural gas systems, while CO₂ emissions from
38 transmission and storage accounted for 3 percent of the CO₂ emissions from natural gas systems. CH₄
39 emissions from this source decreased by 42 percent from 1990 to 2023 due to reduced pneumatic
40 device and compressor station emissions (including emissions from compressors and leaks) and
41 decreased 6 percent from 2022 to 2023 due to decreased emissions from pipeline venting and
42 transmission compressors. CO₂ emissions from transmission and storage were 6.4 times higher in 2023
43 than in 1990, due to increased emissions from LNG export terminals, and increased by 4 percent from
44 2022 to 2023, due to increased emissions from LNG stations. The quantity of LNG exported from the
45 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 CH₄ and 86 percent of CO₂ emissions from transmission and storage in year 2023. Nitrous oxide emissions from transmission and storage increased by 67 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 CH₄ emissions from natural gas systems and less than 0.1 percent of CO₂ 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 CH₄ and CO₂ emissions from this stage, as have station upgrades at metering and regulating (M&R) stations. Distribution system CH₄ emissions in 2023 were 70 percent lower than 1990 levels and less than 1 percent lower than 2022 emissions. Distribution system CO₂ emissions in 2023 were 70 percent lower than 1990 levels and less than 1 percent lower than 2022 emissions. Annual CO₂ emissions from this segment are less than 0.1 MMT CO₂ 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 CH₄ emissions. Methane emissions from the post-meter segment accounted for approximately 9 percent of emissions from natural gas systems in 2023. Post-meter CH₄ 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. CO₂ emissions from post-meter account for less than 0.01 percent of total CO₂ emissions from natural gas systems.

Total greenhouse gas emissions from the six subcategories within natural gas systems are shown in MMT CO₂ Eq. in Table 3-60. Total CH₄ emissions for these same segments of natural gas systems are shown in MMT CO₂ Eq. (Table 3-61) and kt (Table 3-62). 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 CO₂ Eq. CH₄ is subtracted from production segment emissions, 4.3 MMT CO₂ Eq. CH₄ is subtracted from the transmission and storage segment, and 0.1 MMT CO₂ Eq. CH₄ 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 CH₄ and CO₂ Emissions from Natural Gas Systems.

Table 3-60: Total Greenhouse Gas Emissions (CH₄, CO₂, and N₂O) from Natural Gas Systems (MMT CO₂ 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	68.6	98.2	114.9	105.4	101.6	97.2	89.9
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	38.3
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	251.4	237.0	227.7	216.8	210.5	208.2	199.6

Note: Totals may not sum due to independent rounding.

1 **Table 3-61: CH₄ Emissions from Natural Gas Systems (MMT CO₂ 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	65.3	93.7	103.9	96.2	92.2	88.5	80.3
<i>Onshore Production</i>	40.1	64.7	58.1	53.5	50.1	47.5	40.2
<i>Gathering and Boosting</i>	20.5	26.9	45.3	42.5	42.0	41.0	40.1
<i>Offshore Production</i>	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	37.2
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	219.0	210.6	189.0	180.0	174.7	171.8	162.0

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

3 **Table 3-62: CH₄ Emissions from Natural Gas Systems (kt)**

Segment	1990	2005	2019	2020	2021	2022	2023
Exploration	239	705	75	7	5	6	5
Production	2,333	3,345	3,709	3,435	3,294	3,162	2,869
<i>Onshore Production</i>	1,432	2,312	2,077	1,911	1,791	1,696	1,435
<i>Gathering and Boosting</i>	731	960	1,616	1,519	1,500	1,463	1,431
<i>Offshore Production</i>	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	1,328
Distribution	1,819	1,018	554	553	547	544	544
Post-Meter	290	344	457	464	465	480	494
Total	7,821	7,522	6,748	6,429	6,240	6,135	5,784

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

5 **Table 3-63: CO₂ 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	3.2	4.6	11.0	9.2	9.3	8.6	9.6
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	32.4	26.3	38.7	36.8	35.7	36.4	37.6

6 + Does not exceed 0.05 MMT CO₂ Eq.

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

1 **Table 3-64: CO₂ Emissions from Natural Gas Systems (kt)**

Segment	1990	2005	2019	2020	2021	2022	2023
Exploration	619	2,708	249	97	38	37	36
Production	3,237	4,558	11,004	9,176	9,325	8,640	9,610
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	32,431	26,321	38,701	36,813	35,740	36,402	37,605

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

3 **Table 3-65: N₂O Emissions from Natural Gas Systems (Metric Tons CO₂ Eq.)**

Segment	1990	2005	2019	2020	2021	2022	2023
Exploration	518	1,707	114	46	19	27	19
Production	3,853	5,200	5,101	3,739	3,953	8,374	3,699
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	4,600	10,164	10,865	9,093	8,469	18,216	8,135

4 NO (Not Occurring)

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

6 **Table 3-66: N₂O Emissions from Natural Gas Systems (Metric Tons N₂O)**

Segment	1990	2005	2019	2020	2021	2022	2023
Exploration	2.0	6.4	0.4	0.2	0.1	0.1	0.1
Production	14.5	19.6	19.2	14.1	14.9	31.6	14.0
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	17.4	38.4	41.0	34.3	32.0	68.7	30.7

7 NO (Not Occurring)

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

9 Methodology and Time-Series Consistency

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

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

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

7 *Emission Factors.* Key references for emission factors for CH₄ and CO₂ emissions from the U.S. natural
8 gas industry include a 1996 study published by the Gas Research Institute (GRI) and EPA (GRI/EPA
9 1996), EPA's GHGRP (EPA 2024), and others.

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

20 GHGRP Subpart W data were used to develop CH₄, CO₂, and N₂O emission factors for many sources in
21 the *Inventory*. In the exploration and production segments, GHGRP data were used to develop emission
22 factors used for all years of the time series for well testing, gas well completions and workovers with and
23 without hydraulic fracturing, pneumatic controllers and chemical injection pumps, condensate tanks,
24 liquids unloading, miscellaneous flaring, gathering and boosting pipelines, and certain sources at
25 gathering and boosting stations. In the processing segment, for recent years of the time series, GHGRP
26 data were used to develop emission factors for leaks, compressors, flares, dehydrators, and
27 blowdowns/venting. In the transmission and storage segment, GHGRP data were used to develop
28 factors for all years of the time series for LNG stations and terminals and transmission pipeline
29 blowdowns, and for pneumatic controllers for recent years of the time series.

30 Other data sources used for CH₄ emission factors include Zimmerle et al. (2015) for transmission and
31 storage station leaks and compressors, GTI (2009 and 2019) for commercial and industrial meters,
32 Lamb et al. (2015) for recent years for distribution pipelines and meter/regulator stations, Zimmerle et
33 al. (2019) for gathering and boosting stations, Bureau of Ocean Energy Management (BOEM) reports,
34 and Fischer et al. (2018) and IPCC (2019) for post-meter emissions.

35 For CO₂ emissions from sources in the exploration, production, and processing segments that use
36 emission factors not directly calculated from GHGRP data, data from the 1996 GRI/EPA study and the
37 2001 GTI publication were used to adapt the CH₄ emission factors into related CO₂ emission factors. For
38 sources in the transmission and storage segment that use emission factors not directly calculated from
39 GHGRP data, and for sources in the distribution segment, data from the 1996 GRI/EPA study and a GTI
40 publication (1993) were used to adapt the CH₄ emission factors into non-combustion related CO₂
41 emission factors. CO₂ emissions from post-meter sources (commercial, industrial and vehicles) were
42 estimated using default emission factors from IPCC (2019). Carbon dioxide emissions from post-meter
43 residential sources are included in fossil fuel combustion data.

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

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

4 *Activity Data.* Activity data were taken from various published data sets, as detailed in Annex 3.6. Key
5 activity data sources include data sets developed and maintained by EPA's GHGRP (EPA 2024); Enverus
6 (Enverus 2023); BOEM; Federal Energy Regulatory Commission (FERC) (FERC 2024); EIA; the Natural
7 Gas STAR and Methane Challenge Programs annual data; Oil and Gas Journal; and PHMSA.

8 For a few sources, recent direct activity data are not available. For these sources, either 2022 data were
9 used as a proxy for 2023 data, or a set of industry activity data drivers was developed and used to
10 calculate activity data over the time series. Drivers include statistics on gas production, number of
11 wells, system throughput, miles of various kinds of pipe, and other statistics that characterize the
12 changes in the U.S. natural gas system infrastructure and operations. More information on activity data
13 and drivers is available in Annex 3.6.

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

16 *Calculating Net Emissions.* For most sources, net emissions are calculated directly by applying
17 emission factors to activity data. Emission factors used in net emission approaches reflect technology-
18 specific information and take into account regulatory and voluntary reductions. However, for
19 production, transmission and storage, and distribution, some sources are calculated using potential
20 emission factors, and CH₄ that is not emitted is deducted from the total CH₄ potential estimates. To
21 account for use of such technologies and practices that result in lower emissions but are not reflected
22 in "potential" emission factors, data are collected on both regulatory and voluntary reductions.
23 Regulatory actions addressed using this method include EPA National Emission Standards for
24 Hazardous Air Pollutants (NESHAP) regulations for dehydrator vents. Voluntary reductions included in
25 the *Inventory* are those reported to Natural Gas STAR and Methane Challenge for certain sources.

26 Methodological recalculations were applied to the entire time series to ensure time-series consistency
27 from 1990 through 2023. Available GHGRP data (beginning in 2011) and other recent data sources have
28 improved estimates of emissions from natural gas systems. To develop a consistent time series, for
29 sources with new data, EPA reviewed available information on factors that may have resulted in changes
30 over the time series (e.g., regulations, voluntary actions) and requested stakeholder feedback on trends
31 as well. For most sources, EPA developed annual data for 1993 through 2010 by interpolating activity
32 data or emission factors or both between 1992 and 2011 data points. Information on time-series
33 consistency for sources updated in this year's *Inventory* can be found in the Recalculations Discussion
34 below, with additional detail provided in supporting memos (relevant memos are cited in the
35 Recalculations Discussion). For detailed documentation of methodologies, please see Annex 3.5.

36 The notation key "IE" is used for CO₂ and CH₄ emissions from venting and flaring in common data tables
37 category 1.B.2. Disaggregating flaring and venting estimates across the *Inventory* would involve the
38 application of assumptions and could result in inconsistent reporting and, potentially, decreased
39 transparency. Data availability varies across segments within oil and gas activities systems, and
40 emission factor data available for activities that include flaring can include emissions from multiple
41 sources (flaring, venting and leaks).

Uncertainty – TO BE UPDATED FOR FINAL REPORT

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 CO₂ Uncertainty Estimates (2021 uncertainty memo)*.⁷⁴

EPA used Microsoft Excel's @RISK add-in tool to estimate the 95 percent confidence bound around CH₄ and CO₂ emissions from natural gas systems for the current *Inventory*. For the CH₄ uncertainty analysis, EPA focused on the 17 highest-emitting sources for the year 2022, which together emitted 75 percent of methane from natural gas systems in 2022, and extrapolated the estimated uncertainty for the remaining sources. For the CO₂ uncertainty analysis, EPA focused on the three highest-emitting sources for the year 2022, which together emitted 81 percent of CO₂ from natural gas systems in 2022, and extrapolated the estimated uncertainty for the remaining sources. To estimate uncertainty for N₂O, EPA applied the uncertainty bounds calculated for CO₂. 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 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 2022, using the IPCC methodology. The results of the Approach 2 uncertainty analysis are summarized in Table 3-67. Natural gas systems CH₄ emissions in 2022 were estimated to be between 141.2 and 203.0 MMT CO₂ Eq. at a 95 percent confidence level. Natural gas systems CO₂ emissions in 2022 were estimated to be between 31.9 and 42.1 MMT CO₂ Eq. at a 95 percent confidence level. Natural gas systems N₂O emissions in 2022 were estimated to be between 0.13 and 0.18 MMT CO₂ Eq. at a 95 percent

⁷⁴ See <https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems>.

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 CH₄ and CO₂ 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 3-67: Approach 2 Quantitative Uncertainty Estimates for CH₄ and Non-combustion CO₂ Emissions from Natural Gas Systems (MMT CO₂ Eq. and Percent)

Source	Gas	2022 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	173.1	141.2	203.0	-18%	+17%
Natural Gas Systems	CO ₂	36.5	31.9	42.1	-12%	+15%
Natural Gas Systems	N ₂ O	0.15	0.13	0.18	-12%	+15%

^a Range of emission estimates estimated by applying the 95 percent confidence intervals obtained from the Monte Carlo simulation analysis conducted for the year 2022 CH₄ and CO₂ 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 Note: Totals may not sum due to independent rounding.
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

1 completed reports, and staff review of the reported data. Based on the results of the verification
2 process, the EPA follows up with facilities to resolve mistakes that may have occurred.⁷⁵

3 As in previous years, EPA conducted early engagement and communication with stakeholders on
4 updates prior to public review of the current *Inventory*. EPA held a stakeholder webinar in November
5 2024. EPA released a memo detailing updates under consideration and requesting stakeholder
6 feedback.

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

20 A key challenge in using these types of studies to assess *Inventory* results is having a relevant basis for
21 comparison (e.g., the two data sets should have comparable time frames and geographic coverage, and
22 the independent study should assess data from the *Inventory* and not another data set, such as the
23 Emissions Database for Global Atmospheric Research, or “EDGAR”). In an effort to improve the ability to
24 compare the national-level *Inventory* with measurement results that may be at other spatial and
25 temporal scales, EPA has developed a gridded inventory of U.S. anthropogenic methane emissions with
26 0.1 degree x 0.1 degree spatial resolution, monthly temporal resolution, and detailed scale-dependent
27 error characterization.⁷⁶ The most recent version of the gridded methane inventory is designed to be
28 consistent with the U.S. EPA’s *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2018*
29 estimates for the years 2012 to 2018. The gridded inventory improves efforts to compare results of this
30 *Inventory* with atmospheric studies.

31 Recalculations Discussion

32 EPA received information and data related to the emission estimates through GHGRP reporting and
33 presented information to stakeholders regarding the updates under consideration. In December 2024,
34 EPA released a draft memorandum that discussed changes under consideration and requested
35 stakeholder feedback on those changes.⁷⁷ The memorandum cited in the Recalculations Discussion
36 below is: *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2023: Updates Under*
37 *Consideration to Use New Offshore Data (Offshore Production memo)*.

⁷⁵ See https://www.epa.gov/sites/production/files/2015-07/documents/ghgrp_verification_factsheet.pdf.

⁷⁶ See <https://www.epa.gov/ghgemissions/us-gridded-methane-emissions>.

⁷⁷ Stakeholder materials including draft memoranda for the current (i.e., 1990 to 2023) *Inventory* are available at <https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems>.

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

5 In addition to the updates to the source mentioned above, for certain sources, CH₄ and/or CO₂
 6 emissions changed by greater than 0.05 MMT CO₂ Eq., comparing the previous estimate for 2022 to the
 7 current (recalculated) estimate for 2022. The emissions changes were mostly due to GHGRP data
 8 submission revisions. These sources are discussed below and include pneumatic controllers, chemical
 9 injection pumps, liquids unloading, and offshore production (in the production segment); gathering and
 10 boosting (G&B) dehydrators, pneumatic controllers, blowdowns, and storage tanks; natural gas
 11 processing blowdowns and acid gas removal (AGR); LNG export sources; and residential post-meter.

12 The combined impact of revisions to 2022 natural gas systems CH₄ emissions, compared to the
 13 previous *Inventory*, is a decrease from 173.1 to 171.8 MMT CO₂ Eq. (1.3 MMT CO₂ Eq., or 0.8 percent).
 14 The recalculations resulted in an average increase in the annual CH₄ emission estimates across the
 15 1990 through 2022 time series, compared to the previous *Inventory*, of 0.1 MMT CO₂ Eq., or less than 0.1
 16 percent.

17 The combined impact of revisions to 2022 natural gas systems CO₂ emissions, compared to the
 18 previous *Inventory*, is a decrease from 36.5 MMT to 36.4 MMT (0.1 MMT or 0.2 percent). The
 19 recalculations resulted in an average increase in emission estimates across the 1990 through 2022 time
 20 series, compared to the previous *Inventory*, of less than 0.1 MMT CO₂ Eq., or less than 0.1 percent.

21 The combined impact of revisions to 2022 natural gas systems N₂O emissions, compared to the
 22 previous *Inventory*, is a decrease from 152.0 kt CO₂ Eq. to 18.2 kt CO₂ Eq., or 88 percent. This change for
 23 2022 was due to a correction in the emission factor calculation for production storage tank flaring. The
 24 recalculations resulted in an average decrease in emission estimates across the 1990 through 2022
 25 time series, compared to the previous *Inventory*, of 4.6 kt CO₂ Eq., or 7 percent.

26 In Table 3-68 and Table 3-69 below are categories in natural gas systems with recalculations resulting in
 27 a change of greater than 0.05 MMT CO₂ Eq., comparing the previous estimate for 2022 to the current
 28 (recalculated) estimate for 2022. No changes made to N₂O estimates resulted in a change greater than
 29 0.05 MMT CO₂ Eq. For more information, please see the Recalculations Discussion below.

30 **Table 3-68: Recalculations of CO₂ in Natural Gas Systems (MMT CO₂)**

Segment and Emission Sources with Changes of Greater than 0.05 MMT CO ₂ due to Recalculations	<i>Previous Estimate Year 2022, 2024 Inventory</i>	<i>Current Estimate Year 2022, 2025 Inventory</i>	<i>Current Estimate Year 2023, 2025 Inventory</i>
Exploration	+	+	+
Production	8.6	8.6	9.6
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

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
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	+	+	+
Residential	+	+	+
Total	36.5	36.4	37.6

1 + Does not exceed 0.05 MMT CO₂ Eq.

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

3 Table 3-69: Recalculations of CH₄ in Natural Gas Systems (MMT CO₂ 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	88.5	80.3
Pneumatic Controllers	18.0	19.6	16.2
Chemical Injection Pumps	2.1	2.0	1.7
Liquids Unloading	2.4	2.2	1.4
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
Transmission and Storage	39.6	39.6	37.2
Distribution	+	+	+
Post-Meter	13.4	13.4	13.8
Residential	6.2	5.7	5.8
Total	173.1	171.8	162.0

4 + Does not exceed 0.05 MMT CO₂ Eq.

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

6 Exploration

7 There were no methodological updates for exploration and recalculations resulted in an average
8 increase in CH₄ emissions across the time series of 1 percent and an average increase in calculated CO₂
9 emissions across the time series of 0.5 percent, compared to the previous *Inventory*.

1 Production

2 **Offshore Production in Gulf of America (Methodological Update)**

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

20 As a result of this methodological update, CH₄ emissions estimates for offshore production in the GOA
 21 are on average 76 percent lower for 2019 - 2022 compared to the previous *Inventory*. The 2022 CH₄
 22 emissions estimate is 87 percent lower than in the previous *Inventory*. The update resulted in CO₂
 23 emissions estimates for offshore production in the GOA that are on average 82 percent lower for 2019 -
 24 2022 compared to the previous *Inventory*. The 2022 CO₂ emissions estimate is 94 percent lower than in
 25 the previous *Inventory*. The emission decreases are due to lower emission factors calculated from the
 26 BOEM 2021 dataset compared to the BOEM 2017 dataset. The methodological update did not impact
 27 emissions for years prior to 2019; differences in emissions compared to the previous *Inventory* for years
 28 prior to 2019 are due to changes in underlying activity data (e.g., number of offshore complexes, oil and
 29 gas production).

30 **Table 3-70: GOA Offshore Production Vent and Leak National CH₄ Emissions (Metric**
 31 **Tons CH₄)**

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
<i>Previous Estimate</i>	168,151	71,526	27,136	31,148	21,533	22,712	NA

32 NA (Not Applicable)

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

1 **Table 3-71: GOA Offshore Production Vent and Leak National CO₂ Emissions (Metric**
 2 **Tons CO₂)**

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
<i>Previous Estimate</i>	<i>2,098</i>	<i>840</i>	<i>802</i>	<i>920</i>	<i>638</i>	<i>673</i>	<i>NA</i>

3 NA (Not Applicable)

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

5 ***Chemical Injection Pumps (Recalculation with Updated Data)***

6 Chemical injection pump CH₄ emission estimates resulted in an average decrease of 0.2 percent
 7 across the time series compared to the previous *Inventories*. The estimate for 2022 is 6 percent lower
 8 than the previous *Inventories*. These changes were due to GHGRP submission revisions.

9 **Table 3-72: Chemical Injection Pumps National CH₄ Emissions (Metric Tons CH₄)**

Source	1990	2005	2019	2020	2021	2022	2023
Chemical Injection Pumps	25,587	80,213	111,557	87,149	76,546	72,095	61,822
<i>Previous Estimate</i>	<i>25,587</i>	<i>80,213</i>	<i>111,631</i>	<i>87,227</i>	<i>76,893</i>	<i>76,407</i>	<i>NA</i>

10 NA (Not Applicable)

11 ***Pneumatic Controllers (Recalculation with Updated Data)***

12 Pneumatic controller CH₄ emissions estimates are on average 1.4 percent higher across the time-
 13 series than in the previous *Inventories*. The estimate for 2022 is 9 percent higher than in the previous
 14 *Inventories*. These changes were due to GHGRP submission revisions.

15 **Table 3-73: Pneumatic Controllers National CH₄ Emissions (Metric Tons CH₄)**

Source	1990	2005	2019	2020	2021	2022	2023
Low Bleed Controllers	0	22,992	23,366	20,522	21,093	27,110	22,833
High Bleed Controllers	362,528	488,063	52,617	42,279	41,454	30,726	12,031
Intermittent Bleed Controllers	234,235	569,994	886,605	771,581	750,231	642,522	544,056
Total Emissions	596,763	1,081,049	962,587	834,383	812,778	700,359	578,920
<i>Previous Estimate</i>	<i>589,332</i>	<i>1,067,997</i>	<i>958,943</i>	<i>817,727</i>	<i>747,391</i>	<i>643,721</i>	<i>NA</i>

16 NO (Not Occurring)

17 NA (Not Applicable)

18 ***Liquids Unloading (Recalculation with Updated Data)***

19 Liquids unloading CH₄ emissions estimates decreased by an average of 0.2 percent across the
 20 1990 to 2022 time series compared with the previous *Inventories*. The 2022 estimate decreased by 7
 21 percent compared with the previous *Inventories*. These changes were due to GHGRP submission
 22 revisions.

1 **Table 3-74: Liquids Unloading National CH₄ Emissions (Metric Tons CH₄)**

Source	1990	2005	2019	2020	2021	2022	2023
Liquids Unloading With Plunger Lifts	0	128,636	75,061	51,451	33,896	23,592	16,172
Liquids Unloading Without Plunger Lifts	77,767	198,708	104,346	84,232	65,415	54,718	33,105
Total Emissions	77,767	327,344	179,407	135,683	99,311	78,309	49,277
<i>Previous Estimate</i>	77,767	327,023	179,565	135,707	99,572	84,611	NA

2 NA (Not Applicable)

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

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

5 Gathering and boosting (G&B) station storage tank CH₄ emissions estimates are on average 10
 6 percent lower across the 1990 to 2022 time series than in the previous *Inventory*. The 2022 estimate
 7 is 21 percent lower than in the previous *Inventory*. These changes were due to GHGRP submission
 8 revisions and a revised approach to determine the number of tanks reported under GHGRP.

9 **Table 3-75: G&B Storage Tanks National Emissions (Metric Tons CH₄)**

Source	1990	2005	2019	2020	2021	2022	2023
G&B Storage Tanks	116,335	150,494	293,786	223,609	238,478	244,981	189,262
<i>Previous Estimate</i>	128,572	166,324	297,668	239,291	276,586	310,216	NA

10 NA (Not Applicable)

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

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

13 G&B station blowdown CH₄ emissions estimates are on average 44 percent higher across the 1990 to
 14 2022 time series than in the previous *Inventory*. The 2022 estimate is 13 percent higher than in the
 15 previous *Inventory*. These changes were due to GHGRP submission revisions and a revised approach to
 16 incorporate blowdown emissions reported under GHGRP when facilities use flow meters to determine
 17 emissions.

18 **Table 3-76: G&B Station Blowdowns National Emissions (Metric Tons CH₄)**

Source	1990	2005	2019	2020	2021	2022	2023
G&B Station Blowdowns	29,830	38,589	59,948	51,211	40,462	36,269	32,672
<i>Previous Estimate</i>	20,218	26,155	39,059	40,519	35,161	32,036	NA

19 NA (Not Applicable)

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

21 G&B pneumatic controllers CH₄ emissions estimates are on average 0.2 percent lower across the 1990
 22 to 2022 time series compared with the previous *Inventory*. The emissions estimate for 2022 is 4 percent
 23 lower than in the previous *Inventory*, largely because of a decrease in emissions from high-bleed
 24 pneumatic controllers. These changes were due to GHGRP submission revisions.

1 **Table 3-77: G&B Pneumatic Controllers National Emissions (Metric Tons CH₄)**

Source	1990	2005	2019	2020	2021	2022	2023
High-Bleed Pneumatic Controllers	17,092	22,111	22,644	21,608	19,296	17,342	15,259
Intermittent Bleed Pneumatic Controllers	78,424	101,451	184,679	171,860	156,290	139,715	118,834
Low-Bleed Pneumatic Controllers	2,713	3,509	6,938	6,915	6,524	6,504	5,576
Total Emissions	98,229	127,072	214,261	200,383	182,110	163,562	139,670
<i>Previous Estimate</i>	98,229	127,072	215,725	201,625	184,116	171,000	NA

2 NA (Not Applicable)

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

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

5 G&B dehydrator vent CH₄ emissions estimates are on average 0.2 percent higher across the 1990 to
6 2022 time series compared with the previous *Inventory*. The emissions estimate for 2022 is 7 percent
7 higher than in the previous *Inventory*. These changes were due to GHGRP submission revisions.

8 **Table 3-78: G&B Dehydrator Vent National Emissions (Metric Tons CH₄)**

Source	1990	2005	2019	2020	2021	2022	2023
G&B Dehydrator Vents	35,574	46,020	57,148	52,958	59,738	43,491	37,917
<i>Previous Estimate</i>	35,579	46,026	57,084	52,912	59,836	40,517	NA

9 NA (Not Applicable)

10 **Processing**

11 ***AGR (Recalculation with Updated Data)***

12 Acid gas removal (AGR) CO₂ emission estimates are on average 0.02 percent lower across the time
13 series than in the previous *Inventory*. The CO₂ estimate for 2022 is 0.4 percent lower than in the previous
14 *Inventory*. These changes were due to GHGRP submission revisions.

15 **Table 3-79: Processing Segment AGR National CO₂ Emissions (kt CO₂)**

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

16 NA (Not Applicable)

17 ***Blowdowns (Recalculation with Updated Data)***

18 Processing blowdown CH₄ emissions estimates are on average 0.4 percent lower across the time series
19 than in the previous *Inventory*. The emissions estimate for 2022 is 31 percent lower than in the previous
20 *Inventory*. These changes were due to GHGRP submission revisions and a correction in the emission
21 factor calculation.

1 **Table 3-80: Processing Blowdowns National CH₄ Emissions (Metric Tons CH₄)**

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

2 NA (Not Applicable)

3 **Transmission and Storage**

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

5 LNG export terminal CO₂ emissions estimates are on average 0.3 percent lower across the time series
 6 than in the previous *Inventory*. The 2022 estimate is 6 percent lower than in the previous *Inventory*.
 7 These changes were due to updated data and GHGRP submission revisions.

8 **Table 3-81: LNG Export Terminals National CO₂ Emissions (kt CO₂)**

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
<i>Previous Estimate</i>	0.02	0.02	979	1,767	707	1,005	NA

9 NA (Not Applicable)

10 **Distribution**

11 There were no methodological updates to the distribution segment and recalculations resulted in an
 12 average increase in CH₄ emissions across the time series of less than 0.1 percent and an average
 13 increase in calculated CO₂ emissions across the time series of less than 0.1 percent, compared to the
 14 previous *Inventory*.

15 **Post-Meter**

16 ***Residential Post-Meter (Recalculation with Updated Data)***

17 Residential post-meter emissions are on average less than 0.1 percent higher across the time series
 18 than in the previous *Inventory*. The 2022 estimate is 2 percent higher than in the previous *Inventory*.
 19 These changes were due to updated data.

20 **Table 3-82: Residential Post-Meter National CH₄ Emissions (Metric Tons CH₄)**

Source	1990	2005	2019	2020	2021	2022	2023
Residential Post-Meter	142,755	169,828	190,478	195,696	199,194	202,455	205,717
<i>Previous Estimate</i>	142,755	169,828	190,478	195,696	199,194	199,194	NA

21 NA (Not Applicable)

22 **Planned Improvements**

23 **Planned Improvements for 2025 Inventory**

24 EPA did not update the Enverus data for the public review estimates and will do so for the final version of
 25 the 2025 *Inventory*.

1 EPA continues to seek stakeholder feedback on the draft updates included in this public review draft
2 and may revise the calculations in the *Inventory* based on feedback received. Additional information on
3 the updates and specific requests for stakeholder feedback can be found in the *Offshore Production*
4 memo.

5 **Upcoming Data, and Additional Data that Could Inform the Inventory**

6 EPA will assess new data received by EPA's Greenhouse Gas Reporting Program on an ongoing basis,
7 which may be used to validate or improve existing estimates and assumptions. In December 2024, EPA
8 released a memorandum discussing updates under consideration for a future *Inventory* to incorporate
9 revised GHGRP subpart W emission factors and requested stakeholder feedback (*Inventory of U.S.*
10 *Greenhouse Gas Emissions and Sinks: Updates Under Consideration to Use Revised Subpart W*
11 *Emission Factors*).⁷⁸

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

17 **3.8 Abandoned Oil and Gas Wells (Source** 18 **Categories 1B2a and 1B2b)**

19 The term "abandoned wells", as used in the *Inventory*, encompasses various types of oil and gas wells,
20 including orphaned wells and other non-producing wells:

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

26 The U.S. population of abandoned oil and gas wells (including orphaned wells and other non-producing
27 wells) is around 3.9 million (with around 3.0 million abandoned oil wells and 0.9 million abandoned gas
28 wells). The methods to calculate emissions from abandoned wells involve calculating the total
29 populations of plugged and unplugged abandoned oil and gas wells in the United States and the
30 application of emission factors. An estimate of the number of orphaned wells within this population is
31 not developed as part of the methodology. Wells that are plugged have much lower average emissions
32 than wells that are unplugged (less than 1 kg CH₄ per well per year, versus over 100 kg CH₄ per well per
33 year). Around 43 percent of the abandoned well population in the United States is plugged. This fraction
34 has increased over the *Inventory* time series (from around 22 percent in 1990) as more wells fall under
35 regulations and programs requiring or promoting plugging of abandoned wells. Revised abandoned oil

⁷⁸ The memo is available online: <https://www.epa.gov/ghgemissions/stakeholder-process-natural-gas-and-petroleum-systems-1990-2023-inventory>

1 and gas well counts from Enverus were not available for the public review version of the *Inventory*. This
 2 version of the *Inventory* used 2022 activity data as proxy for 2023 (Enverus 2023).

3 *Abandoned oil wells.* Abandoned oil wells emitted 235 kt CH₄ and 5 kt CO₂ in 2023. Emissions of both
 4 gases increased by 3 percent from 1990, while the total population of abandoned oil wells increased 40
 5 percent.

6 *Abandoned gas wells.* Abandoned gas wells emitted 68 kt CH₄ and 3 kt CO₂ in 2023. Emissions of both
 7 gases increased by 33 percent from 1990, while the total population of abandoned gas wells increased
 8 83 percent.

9 **Table 3-83: CH₄ Emissions from Abandoned Oil and Gas Wells (MMT CO₂ 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

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

11 **Table 3-84: CH₄ 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

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

13 **Table 3-85: CO₂ Emissions from Abandoned Oil and Gas Wells (MMT CO₂)**

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

14 + Does not exceed 0.05 MMT CO₂ Eq.

15 **Table 3-86: CO₂ 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

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

17 Methodology and Time-Series Consistency

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

1 *U.S. Greenhouse Gas Emissions and Sinks 1990-2016: Abandoned Wells in Natural Gas and Petroleum*
2 *Systems (2018 Abandoned Wells Memo).*

3 EPA developed abandoned well CH₄ emission factors using data from Kang et al. (2016) and Townsend-
4 Small et al. (2016). Plugged and unplugged abandoned well CH₄ emission factors were developed at the
5 national-level (using emission data from Townsend-Small et al.) and for the Appalachia region (using
6 emission data from measurements in Pennsylvania and Ohio conducted by Kang et al. and Townsend-
7 Small et al., respectively). The Appalachia region emissions factors were applied to abandoned wells in
8 states in the Appalachian basin region, and the national-level emission factors were applied to
9 abandoned wells in all other states. EPA developed abandoned well CO₂ emission factors using the CH₄
10 emission factors and an assumed ratio of CO₂-to-CH₄ gas content, similar to the approach used to
11 calculate CO₂ emissions for many sources in Petroleum Systems and Natural Gas Systems. For
12 abandoned oil wells, EPA used the Petroleum Systems default production segment associated gas ratio
13 of 0.020 MT CO₂/MT CH₄, which was derived through API TankCalc modeling runs. For abandoned gas
14 wells, EPA used the Natural Gas Systems default production segment CH₄ and CO₂ gas content values
15 (GRI/EPA 1996, GTI 2001) to develop a ratio of 0.044 MT CO₂/MT CH₄. The same respective emission
16 factors are applied for each year of the time series.

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

23 The state-level abandoned well population was then split into plugged and unplugged wells by applying
24 an assumption that all abandoned wells were unplugged in 1950 and using Enverus data to calculate the
25 fraction of plugged abandoned wells in 2023. Linear interpolation was applied between the 1950 value
26 and 2023 value to calculate the plugged fraction for intermediate years. See the memorandum *Inventory*
27 *of U.S. Greenhouse Gas Emissions and Sinks 1990-2016: Abandoned Wells in Natural Gas and*
28 *Petroleum Systems (2018 Abandoned Wells Memo)* for details.⁷⁹

⁷⁹ See <https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems>.

1 Abandoned Oil Wells

2 **Table 3-87: Abandoned Oil Wells Activity Data, CH₄ and CO₂ 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 CH₄ from abandoned oil wells (kt)	227.7	236.4	237.2	237.3	237.2	235.4	235.4
Total CO₂ from abandoned oil wells (kt)	4.6	4.8	4.8	4.8	4.8	4.8	4.8

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

4 Abandoned Gas Wells

5 **Table 3-88: Abandoned Gas Wells Activity Data, CH₄ and CO₂ 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 CH₄ from abandoned gas wells (kt)	51.1	57.6	64.7	66.1	68.7	68.0	68.0
Total CO₂ from abandoned gas wells (kt)	2.2	2.5	2.8	2.9	3.0	3.0	3.0

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

7 **Uncertainty – TO BE UPDATED FOR FINAL REPORT**

8 To characterize uncertainty surrounding estimates of abandoned well emissions, EPA conducted a
 9 quantitative uncertainty analysis using the IPCC Approach 2 methodology (Monte Carlo simulation
 10 technique). See the 2018 Abandoned Wells Memo for details of the uncertainty analysis methods. EPA
 11 used Microsoft Excel's @RISK add-in tool to estimate the 95 percent confidence bound around total
 12 methane emissions from abandoned oil and gas wells in year 2022, then applied the calculated bounds
 13 to both CH₄ and CO₂ emissions estimates for each population. The @RISK add-in provides for the
 14 specification of probability density functions (PDFs) for key variables within a computational structure
 15 that mirrors the calculation of the inventory estimate. EPA used measurement data from the Kang et al.
 16 (2016) and Townsend-Small et al. (2016) studies to characterize the CH₄ emission factor PDFs. For
 17 activity data inputs (e.g., total count of abandoned wells, split between plugged and unplugged), EPA
 18 assigned default uncertainty bounds of ± 10 percent based on expert judgment.

19 The IPCC guidance notes that in using this method, "some uncertainties that are not addressed by
 20 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 3-89 provide the 95 percent confidence bound within which actual emissions from abandoned oil and gas wells are likely to fall for the year 2022, using the recommended IPCC methodology. Abandoned oil well CH₄ emissions in 2022 were estimated to be between 1.1 and 19.7 MMT CO₂ Eq., while abandoned gas well CH₄ emissions were estimated to be between 0.3 and 5.4 MMT CO₂ 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 3-89: Approach 2 Quantitative Uncertainty Estimates for CH₄ and CO₂ Emissions from Petroleum and Natural Gas Systems (MMT CO₂ Eq. and Percent)

Source	Gas	2022 Emission Estimate (MMT CO ₂ Eq.) ^b	Uncertainty Range Relative to Emission Estimate ^a			
			Lower Bound	Upper Bound	Lower Bound (%)	Upper Bound (%)
Abandoned Oil Wells	CH ₄	6.6	1.1	19.7	-83%	+204%
Abandoned Gas Wells	CH ₄	1.9	0.3	5.4	-83%	+204%
Abandoned Oil Wells	CO ₂	0.005	0.001	0.014	-83%	+204%
Abandoned Gas Wells	CO ₂	0.003	0.0005	0.008	-83%	+204%

^a Range of emission estimates estimated by applying the 95 percent confidence intervals obtained from the Monte Carlo simulation analysis conducted for total abandoned oil and gas well CH₄ emissions in year 2022.

^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.

1 Recalculations Discussion

2 Revised abandoned oil and gas well counts from Enverus were not available for the public review version
3 of the *Inventory*. This version of the *Inventory* used 2022 data as proxy for 2023 (Enverus 2023). EPA will
4 update the *Inventory* with revised abandoned oil and gas well counts developed from Enverus data for
5 the final version.

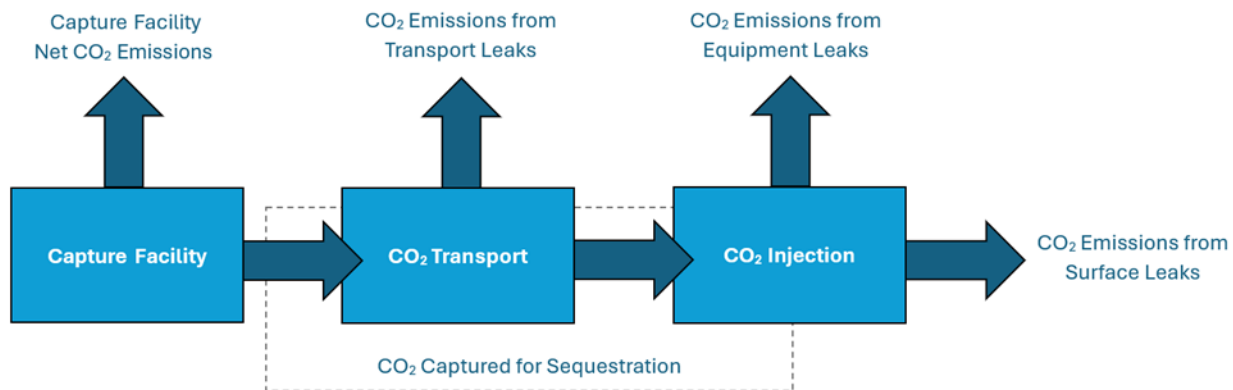
6 Planned Improvements

7 EPA will continue to assess new data and stakeholder feedback on considerations (such as potential
8 use of emission factor data from regions not included in the measurement studies on which current
9 emission factors are based) to improve the abandoned well count estimates and emission factors. In
10 future Inventories, EPA will assess data that become available from Department of Interior and
11 Department of Energy orphan well plugging programs.

12 3.9 CO₂ Transport, Injection, and 13 Geological Storage (Source Category 14 1C)

15 Emissions and reductions from CO₂ capture and sequestration are reported under the IPCC sector in
16 which capture takes place, as per the *2006 IPCC Guidelines for National Greenhouse Gas Inventories*
17 (IPCC 2006). Fugitive emissions from the systems used to transport captured CO₂ from the source to the
18 injection site, fugitive emissions from activities and equipment at the injection site and those from the
19 end containment once the CO₂ is placed in storage are represented as part of CO₂ Transport, Injection,
20 and Geological Storage (TIGS) reporting. Figure 3-18 shows the flow and accounting of CO₂ emissions
21 across the CO₂ TIGS chain. Emissions from TIGS are shown in Table 3-90.

22 **Figure 3-18: Flow of CO₂ Capture and Sequestration**



23
24 Note: The Capture Facility Net CO₂ Emissions are the result of subtracting the amount of CO₂ Captured for Sequestration from
25 the Capture Facility CO₂ Emissions that would have occurred without CO₂ capture.

1 **Table 3-90: Emission from TIGS (kt CO₂)**

	1990	2005	2019	2020	2021	2022	2023
Transport	NO	NO	2	2	2	2	2
Injection	NO	NO	16	13	37	28	30
Storage	NO	NO	0	23	26	23	56
Total	NO	NO	18	39	65	53	88

2 NO (Not Occurring)

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

4 Sequestered CO₂ is allocated across the different possible source categories as shown in Table 3-91.

5 The source categories are based on information from the Suppliers of CO₂ source category of EPA

6 Greenhouse Gas Reporting Program (GHGRP), 40 CFR Part 98, Subpart PP, also referred to as “subpart

7 PP” (EPA 2024a). More information is provided in the Methodology section below.

8 **Table 3-91: Allocation of Sequestered CO₂ for Inventory Adjustment (kt CO₂)**

	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	10,388
Petroleum Refineries	NO	NO	0	0	0	0	0
NG Processing	NO	NO	2,097	1,465	1,835	2,150	3,950
Total (No Adj)	NO	NO	7,813	5,621	5,794	6,774	14,338

9 NO (Not Occurring)

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

11 For the CO₂ sequestered sourced from natural domes, there is no adjustment needed to the Inventory
 12 since it is considered a transfer from one sink to another. For the CO₂ from Natural gas processing and
 13 Petroleum refining there is no need to further adjust the *Inventory* methodology since those emissions
 14 are already netted out in the *Inventory*.

15 For the CO₂ from any other industrial process source the *Inventory* has been adjusted to subtract that
 16 CO₂ capture from the source. This includes CO₂ captured from biogenic sources such as ethanol
 17 facilities. Since fermentation emissions are biogenic CO₂ emissions, they are not included in the
 18 national inventory (these are already included in national totals due to their treatment in the
 19 Agricultural, Forestry and Other Land Use [AFOLU] sector). So, the subtraction of the amount of biogenic

1 CO₂ transferred to long-term storage may result in negative emissions. See Section 4.16 for more
2 information on this.

3 Methodology and Time-Series Consistency

4 The following section describes the methodology used to estimate CO₂ emissions from transport,
5 injection, and storage of CO₂. The allocation approach for determining the source of CO₂ capture for
6 sequestration is also discussed.

7 Fugitive CO₂ from Transport

8 To estimate CO₂ emissions from pipeline transport, EPA used the IPCC Tier 1 default factor for pipelines
9 as provided by the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC 2006). In this
10 approach, the leakage emissions estimates from pipeline transport are assumed to be independent of
11 throughput and are based on distance (length) of pipeline. EPA estimated emissions associated with the
12 entire CO₂ pipeline network in the United States. This could potentially overestimate emissions, since
13 the amount of captured CO₂ subtraction at the source for the most part (except for NG Processing and
14 petroleum refining) is based on CO₂ received for sequestration, which would already account for any
15 pipeline losses. However, since that value is uncertain, and other sources of CO₂ (e.g., from natural
16 domes) are not being counted, using total CO₂ pipeline length to estimate transport emissions was
17 deemed appropriate.

18 The IPCC Tier 1 default fugitive CO₂ emissions rate from pipelines is 0.25-0.28 metric tons CO₂/km
19 pipeline, based on empirical data and analysis. Actual pipeline leakage rates depend on the type and
20 size of equipment installed in the pipeline systems, and are sourced from PHMSA (2024). In 2023, 5,340
21 miles (8,594 km) of CO₂ pipeline were in operation in the United States. This equates to an estimated
22 average leakage of 2,278 metric tons of CO₂ per year. Annual mileage is shown in Table 3-92.

23 **Table 3-92: Pipeline Mileage (Miles)**

	1990	2005	2019	2020	2021	2022	2023
Miles	NO	NO	5,147	5,150	5,339	5,354	5,340

24 NO (Not Occurring)

25 Fugitive CO₂ from Injection and Storage

26 GHGRP reporters provide an estimate of fugitive emissions from CO₂ injection, assumed to be reported
27 under CO₂ equipment leaks as part of the Geological Sequestration of Carbon Dioxide source category
28 of the GHGRP (40 CFR Part 98, Subpart RR, also referred to as “Subpart RR”), as shown in Table 3-93
29 (EPA 2024b). This information was used to estimate national emissions associated with CO₂ injection in
30 the *Inventory*. The GHGRP data include injection related emissions from the equipment between the
31 flow meter used to measure injection quantity and the injection wellhead which would be included in
32 the *Inventory*. Any fugitive CO₂ emission between the capture facility fence line and the injection point
33 would not be captured using this method, but would be captured as part of transport emissions
34 discussed above.

35 GHGRP reporters also provide an estimate of storage and any measured leakage of CO₂ from storage,
36 assumed to be under CO₂ surface leaks in subpart RR reporting as shown in Table 3-93, which has been
37 incorporated into the *Inventory* as well. GHGRP reporters report the annual mass of CO₂ that is emitted

1 by surface leakage as appropriate in accordance with their approved monitoring, reporting, and
 2 verification (MRV) plan.⁸⁰

3 As with transportation emissions, including equipment and surface leakage could potentially
 4 overestimate emissions since the amount of captured CO₂ subtraction at the source for the most part
 5 (except for NG Processing and petroleum refining) is based on CO₂ sequestered, which already
 6 accounts for any equipment or surface losses. However, like for transport emissions, since that value is
 7 uncertain, and other sources of CO₂ (e.g., from natural domes) are not being counted, including
 8 equipment and surface leaks was deemed appropriate.

9 **Table 3-93: Emissions from Injection and Storage (kt CO₂)**

	1990	2005	2019	2020	2021	2022	2023
CO ₂ Injection Leaks	NO	NO	16	13	37	28	30
CO ₂ Storage Leaks	NO	NO	0	23	26	23	56

10 NO (Not Occurring)

11 CO₂ Sequestration and Capture

12 GHGRP reporters provide an estimate of CO₂ sequestered under subpart RR, as shown in Table 3-94.
 13 Subpart RR provides a mechanism for facilities to report the amount of CO₂ sequestered in geologic
 14 formations on an annual basis to EPA. Facilities measure and report data on the amount of CO₂
 15 received, data used to calculate the amount, and the source of the received CO₂ (if known); various
 16 mass balance equation inputs (mass of CO₂ injected, recycled, emitted, produced, equipment leaks,
 17 surface leakage, and entrained CO₂ in produced hydrocarbons), the amount of CO₂ sequestered, data
 18 used to calculate the inputs/amounts, and an annual monitoring report.

19 **Table 3-94: Sequestered CO₂ (kt CO₂)**

	1990	2005	2019	2020	2021	2022	2023
CO ₂ Sequestered	NO	NO	8,332	6,802	6,952	8,030	16,266

20 NO (Not Occurring)

21 CO₂ sequestered is allocated to its source directly if known based on subpart RR. If the source is
 22 unknown or if multiple sources are listed in Subpart RR, CO₂ sequestered is allocated across sources
 23 based on subpart PP data. This mainly applies to splitting between natural domes and industrial
 24 sources, and in particular natural gas processing. For facilities with annual CO₂ sourced from both CO₂
 25 production wells and natural gas processing, CO₂ was split between the two sources based on subpart
 26 PP enhanced oil recovery (EOR) data, as shown in Table 3-95 (EPA 2024a). The kt of CO₂ data is the
 27 amount of CO₂ produced (natural domes) transferred to EOR and the amount of CO₂ captured
 28 (industrial sources) transferred to EOR. Transfer to EOR is used since that is felt to best represent CO₂
 29 supplied for sequestration.

30 Under subpart PP, EPA receives data from facilities with CO₂ production wells (natural CO₂ domes) and
 31 other industrial facilities that extract or capture CO₂ streams. Importers and exporters of bulk CO₂ are
 32 also required to report if total combined imports/exports of CO₂ and other greenhouse gases exceed
 33 25,000 tons CO₂ Eq. per year. Reporters provide information on the mass of CO₂ captured or extracted,

⁸⁰ 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.

1 data used to calculate that amount, and information on the amount of CO₂ that is supplied to various
 2 end use categories. The amount of CO₂ captured by a specific facility is classified as confidential
 3 business information (CBI) under the GHGRP and therefore only aggregated data is available for use
 4 within the Inventory. Note that Subpart PP data does not include captured CO₂ if it is used on-site. Data
 5 is available on the types and number of facilities that capture CO₂ and that was used to determine the
 6 source categories of CO₂ capture as shown in Table 3-91.

7 For facilities with annual CO₂ sourced from CO₂ production wells, natural gas processing, and ethanol
 8 plants, CO₂ was first split between natural domes (CO₂ production wells) and industrial capture (natural
 9 gas processing and ethanol plants) based on Subpart PP EOR data. Then, industrial capture was split
 10 evenly between natural gas processing and ethanol plants.

11 **Table 3-95: Percentage of CO₂ (kt) Supplied to EOR from Different Sources**

	1990	2005	2019	2020	2021	2022	2023
CO₂ Extracted (domes) for EOR							
kt of CO ₂	NO	NO	37,425	25,290	24,987	26,739	25,100
% of Total	NO	NO	72%	72%	71%	73%	74%
CO₂ 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	33,760

12 NO (Not Occurring)

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

14 Based on this methodology, sequestered CO₂ was allocated across the different possible source
 15 categories, as shown in Table 3-91.

16 Uncertainty

17 A quantitative uncertainty analysis was conducted for CO₂ capture and sequestration using the IPCC-
 18 recommended Approach 2 uncertainty estimation methodology. This analysis utilized the Monte Carlo
 19 stochastic simulation software @Risk to estimate the 95 percent confidence bound around total CO₂
 20 emissions.

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

25 The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-96. Total
 26 emissions associated with CCS were estimated to be between 78.0 and 98.1 kt CO₂ Eq. at the 95
 27 percent confidence level. This indicates a range of approximately 12 percent below to 11 percent above
 28 the 2023 emission estimate of 88.1 kt CO₂ Eq.

1 **Table 3-96: Approach 2 Quantitative Uncertainty Estimates for CO₂ Emissions from**
 2 **TIGS (kt CO₂ 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	88.1	78.0	98.1	-12%	11%

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

4 QA/QC and Verification

5 In order to ensure the quality of the CO₂ emission estimates from TIGS, general (IPCC Tier 1) and
 6 category-specific (Tier 2) Quality Assurance/Quality Control (QA/QC) procedures were implemented
 7 consistent with the U.S. Inventory QA/QC plan outlined in Annex 8. The Tier 2 procedures that were
 8 implemented involved checks specifically focusing on the activity data and emission factor sources and
 9 methodology used for estimating CO₂ from TIGS in the United States.

10 More details on the monitoring and QA/QC methods applicable to the GHGRP data used can be found
 11 under the regulation (40 CFR Part 98).⁸¹ EPA verifies annual facility-level GHGRP reports through a multi-
 12 step process (e.g., combination of electronic checks and manual reviews) to identify potential errors
 13 and ensure that data submitted to EPA are accurate, complete, and consistent.⁸² Based on the results of
 14 the verification process, EPA follows up with facilities to resolve mistakes that may have occurred. The
 15 post-submittals checks are consistent with a number of general and category-specific QC procedures,
 16 including range checks, statistical checks, algorithm checks, and year-to-year checks of reported data
 17 and emissions.

18 Recalculation Discussion

19 No recalculations were performed for the current *Inventory*.

20 Planned Improvements

21 EPA updated the GHGRP rules to add a new subpart VV (40 CFR Part 98 Subpart VV). Subpart VV creates
 22 a reporting pathway for EOR operators who use the ISO 27916:2019 standard (ISO standard) to quantify
 23 the CO₂ sequestered as a result of their operations. The ISO standard has requirements similar to the
 24 site-specific monitoring, reporting and verification (MRV) plan required in order to report geologic
 25 sequestration under subpart RR. When EOR facilities start to report using subpart VV facilities, that
 26 would help to update treatment of CO₂ captured for EOR in the *Inventory*. Data on CO₂ sequestered
 27 under subpart VV could be treated in the *Inventory* in the same way as the subpart RR data.

28 EPA also updated the GHGRP rules to add subpart PP data reporting requirements, that if a CO₂ stream
 29 is captured from any facility subject to 40 CFR part 98 as well as supplying to RR or VV facilities , they
 30 must:

⁸¹ See http://www.ecfr.gov/cgi-bin/text-idx?tpl=/ecfrbrowse/Title40/40cfr98_main_02.tpl.

⁸² See https://www.epa.gov/sites/production/files/2015-07/documents/ghgrp_verification_factsheet.pdf.

- 1 1. Report the facility identification number associated with the annual greenhouse gas report for
2 the Subpart PP facility;
- 3 2. Report each facility identification number associated with the annual greenhouse gas reports
4 for each Subpart RR or VV facility to which CO₂ is transferred; and
- 5 3. Report the annual quantity of CO₂ in metric tons that is transferred to each Subpart RR or VV
6 facility.

7 This provides a more direct link between carbon capture and sequestration in terms of *Inventory*
8 adjustments. This would include CO₂ captured at direct air capture (DAC) facilities in the future. To
9 prevent double counting, the updates also clarify that wells reported under subpart RR or VV should not
10 also be counted under Subpart UU.

11 Furthermore, there could be additional existing GHGRP data available that could provide more input to
12 refine the allocation process. For example, subpart PP reporters track and report biogenic and fossil CO₂
13 separately. That information could be used to help allocate CO₂ from the different capture sources to
14 end uses based on assumptions about the biogenic content of captured CO₂. This data has not yet been
15 incorporated but could be used to help allocate capture and sequestration in the future.

16 Currently, there are no data included in this memo regarding CO₂ sequestered in years prior to 2010.
17 Alternate data sources could be explored, including reported quantities from the Regional Carbon
18 Sequestration Partnerships (RCSPs). Data would need to be available on an annual basis to consider for
19 conclusion.

20 Other possible updates include the treatment of exported CO₂. Exported CO₂ is currently accounted for
21 by adjusting down the amount of fuel combustion to net out emission results. Exported CO₂ could be
22 more explicitly accounted for in the *Inventory* through reporting CO₂ capture from the energy use
23 industrial sector and reporting the quantity of CO₂ export as part of the CO₂ TIGS accounting.

24 3.10 International Bunker Fuels (Source 25 Category 1: Memo Items)

26 Emissions resulting from the combustion of fuels used for international transport activities, termed
27 international bunker fuels, are not included in national emission totals, but are reported separately
28 based upon location of fuel sales. The decision to report emissions from international bunker fuels
29 separately, instead of allocating them to a particular country, reflect the IPCC methodological guidance,
30 including IPCC (2006), in which countries are requested to report emissions from ships or aircraft that
31 depart from their ports with fuel purchased within national boundaries and are engaged in international
32 transport separately from national totals (IPCC 2006).

33 Two transport modes are addressed under the IPCC definition of international bunker fuels: aviation and
34 marine.⁸³ Greenhouse gases emitted from the combustion of international bunker fuels, like other fossil

⁸³ Most emission related international aviation and marine regulations are under the rubric of the International Civil Aviation Organization (ICAO) or the International Maritime Organization (IMO), which develop international codes, recommendations, and conventions, such as the International Convention of the Prevention of Pollution from Ships (MARPOL).

1 fuels, include CO₂, CH₄ and N₂O for marine transport modes, and CO₂ and N₂O for aviation transport
2 modes. Emissions from ground transport activities—by road vehicles and trains—even when crossing
3 international borders are allocated to the country where the fuel was loaded into the vehicle and,
4 therefore, are not counted as bunker fuel emissions.

5 The *2006 IPCC Guidelines* distinguish between three different modes of air traffic: civil aviation, military
6 aviation, and general aviation. Civil aviation comprises aircraft used for the commercial transport of
7 passengers and freight, military aviation comprises aircraft under the control of national armed forces,
8 and general aviation applies to recreational and small corporate aircraft. The *2006 IPCC Guidelines*
9 further define international bunker fuel use from civil aviation as the fuel combusted for civil (e.g.,
10 commercial) aviation purposes by aircraft arriving or departing on international flight segments.
11 However, as mentioned above, and in keeping with the *2006 IPCC Guidelines*, only the fuel purchased in
12 the United States and used by aircraft taking-off (i.e., departing) from the United States are reported
13 here. The standard fuel used for civil and military aviation is kerosene-type jet fuel, while the typical fuel
14 used for general aviation is aviation gasoline.⁸⁴

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

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

28 Overall, aggregate greenhouse gas emissions in 2023 from the combustion of international bunker fuels
29 from both aviation and marine activities were 97.2 MMT CO₂ Eq., or 7.1 percent below emissions in 1990
30 (see Table 3-97 and Table 3-98). Emissions from international flights and international shipping voyages
31 departing from the United States have increased by 74.4 percent and decreased by 54.6 percent,
32 respectively, since 1990. The majority of these emissions were in the form of CO₂; however, small
33 amounts of CH₄ (from marine transport modes) and N₂O were also emitted.

34 For the Public Review, 2023 marine bunker fuel data was available, however aviation and military bunker
35 fuel data were not available and were proxied based on 2022 values. Results will be updated for the
36 Final Report.

⁸⁴ Naphtha-type jet fuel was used in the past by the military in turbojet and turboprop aircraft engines.

1 **Table 3-97: CO₂, CH₄, and N₂O Emissions from International Bunker Fuels (MMT CO₂**
 2 **Eq.)**

Gas/Mode	1990	2005	2019	2020	2021	2022	2023
CO₂	103.6	113.3	113.6	69.6	80.2	98.2	96.4
Aviation	38.2	60.2	78.3	39.8	50.8	66.6	66.6
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	3.1
Marine	65.4	53.1	35.4	29.9	29.4	31.6	29.7
CH₄	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
N₂O	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	97.2

3 NO (Not Occurring)

4 Notes: Totals may not sum due to independent rounding. Includes aircraft cruise altitude emissions. Aviation and military bunker
 5 fuel data were not available and were proxied based on 2022 values. Results will be updated for the Final Report.

6 **Table 3-98: CO₂, CH₄, and N₂O Emissions from International Bunker Fuels (kt)**

Gas/Mode	1990	2005	2019	2020	2021	2022	2023
CO₂	103,634	113,328	113,632	69,638	80,180	98,241	96,362
Aviation	38,205	60,221	78,280	39,781	50,812	66,646	66,646
Marine	65,429	53,107	35,351	29,857	29,369	31,595	29,716
CH₄	7	5	4	3	3	3	3
Aviation	NO	NO	NO	NO	NO	NO	NO
Marine	7	5	4	3	3	3	3
N₂O	3	3	3	2	2	3	3
Aviation	1	2	2	1	2	2	2
Marine	2	1	1	1	1	1	1

7 NO (Not Occurring)

8 Notes: Totals may not sum due to independent rounding. Includes aircraft cruise altitude emissions. Aviation and military bunker
 9 fuel data were not available and were proxied based on 2022 values. Results will be updated for the Final Report.

10 Methodology and Time-Series Consistency

11 Emissions of CO₂ were for the most part estimated by applying carbon content and fraction oxidized
 12 factors to fuel consumption activity data. This approach is analogous to that described under Section
 13 3.1. Carbon content and fraction oxidized factors for jet fuel (except for commercial aviation as per
 14 below), distillate fuel oil, and residual fuel oil are the same as used for CO₂ from Fossil Fuel Combustion
 15 and are presented in Annex 2.1, Annex 2.2, and Annex 3.8 of this *Inventory*. Density conversions were
 16 taken from ASTM (1989) and USAF (1998). Heat content for distillate fuel oil and residual fuel oil were
 17 taken from EIA (2024) and USAF (1998), and heat content for jet fuel was taken from EIA (2024). See
 18 below for details on how emission estimates for commercial aviation were determined.

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

4 Emission estimates for CH₄ and N₂O were calculated by multiplying emission factors by measures of
5 fuel consumption by fuel type and mode. Emission factors used in the calculations of CH₄ and N₂O
6 emissions were obtained from the *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997), which
7 is also referenced in the *2006 IPCC Guidelines* (IPCC 2006). For aircraft emissions, the following value,
8 in units of grams of pollutant per kilogram of fuel consumed (g/kg), was employed: 0.1 for N₂O (IPCC
9 2006). For marine vessels consuming either distillate diesel or residual fuel oil the following values
10 (g/MJ), were employed: 0.315 for CH₄ and 0.08 for N₂O. Activity data for aviation included solely jet fuel
11 consumption statistics, while the marine mode included both distillate diesel and residual fuel oil.

12 Activity data on domestic and international aircraft fuel consumption were developed by the U.S.
13 Federal Aviation Administration (FAA) using radar-informed data from the FAA Enhanced Traffic
14 Management System (ETMS) for 1990 and 2000 through 2023 as modeled with the Aviation
15 Environmental Design Tool (AEDT). This bottom-up approach is built from modeling dynamic aircraft
16 performance for each flight occurring within an individual calendar year. The analysis incorporates data
17 on the aircraft type, date, flight identifier, departure time, arrival time, departure airport, arrival airport,
18 ground delay at each airport, and real-world flight trajectories. To generate results for a given flight within
19 AEDT, the radar-informed aircraft data is correlated with engine and aircraft performance data to
20 calculate fuel burn and exhaust emissions. Information on exhaust emissions for in-production aircraft
21 engines comes from the International Civil Aviation Organization (ICAO) Aircraft Engine Emissions
22 Databank (EDB). This bottom-up approach is in accordance with the Tier 3B method from the *2006 IPCC*
23 *Guidelines* (IPCC 2006).

24 International aviation CO₂ estimates for 1990 and 2000 through 2023 were obtained directly from FAA's
25 AEDT model (FAA 2024). The radar-informed method that was used to estimate CO₂ emissions for
26 commercial aircraft for 1990 and 2000 through 2023 was not possible for 1991 through 1999 because
27 the radar dataset was not available for years prior to 2000. FAA developed Official Airline Guide (OAG)
28 schedule-informed inventories modeled with AEDT and great circle trajectories for 1990, 2000, and
29 2010. Because fuel consumption and CO₂ emission estimates for years 1991 through 1999 are
30 unavailable, consumption estimates for these years were calculated using fuel consumption estimates
31 from the Bureau of Transportation Statistics (DOT 1991 through 2013), adjusted based on 2000 through
32 2005 data. See Annex 3.3 for more information on the methodology for estimating emissions from
33 commercial aircraft jet fuel consumption.

34 Data on U.S. Department of Defense (DoD) aviation bunker fuels and total jet fuel consumed by the U.S.
35 military was supplied by the Office of the Under Secretary of Defense (Installations and Environment),
36 DoD. Estimates of the percentage of each Service's total operations that were international operations
37 were developed by DoD. Military aviation bunkers included international operations, operations
38 conducted from naval vessels at sea, and operations conducted from U.S. installations principally over
39 international water in direct support of military operations at sea. Military aviation bunker fuel emissions
40 were estimated using military fuel and operations data synthesized from unpublished data from DoD's
41 Defense Logistics Agency Energy (DLA Energy 2023). Together, the data allow the quantity of fuel used in
42 military international operations to be estimated. Densities for each jet fuel type were obtained from a
43 report from the U.S. Air Force (USAF 1998). Final jet fuel consumption estimates are presented in Table .
44 See Annex 3.8 for additional discussion of military data.

1 **Table 3-99: 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	44
Total	542	854	1,112	564	721	946	946

2 Note: Totals may not sum due to independent rounding. Aviation and military bunker fuel data were not available and were
 3 proxied based on 2022 values. Results will be updated for the Final Report.

4 In order to quantify the civilian international component of marine bunker fuels, activity data on
 5 distillate diesel and residual fuel oil consumption by cargo or passenger carrying marine vessels
 6 departing from U.S. ports were collected for individual shipping agents on a monthly basis by the U.S.
 7 Customs and Border Protection. This information was then reported in unpublished data collected by
 8 the Foreign Trade Division of the U.S. Department of Commerce’s Bureau of the Census (DOC 1991
 9 through 2023) for 1990 through 2001, 2007 through 2023, and the Department of Homeland Security’s
 10 Bunker Report for 2003 through 2006 (DHS 2008). Fuel consumption data for 2002 was interpolated due
 11 to inconsistencies in reported fuel consumption data. Activity data on distillate diesel consumption by
 12 military vessels departing from U.S. ports were provided by DLA Energy (2023). The total amount of fuel
 13 provided to naval vessels was reduced by 21 percent to account for fuel used while the vessels were not
 14 underway (i.e., in port). Data on the percentage of steaming hours underway versus not underway were
 15 provided by the U.S. Navy. These fuel consumption estimates are presented in Table .

16 **Table 3-100: 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	263
Total	5,920	4,796	3,229	2,721	2,674	2,870	2,702

17 Note: Totals may not sum due to independent rounding. Aviation and military bunker fuel data were not available and were
 18 proxied based on 2022 values. Results will be updated for the Final Report.

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

21 **Uncertainty – TO BE UPDATED FOR FINAL REPORT**

22 Emission estimates related to the consumption of international bunker fuels are subject to the same
 23 uncertainties as those from domestic aviation and marine mobile combustion emissions; however,
 24 additional uncertainties result from the difficulty in collecting accurate fuel consumption activity data
 25 for international transport activities separate from domestic transport activities.⁸⁵ For example, smaller
 26 aircraft on shorter routes often carry sufficient fuel to complete several flight segments without refueling
 27 in order to minimize time spent at the airport gate or take advantage of lower fuel prices at particular
 28 airports. This practice, called tankering, when done on international flights, complicates the use of fuel
 29 sales data for estimating bunker fuel emissions. Tankering is less common with the type of large, long-
 30 range aircraft that make many international flights from the United States, however. Similar practices
 31 occur in the marine shipping industry where fuel costs represent a significant portion of overall

⁸⁵ See uncertainty discussions under section 3.1 CO₂ from Fossil Fuel Combustion.

1 operating costs and fuel prices vary from port to port, leading to some tankering from ports with low fuel
2 costs.

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

8 Additionally, there are uncertainties in historical aircraft operations and training activity data. Estimates
9 for the quantity of fuel actually used in Navy and Air Force flying activities reported as bunker fuel
10 emissions had to be estimated based on a combination of available data and expert judgment.
11 Estimates of marine bunker fuel emissions were based on Navy vessel steaming hour data, which
12 reports fuel used while underway and fuel used while not underway. This approach does not capture
13 some voyages that would be classified as domestic for a commercial vessel. Conversely, emissions
14 from fuel used while not underway preceding an international voyage are reported as domestic rather
15 than international as would be done for a commercial vessel. There is uncertainty associated with
16 ground fuel estimates for 1997 through 2023, including estimates for the quantity of jet fuel allocated to
17 ground transportation. Small fuel quantities may have been used in vehicles or equipment other than
18 that which was assumed for each fuel type.

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

28 Although aggregate fuel consumption data have been used to estimate emissions from aviation, the
29 recommended method for estimating emissions of gases other than CO₂ in the *2006 IPCC Guidelines*
30 (IPCC 2006) is to use data by specific aircraft type, number of individual flights and, ideally, movement
31 data to better differentiate between domestic and international aviation and to facilitate estimating the
32 effects of changes in technologies. The IPCC also recommends that cruise altitude emissions be
33 estimated separately using fuel consumption data, while landing and take-off (LTO) cycle data be used
34 to estimate near-ground level emissions of gases other than CO₂.⁸⁶

⁸⁶ 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.

1 There is also concern regarding the reliability of the existing DOC (1991 through 2023) data on marine
2 vessel fuel consumption reported at U.S. customs stations due to the significant degree of inter-annual
3 variation.

4 QA/QC and Verification

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

12 Recalculations Discussion

13 No recalculations were performed for the current *Inventory*.

14 Planned Improvements

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

23 A longer-term effort is underway to consider the feasibility of including data from a broader range of
24 domestic and international sources for bunker fuels. Potential sources include the IMO greenhouse gas
25 emission inventory, data from the U.S. Coast Guard on vehicle operation currently used in criteria
26 pollutant modeling, data from the International Energy Agency (IEA), relevant updated FAA models to
27 improve aviation bunker fuel estimates, and researching newly available marine bunker data.

28 3.11 Biomass and Biofuels Consumption 29 (Source Category 1A)

30 The combustion of biomass—such as wood, charcoal, the biogenic portions of MSW, and wood waste
31 and biofuels such as ethanol, biogas, and biodiesel—generates CO₂ in addition to CH₄ and N₂O already
32 covered in this chapter. In line with the IPCC guidelines, CO₂ emissions from biomass and biofuel
33 combustion have been estimated separately from fossil fuel CO₂ emissions and are not directly
34 included in the energy sector contributions to U.S. totals. In accordance with IPCC methodological
35 guidelines, any such emissions are calculated by accounting for net carbon fluxes from changes in

1 biogenic carbon reservoirs in wooded or crop lands. For a more complete description of this
 2 methodological approach, see the Land Use, Land-Use Change, and Forestry chapter (Chapter 6),
 3 which accounts for the contribution of any resulting CO₂ emissions to U.S. totals within the Land Use,
 4 Land-Use Change, and Forestry sector's approach.

5 Therefore, CO₂ emissions from biomass and biofuel consumption are not included specifically in
 6 summing energy sector totals. However, they are presented here for informational purposes and to
 7 provide detail on biomass and biofuels consumption.

8 In 2023, total CO₂ emissions from the burning of woody biomass in the industrial, residential,
 9 commercial, and electric power sectors were approximately 187.7 MMT CO₂ Eq. (187,690 kt) (see Table
 10 3-101 and Table 3-102). As the largest consumer of woody biomass, the industrial sector was
 11 responsible for 61.8 percent of the CO₂ emissions from this source. The residential sector was the
 12 second largest emitter, constituting 24.7 percent of the total, while the electric power and commercial
 13 sectors accounted for the remainder.

14 **Table 3-101: CO₂ Emissions from Wood Consumption by End-Use Sector (MMT CO₂**
 15 **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

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

17 **Table 3-102: CO₂ 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

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

19 Carbon dioxide emissions from combustion of the biogenic components of MSW by the electric power
 20 sector were an estimated 14.9 MMT CO₂ (14,864 kt) in 2023. Emissions across the time series are shown
 21 in Table 3-103 and Table 3-104. As discussed in Section 3.3, MSW is combusted to produce electricity
 22 and the CO₂ emissions from the fossil portion of the MSW (e.g., plastics, textiles, etc.) are included in
 23 the energy sector FFC estimates. The MSW also includes biogenic components (e.g., food waste, yard
 24 trimmings, natural fibers) and the CO₂ emissions associated with that biogenic portion is included here.

25 **Table 3-103: CO₂ Emissions from Biogenic Components of MSW (MMT CO₂ 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	14.9

1 **Table 3-104: CO₂ 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	14,864

2 The transportation sector is responsible for most of the fuel ethanol consumption in the United States.
 3 Ethanol used for fuel is currently produced primarily from corn grown in the Midwest, but it can be
 4 produced from a variety of biomass feedstocks. Most ethanol for transportation use is blended with
 5 gasoline to create a 90 percent gasoline, 10 percent by volume ethanol blend known as E-10 or gasohol.

6 In 2023, the United States transportation sector consumed an estimated 1,116.4 trillion Btu of ethanol
 7 (95 percent of total), and as a result, produced approximately 76.4 MMT CO₂ Eq. (76,427 kt) (see Table
 8 3-105 and Table 3-106) of CO₂ emissions. Smaller quantities of ethanol were also used in the industrial
 9 and commercial sectors. Ethanol fuel production and consumption has grown significantly since 1990
 10 due to the favorable economics of blending ethanol into gasoline and federal policies that have
 11 encouraged use of renewable fuels.

12 **Table 3-105: CO₂ Emissions from Ethanol Consumption (MMT CO₂ 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

13 ^a See Annex 3.2, Table A-75 for additional information on transportation consumption of these fuels.
 14 Note: Totals may not sum due to independent rounding.

15 **Table 3-106: CO₂ 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

16 ^a See Annex 3.2, Table A-75 for additional information on transportation consumption of these fuels.
 17 Note: Totals may not sum due to independent rounding.

18 The transportation sector is assumed to be responsible for all of the biodiesel consumption in the
 19 United States (EIA 2024a). Biodiesel is currently produced primarily from soybean oil, but it can be
 20 produced from a variety of biomass feedstocks including waste oils, fats, and greases. Biodiesel for
 21 transportation use appears in low-level blends (less than 5 percent) with diesel fuel, high-level blends
 22 (between 6 and 20 percent) with diesel fuel, and 100 percent biodiesel (EIA 2024b).

23 In 2023, the United States consumed an estimated 246.3 trillion Btu of biodiesel, and as a result,
 24 produced approximately 18.2 MMT CO₂ Eq. (18,185 kt) (see Table 3-107 and Table 3-108) of CO₂
 25 emissions. Biodiesel production and consumption has grown significantly since 2001 due to the
 26 favorable economics of blending biodiesel into diesel and federal policies that have encouraged use of
 27 renewable fuels (EIA 2024b). There was no measured biodiesel consumption prior to 2001 EIA (2024a).

1 **Table 3-107: CO₂ Emissions from Biodiesel Consumption (MMT CO₂ 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

2 NO (Not Occurring)

3 ^a See Annex 3.2, Table A-75 for additional information on transportation consumption of these fuels.

4 **Table 3-108: CO₂ 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

5 NO (Not Occurring)

6 ^a See Annex 3.2, Table A-75 for additional information on transportation consumption of these fuels.

7 Methodology and Time-Series Consistency

8 Woody biomass emissions were estimated by applying two gross heat contents from EIA (Lindstrom
9 2006) to U.S. consumption data (EIA 2024a) (see Table 3-110), provided in energy units for the industrial,
10 residential, commercial, and electric power sectors. One heat content (16.95 MMBtu/MT wood and
11 wood waste) was applied to the industrial sector’s consumption, while the other heat content (15.43
12 MMBtu/MT wood and wood waste) was applied to the consumption data for the other sectors. An EIA
13 emission factor of 0.434 MT C/MT wood (Lindstrom 2006) was then applied to the resulting quantities of
14 woody biomass to obtain CO₂ emission estimates. The woody biomass is assumed to contain black
15 liquor and other wood wastes, have a moisture content of 12 percent, and undergo complete
16 combustion to be converted into CO₂.

17 Data for total waste incinerated, excluding tires, from 1990 to 2023 was derived following the methodology
18 described in Section 3.3. Biogenic CO₂ emissions associated with MSW combustion were obtained from
19 EPA’s GHGRP FLIGHT data for MSW combustion sources (EPA 2023). Dividing biogenic CO₂ emissions
20 from GHGRP FLIGHT data for MSW combustors by estimated MSW tonnage combusted yielded an annual
21 biogenic CO₂ emission factor. This approach follows the same approach used to develop the fossil CO₂
22 emissions from MSW combustion as discussed in Section 3.3. As this data was only available following
23 2011, all years prior use an average of the emission factors from 2011 through 2015.

24 Biogenic CO₂ emissions from MSW combustion were calculated by multiplying the annual tonnage
25 estimates, excluding tires, by the calculated emissions factor. Calculated biogenic CO₂ emission factors
26 are shown in Table 3-109.

27 **Table 3-109: Calculated Biogenic CO₂ Content per Ton Waste (kg CO₂/Short Ton**
28 **Combusted)**

End-Use Sector	1990	2005	2019	2020	2021	2022	2023
CO ₂ Emission Factors	556	556	558	566	550	564	564

29 The amount of ethanol allocated across the transportation, industrial, and commercial sectors was
30 based on the sector allocations of ethanol-blended motor gasoline. The sector allocations of ethanol-
31 blended motor gasoline were determined using a bottom-up analysis conducted by EPA, as described in
32 the Methodology section of Fossil Fuel Combustion. Total U.S. ethanol consumption from EIA (2024a)
33 was allocated to individual sectors using the same sector allocations as ethanol-blended motor
34 gasoline. The emissions from ethanol consumption were calculated by applying an emission factor of

1 18.67 MMT C/Qbtu (EPA 2010) to adjusted ethanol consumption estimates (see Table 3-111). The
 2 emissions from biodiesel consumption were calculated by applying an emission factor of 20.1 MMT
 3 C/Qbtu (EPA 2010) to U.S. biodiesel consumption estimates that were provided in energy units (EIA
 4 2024a) (see Table 3-112).⁸⁷

5 **Table 3-110: 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

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

7 **Table 3-111: 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

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

9 **Table 3-112: 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

10 NO (Not Occurring)

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

13 Uncertainty

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

18 There are uncertainties in ethanol consumption, biodiesel consumption, woody biomass consumption,
 19 and CO₂ emissions from waste incineration. It is assumed that the biodiesel and ethanol reported is 100
 20 percent biodiesel rather than a blend. A normal distribution was assumed for all ethanol consumption,
 21 wood consumption, and MSW input variables, while a uniform distribution was assumed for the

⁸⁷ CO₂ 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.

1 biodiesel emission factor. For these variables, the uncertainty ranges were assigned to the input
 2 variables based on IPCC default uncertainty estimates (IPCC 2006) and expert opinion.

3 The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-96. Biomass
 4 and biofuel combustion CO₂ emissions in 2023 were estimated to be between 273.0 and 336.4 MMT CO₂
 5 Eq. at a 95 percent confidence level. This indicates a range of 9 percent below to 12 percent above the
 6 2023 emission estimate of 301.5 MMT CO₂ Eq.

7 **Table 3-113: Approach 2 Quantitative Uncertainty Estimates for CO₂ Emissions from**
 8 **Biomass and Biofuel Combustion (MMT CO₂ 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	301.5	273.0	336.4	-9%	12%

9 **Recalculations Discussion**

10 EIA (2024a) updated electricity statistics which affected commercial sector wood consumption for the
 11 years 2014 through 2022. This caused CO₂ emissions from commercial wood to decrease by an annual
 12 average of 0.9 MMT CO₂ Eq. (11 percent) for the years 2014 and 2022, compared to estimates in the
 13 previous *Inventory*.

14 EIA (2024a) also updated ethanol consumed by all sectors in 2022, which caused CO₂ emissions from
 15 industrial ethanol to decrease by 0.13 MMT CO₂ Eq. (6.7 percent), CO₂ emissions from transportation
 16 ethanol to decrease by less than 0.5 MMT CO₂ Eq. (less than 0.05 percent), and CO₂ emissions from
 17 commercial ethanol to increase by 0.13 MMT CO₂ Eq. (4.7 percent), compared to the previous *Inventory*.

18 **Planned Improvements**

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

21 Currently, emission estimates from biomass and biomass-based fuels included in this *Inventory* are
 22 limited to woody biomass, biogenic components of MSW, ethanol, and biodiesel. Additional forms of
 23 biomass-based fuel consumption include biogas, renewable diesel and other biofuels. EPA will
 24 investigate additional forms of biomass-based fuel consumption, research the availability of relevant
 25 emissions factors, and integrate these into the *Inventory* as feasible. EPA will examine EIA data on
 26 biogas and other biofuels to see if these fuel types can be included in future Inventories. EIA (2024a)
 27 natural gas data already deducts biogas used in the natural gas supply, so no adjustments are needed to
 28 the natural gas fuel consumption data to account for biogas. Distillate fuel statistics are adjusted in this
 29 *Inventory* to remove renewable diesel fuels as well as biodiesel.

30 The availability of facility-level combustion emissions through EPA’s GHGRP will be examined to help
 31 better characterize the industrial sector’s energy consumption in the United States and further classify
 32 woody biomass consumption by business establishments according to industrial economic activity
 33 type. Most methodologies used in EPA’s GHGRP are consistent with IPCC, although for EPA’s GHGRP,
 34 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 CO₂ 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 CO₂ 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.⁸⁸

Lastly, the CO₂ 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 – TO BE UPDATED FOR FINAL REPORT

In addition to the main greenhouse gases addressed above, energy-related activities are also sources of greenhouse gas precursors. This section summarizes information should be provided on precursor emissions, which include carbon monoxide (CO), nitrogen oxides (NO_x), non-methane volatile organic compounds (NMVOCs), and sulfur dioxide (SO₂). 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, and SO₂ from energy-related activities from 1990 to 2022 are reported in Table 3-114.

Table 3-114: NO_x, CO, NMVOC, and SO₂ Emissions from Energy-Related Activities (kt)

Gas/Activity	1990	2005	2018	2019	2020	2021	2022
NO_x	21,804	18,196	6,812	6,503	5,630	5,570	5,225
Fossil Fuel Combustion	21,678	18,188	6,804	6,496	5,624	5,563	5,218
<i>Transportation^a</i>	12,132	12,628	4,486	4,322	3,618	3,546	3,228
<i>Industrial</i>	2,475	1,486	820	800	751	721	721
<i>Electric Power Sector</i>	6,045	3,440	1,025	898	762	807	781
<i>Commercial</i>	451	288	186	187	193	189	188
<i>Residential</i>	575	346	288	290	300	300	300
Petroleum and Natural Gas Systems	127	8	7	7	7	6	6
<i>International Bunker Fuels</i>	1,953	1,699	1,456	1,280	977	1,008	1,132
CO	124,584	63,891	30,237	29,854	27,897	28,283	27,607
Fossil Fuel Combustion	124,353	63,686	30,050	29,660	27,703	28,098	27,426

⁸⁸ See http://www.ipcc-nggip.iges.or.jp/public/tb/TFI_Technical_Bulletin_1.pdf.

Transportation ^a	119,478	59,540	26,024	25,621	23,546	23,912	23,235
Residential	3,620	2,393	2,751	2,860	2,968	2,950	2,950
Industrial	705	976	620	600	670	658	655
Electric Power Sector	329	582	505	428	362	423	428
Commercial	220	195	151	151	157	154	158
Petroleum and Natural Gas Systems	232	205	186	194	194	185	181
International Bunker Fuels	102	131	158	150	83	101	128
NMVOCs	12,269	8,081	5,050	4,987	4,822	5,167	5,045
Fossil Fuel Combustion	11,793	6,079	2,632	2,593	2,391	2,454	2,329
Transportation ^a	10,932	5,608	2,127	2,072	1,846	1,912	1,786
Residential	693	322	382	397	431	429	429
Commercial	9	18	14	14	14	14	14
Industrial	117	87	80	81	74	73	74
Electric Power Sector	43	44	30	29	26	27	27
Petroleum and Natural Gas Systems	476	2,002	2,418	2,394	2,431	2,713	2,716
International Bunker Fuels	57	54	50	45	32	34	40
SO₂	22,638	13,331	1,827	1,509	1,288	1,423	1,327
Fossil Fuel Combustion	21,482	13,235	1,770	1,447	1,138	1,272	1,176
Electric Power Sector	14,432	9,436	1,189	921	758	898	819
Industrial	2,886	1,378	259	234	172	168	159
Transportation ^a	793	724	45	40	23	24	25
Commercial	485	318	18	19	13	14	13
Residential	2,886	1,378	259	234	172	168	159
Petroleum and Natural Gas Systems	156	96	56	61	150	151	151
International Bunker Fuels	NA	NA	NA	NA	NA	NA	NA

1 NA (Not Applicable)

2 ^a The scope of the NEI for aircraft related precursor emissions included under the transportation is different from the Inventory
3 reporting scope. The NEI precursor estimate methodology does not exclude emissions that could be considered international
4 bunkers given local impacts from these emissions. The precursor estimates are based on modeled using FAA- and state-
5 supplied landing and take-off data for all aircraft types (including ground support equipment and auxiliary engines) used for
6 public, private, and military purposes.

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

8 Source: (EPA 2023a). Emission categories from EPA (2023a) are aggregated into sectors and categories reported as shown in
9 Table 2-3

10 Methodology and Time-Series Consistency

11 Emission estimates for 1990 through 2022 were obtained from data published on the National
12 Emissions Inventory (NEI) Air Pollutant Emissions Trends Data website (EPA 2023a). For Table 3-114, NEI
13 reported emissions of CO, NO_x, NMVOCs, and SO₂ were recategorized from NEI Emissions Inventory
14 System (EIS) sectors to source categories more closely aligned with sectors and categories in this
15 report, based on discussions between the EPA *Inventory* and NEI staff (see crosswalk documented in
16 Annex 6.3).⁸⁹ EIS sectors mapped to the energy sector categories in this report include: fuel combustion
17 for electric utilities, industrial, and other; petroleum and related industries; highway vehicles; off-
18 highway; and other mobile sources (e.g., commercial marine vessels and rail). As described in the NEI

⁸⁹ 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, SO₂, 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.

1 Technical Support Documentation (TSD) (EPA 2023b), NEI emissions are estimated through a
2 combination of emissions data submitted directly to the EPA by state, local, and tribal air agencies, as
3 well as additional information added by the Agency from EPA emissions programs, such as the emission
4 trading program, Toxics Release Inventory (TRI), and data collected during rule development or
5 compliance testing.

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