

2 4. Industrial Processes and Product Use

3 The Industrial Processes and Product Use (IPPU) chapter includes greenhouse gas emissions occurring from
4 industrial processes and from the use of greenhouse gases in products. The industrial processes and product use
5 categories included in this chapter are presented in Figure 4-1 and Figure 4-2. Greenhouse gas emissions from
6 industrial processes can occur in two different ways. First, they may be generated and emitted as the byproducts
7 of various non-energy-related industrial activities. Second, they may be emitted due to their use in manufacturing
8 processes or by end-consumers.

9 In the case of byproduct emissions, the emissions are generated by an industrial process itself and are not directly
10 a result of energy consumed during the process. For example, raw materials can be chemically or physically
11 transformed from one state to another. This transformation can result in the release of greenhouse gases such as
12 carbon dioxide (CO₂), methane (CH₄), nitrous oxide (N₂O), and fluorinated greenhouse gases (e.g., HFC-23). The
13 greenhouse gas byproduct generating processes included in this chapter include, iron and steel production and
14 metallurgical coke production, cement production, petrochemical production, lime production, ammonia
15 production, nitric acid production, other process uses of carbonates (e.g., flux stone, flue gas desulfurization, and
16 glass manufacturing), urea consumption for non-agricultural purposes, adipic acid production, HCFC-22
17 production, aluminum production, soda ash production and use, ferroalloy production, titanium dioxide
18 production, caprolactam, glyoxal, and glyoxylic acid production, glass production, zinc production, phosphoric acid
19 production, lead production, and silicon carbide production and consumption.

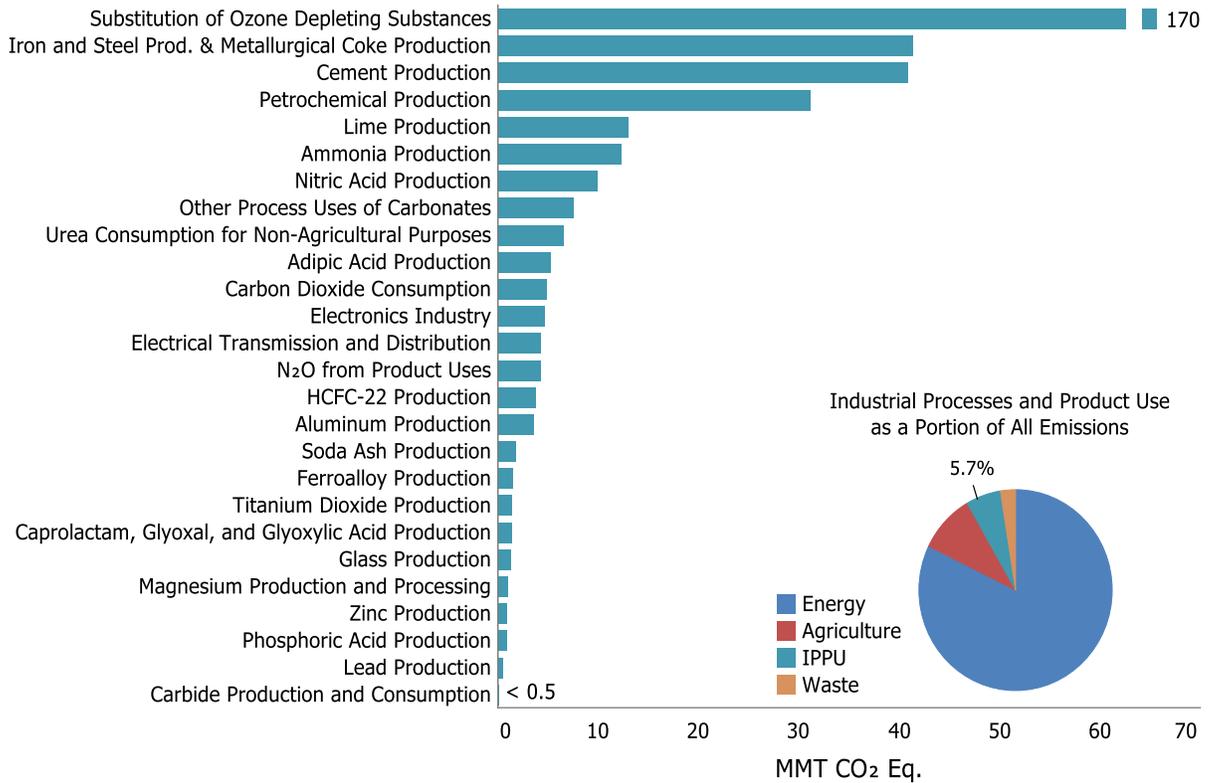
20 Greenhouse gases that are used in manufacturing processes or by end-consumers include man-made compounds
21 such as hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), sulfur hexafluoride (SF₆), and nitrogen trifluoride
22 (NF₃). The present contribution of HFCs, PFCs, SF₆, and NF₃ gases to the radiative forcing effect of all anthropogenic
23 greenhouse gases is small; however, because of their extremely long lifetimes, many of them will continue to
24 persist in the atmosphere long after they were first released. In addition, many of these gases have high global
25 warming potentials; SF₆ is the most potent greenhouse gas the Intergovernmental Panel on Climate Change (IPCC)
26 has evaluated. Use of HFCs is growing rapidly since they are the primary substitutes for ozone depleting substances
27 (ODS), which are being phased-out under the Montreal Protocol on Substances that Deplete the Ozone Layer.
28 Hydrofluorocarbons, PFCs, SF₆, and NF₃ are employed and emitted by a number of other industrial sources in the
29 United States, such as semiconductor manufacture, electric power transmission and distribution, and magnesium
30 metal production and processing. Carbon dioxide is also consumed and emitted through various end-use
31 applications. In addition, nitrous oxide is used in and emitted by semiconductor manufacturing and anesthetic and
32 aerosol applications.

33 In 2019, IPPU generated emissions of 374.0 million metric tons of CO₂ equivalent (MMT CO₂ Eq.), or 5.7 percent of
34 total U.S. greenhouse gas emissions.¹ Carbon dioxide emissions from all industrial processes were 167.7 MMT CO₂
35 Eq. (167,705 kt CO₂) in 2019, or 3.2 percent of total U.S. CO₂ emissions. Methane emissions from industrial

¹ Emissions reported in the IPPU chapter include those from all 50 states, including Hawaii and Alaska, as well as from U.S. Territories to the extent of which industries are occurring.

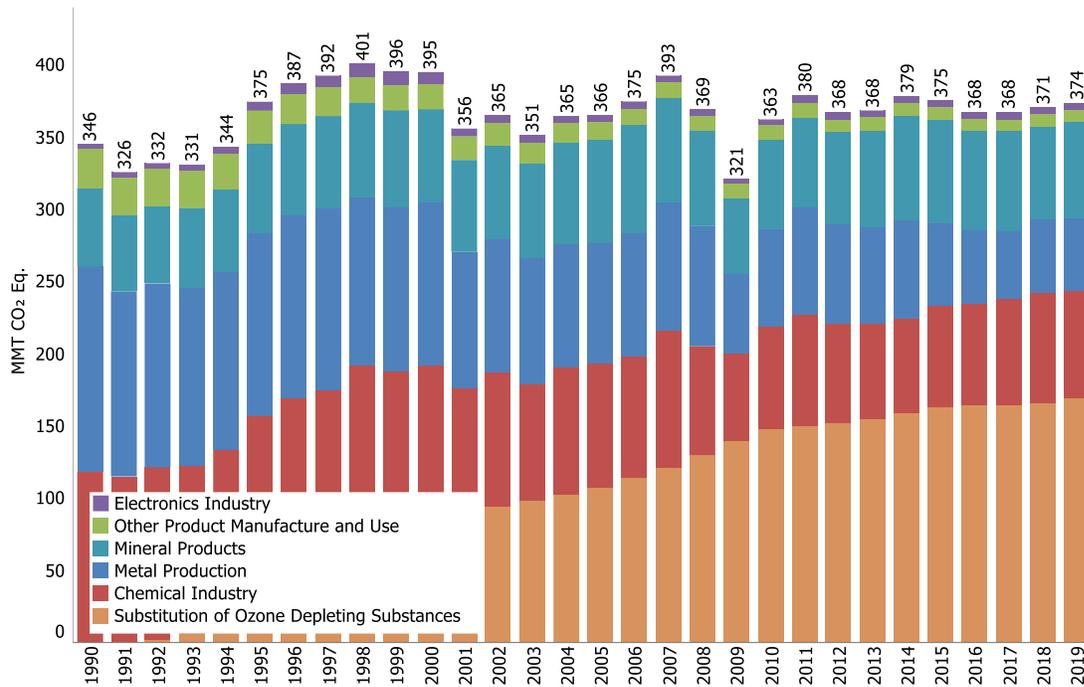
1 processes resulted in emissions of approximately 0.4 MMT CO₂ Eq. (15 kt CH₄) in 2019, which was less than 1
 2 percent of U.S. CH₄ emissions. Nitrous oxide emissions from IPPU were 21.1 MMT CO₂ Eq. (71 kt N₂O) in 2019, or
 3 4.6 percent of total U.S. N₂O emissions. In 2019 combined emissions of HFCs, PFCs, SF₆, and NF₃ totaled 184.9
 4 MMT CO₂ Eq. Total emissions from IPPU in 2019 were 8.2 percent more than 1990 emissions. Indirect greenhouse
 5 gas emissions also result from IPPU and are presented in Table 4-112 in kilotons (kt).

6 **Figure 4-1: 2019 Industrial Processes and Product Use Chapter Greenhouse Gas Sources**



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1 **Figure 4-2: Trends in Industrial Processes and Product Use Chapter Greenhouse Gas Sources**



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3 The increase in overall IPPU emissions since 1990 reflects a range of emission trends among the emission sources,
4 as shown in Figure 4-2. Emissions resulting from most types of metal production have declined significantly since
5 1990, largely due to production shifting to other countries, but also due to transitions to less-emissive methods of
6 production (in the case of iron and steel) and to improved practices (in the case of PFC emissions from aluminum
7 production). Carbon dioxide and CH₄ emissions from many chemical production sources have either decreased or
8 not changed significantly since 1990, with the exception of petrochemical production, Carbon Dioxide
9 Consumption, and Urea Consumption for Non-Agricultural Purposes which has steadily increased. Emissions from
10 mineral sources have either increased (e.g., cement manufacturing) or not changed significantly (e.g., glass and
11 lime manufacturing) since 1990 but largely follow economic cycles. Hydrofluorocarbon emissions from the
12 substitution of ODS have increased drastically since 1990 and are the largest source of IPPU emissions (45.4
13 percent in 2019), while the emissions of HFCs, PFCs, SF₆, and NF₃ from other sources have generally declined.
14 Nitrous oxide emissions from the production of adipic and nitric acid have decreased, while N₂O emissions from
15 product uses have remained nearly constant over time. Some emission sources exhibit varied interannual trends.
16 Trends are explained further within each emission source category throughout the chapter. Table 4-1 summarizes
17 emissions for the IPPU chapter in MMT CO₂ Eq. using *IPCC Fourth Assessment Report (AR4)* GWP values, following
18 the requirements of the current United Nations Framework Convention on Climate Change (UNFCCC) reporting
19 guidelines for national inventories (IPCC 2007).² Unweighted native gas emissions in kt are also provided in Table
20 4-2. The source descriptions that follow in the chapter are presented in the order as reported to the UNFCCC in the
21 Common Reporting Format (CRF) tables, corresponding generally to: mineral products, chemical production, metal
22 production, and emissions from the uses of HFCs, PFCs, SF₆, and NF₃.

23 Each year, some emission and sink estimates in the IPPU sector of the Inventory are recalculated and revised with
24 improved methods and/or data. In general, recalculations are made to the U.S. greenhouse gas emission estimates
25 either to incorporate new methodologies or, most commonly, to update recent historical data. These

² See <<http://unfccc.int/resource/docs/2013/cop19/eng/10a03.pdf>>.

1 improvements are implemented consistently across the previous Inventory's time series (i.e., 1990 to 2018) to
 2 ensure that the trend is accurate.

3 This year's estimates of HFC emissions from use of Ozone Depleting Substances Substitutes reflect updates to
 4 market size, substitute transitions, and charge size assumptions for Metered Dose Inhalers (MDI) aerosols to align
 5 with stakeholder input and market research. Market transitions for the ice maker end-use were updated based on
 6 manufacturer information on refrigerant use. In addition, several updates to the foam sector were implemented.
 7 The commercial refrigeration foam end-use was replaced with ten discrete commercial refrigeration application
 8 end-uses, in order to better define a market that was not adequately encompassed by the current commercial
 9 refrigeration foam end-use. Within the domestic refrigerator foam end-use, manufacturing emissions were
 10 adjusted to only include equipment manufactured within the United States, including those that are produced for
 11 export, and excluding those that are imported with foam. Market size, manufacturing loss rate, disposal lost rate,
 12 and post-life emission rate assumptions were also updated for PU and PIR boardstock foams based on market
 13 research.

14 Carbon content factors were also updated for the Iron and Steel emissions calculations. Finally, the methods to
 15 estimate the CO₂ emission factors to recalculate emissions for earlier parts of the time series (i.e., 1990 to 2009)
 16 for petrochemical subcategories ethylene, ethylene dichloride and vinyl chloride monomer, and carbon black were
 17 updated to reflect GHGRP data updates. Together, these updates decreased greenhouse gas emissions an average
 18 of 1.1 MMT CO₂ Eq. (0.3 percent) across the time series.

19 Emissions reported in the IPPU chapter include those from all 50 states, including Hawaii and Alaska, as well as
 20 from U.S. Territories to the extent of which industries are occurring. See Annex 5 for more information on EPA's
 21 assessment of the sources not included in this inventory.

22 **Table 4-1: Emissions from Industrial Processes and Product Use (MMT CO₂ Eq.)**

Gas/Source	1990	2005	2015	2016	2017	2018	2019
CO₂	212.3	194.1	173.5	165.2	163.9	164.5	167.7
Iron and Steel Production & Metallurgical Coke Production	104.7	70.1	47.9	43.6	40.6	42.6	41.3
<i>Iron and Steel Production</i>	99.1	66.2	43.5	41.0	38.6	41.3	39.9
<i>Metallurgical Coke Production</i>	5.6	3.9	4.4	2.6	2.0	1.3	1.4
Cement Production	33.5	46.2	39.9	39.4	40.3	39.0	40.9
Petrochemical Production	21.6	27.4	28.1	28.3	28.9	29.3	30.8
Lime Production	11.7	14.6	13.3	12.5	12.9	13.1	13.0
Ammonia Production	13.0	9.2	10.6	10.2	11.1	12.2	12.3
Other Process Uses of Carbonates	6.3	7.6	12.2	11.0	9.9	7.5	7.5
Urea Consumption for Non- Agricultural Purposes	3.8	3.7	4.6	5.1	5.0	6.1	6.6
Carbon Dioxide Consumption	1.5	1.4	4.9	4.6	4.6	4.1	4.9
Ferroalloy Production	2.2	1.4	2.0	1.8	2.0	2.1	1.6
Soda Ash Production	1.4	1.7	1.7	1.7	1.8	1.7	1.8
Titanium Dioxide Production	1.2	1.8	1.6	1.7	1.7	1.5	1.5
Aluminum Production	6.8	4.1	2.8	1.3	1.2	1.5	1.9
Glass Production	1.5	1.9	1.3	1.2	1.3	1.3	1.3
Zinc Production	0.6	1.0	0.9	0.9	1.0	1.0	1.0
Phosphoric Acid Production	1.5	1.3	1.0	1.0	1.0	0.9	0.9
Lead Production	0.5	0.6	0.5	0.5	0.5	0.5	0.5
Carbide Production and Consumption	0.4	0.2	0.2	0.2	0.2	0.2	0.2
Magnesium Production and Processing	+	+	+	+	+	+	+
CH₄	0.3	0.1	0.2	0.3	0.3	0.3	0.4
Petrochemical Production	0.2	0.1	0.2	0.2	0.3	0.3	0.3
Ferroalloy Production	+	+	+	+	+	+	+

Carbide Production and Consumption	+	+	+	+	+	+	+
Iron and Steel Production & Metallurgical Coke Production	+	+	+	+	+	+	+
N₂O	33.3	24.9	22.2	23.3	22.7	25.8	21.1
Adipic Acid Production	15.2	7.1	4.3	7.0	7.4	10.3	5.3
Nitric Acid Production	12.1	11.3	11.6	10.1	9.3	9.6	10.0
N ₂ O from Product Uses	4.2	4.2	4.2	4.2	4.2	4.2	4.2
Caprolactam, Glyoxal, and Glyoxylic Acid Production	1.7	2.1	1.9	1.7	1.5	1.4	1.4
Electronics Industry	+	0.1	0.2	0.2	0.3	0.3	0.2
HFCs	46.5	127.5	168.3	168.1	170.1	169.3	173.8
Substitution of Ozone Depleting Substances ^a	0.2	107.3	163.6	164.9	164.5	165.5	169.7
HFC-22 Production	46.1	20.0	4.3	2.8	5.2	3.3	3.7
Electronics Industry	0.2	0.2	0.3	0.3	0.4	0.4	0.3
Magnesium Production and Processing	0.0	0.0	0.1	0.1	0.1	0.1	0.1
PFCs	24.3	6.7	5.2	4.4	4.1	4.7	4.5
Electronics Industry	2.8	3.3	3.1	2.9	2.9	3.0	2.7
Aluminum Production	21.5	3.4	2.1	1.4	1.1	1.6	1.8
Substitution of Ozone Depleting Substances	0.0	+	+	+	+	0.1	0.1
SF₆	28.8	11.8	5.5	6.0	5.9	5.8	6.0
Electrical Transmission and Distribution	23.2	8.4	3.8	4.1	4.2	3.9	4.2
Magnesium Production and Processing	5.2	2.7	1.0	1.1	1.1	1.1	1.0
Electronics Industry	0.5	0.7	0.7	0.8	0.7	0.8	0.8
NF₃	+	0.5	0.6	0.6	0.6	0.6	0.6
Electronics Industry	+	0.5	0.6	0.6	0.6	0.6	0.6
Unspecified Mix of HFCs, PFCs, SF₆, and NF₃	+						
Electronics Industry	+	+	+	+	+	+	+
Total	345.5	365.7	375.4	367.9	367.6	371.0	374.0

Note: Totals may not sum due to independent rounding.

+ Does not exceed 0.05 MMT CO₂ Eq.

^a Small amounts of PFC emissions also result from this source.

1 **Table 4-2: Emissions from Industrial Processes and Product Use (kt)**

Gas/Source	1990	2005	2015	2016	2017	2018	2019
CO₂	212,317	194,068	173,517	165,219	163,864	164,537	167,705
Iron and Steel Production & Metallurgical Coke Production	104,730	70,076	47,941	43,621	40,566	42,627	41,290
<i>Iron and Steel Production</i>	99,122	66,155	43,525	40,979	38,587	41,345	39,924
<i>Metallurgical Coke Production</i>	5,608	3,921	4,417	2,643	1,978	1,282	1,366
Cement Production	33,484	46,194	39,907	39,439	40,324	38,971	40,896
Petrochemical Production	21,611	27,383	28,062	28,310	28,910	29,314	30,792
Lime Production	11,700	14,552	13,333	12,545	12,875	13,112	12,963
Ammonia Production	13,047	9,177	10,616	10,245	11,112	12,163	12,272
Other Process Uses of Carbonates	6,297	7,644	12,182	10,972	9,933	7,469	7,457
Urea Consumption for Non-Agricultural Purposes	3,784	3,653	4,578	5,132	4,972	6,056	6,569
Carbon Dioxide Consumption	1,472	1,375	4,940	4,640	4,580	4,130	4,870
Ferroalloy Production	2,152	1,392	1,960	1,796	1,975	2,063	1,598
Soda Ash Production	1,431	1,655	1,714	1,723	1,753	1,714	1,792
Titanium Dioxide Production	1,195	1,755	1,635	1,662	1,688	1,541	1,474

Aluminum Production	6,831	4,142	2,767	1,334	1,205	1,451	1,880
Glass Production	1,535	1,928	1,299	1,249	1,296	1,305	1,280
Zinc Production	632	1,030	933	882	951	982	964
Phosphoric Acid Production	1,529	1,342	999	998	1,028	940	891
Lead Production	516	553	473	500	513	513	540
Carbide Production and Consumption	370	213	176	170	181	184	175
Magnesium Production and Processing	1	3	3	3	3	1	1
CH₄	12	4	9	11	11	13	15
Petrochemical Production	9	3	7	10	10	12	13
Ferroalloy Production	1	+	1	1	1	1	+
Carbide Production and Consumption	1	+	+	+	+	+	+
Iron and Steel Production & Metallurgical Coke Production	1	1	+	+	+	+	+
N₂O	112	84	74	78	76	87	71
Adipic Acid Production	51	24	14	23	25	35	18
Nitric Acid Production	41	38	39	34	31	32	34
N ₂ O from Product Uses	14	14	14	14	14	14	14
Caprolactam, Glyoxal, and Glyoxylic Acid Production	6	7	6	6	5	5	5
Electronics Industry	+	+	1	1	1	1	1
HFCs	M	M	M	M	M	M	M
Substitution of Ozone Depleting Substances ^a	M	M	M	M	M	M	M
HCFC-22 Production	3	1	+	+	+	+	+
Electronics Industry	M	M	M	M	M	M	M
Magnesium Production and Processing	0	0	+	+	+	+	+
PFCs	M	M	M	M	M	M	M
Electronics Industry	M	M	M	M	M	M	M
Aluminum Production	M	M	M	M	M	M	M
Substitution of Ozone Depleting Substances	0	+	+	+	+	+	+
SF₆	1	1	+	+	+	+	+
Electrical Transmission and Distribution	1	+	+	+	+	+	+
Magnesium Production and Processing	+	+	+	+	+	+	+
Electronics Industry	+	+	+	+	+	+	+
NF₃	+	+	+	+	+	+	+
Electronics Industry	+	+	+	+	+	+	+
Unspecified Mix of HFCs, PFCs, SF₆, and NF₃	M	M	M	M	M	M	M
Electronics Industry	M	M	M	M	M	M	M

Note: Totals may not sum due to independent rounding.

+ Does not exceed 0.5 kt.

M (Mixture of gases)

^a Small amounts of PFC emissions also result from this source.

- 1 This chapter presents emission estimates calculated in accordance with the *2006 IPCC Guidelines for National Greenhouse Gas Inventories (2006 IPCC Guidelines)* and its refinements. For additional detail on IPPU sources that
- 2 are not included in this Inventory report, please review Annex 5, Assessment of the Sources and Sinks of
- 3 Greenhouse Gas Emissions Not Included. These sources are not included due to various national circumstances,
- 4 such as that emissions from a source may not currently occur in the United States, data are not currently available
- 5 for those emission sources (e.g., ceramics, non-metallurgical magnesium production, glyoxal and glyoxylic acid
- 6 production, CH₄ from direct reduced iron production), emissions are included elsewhere within the Inventory
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1 report, or data suggest that emissions are not significant (e.g., various fluorinated gas emissions from the
2 electronics industry and other produce uses). Information on planned improvements for specific IPPU source
3 categories can be found in the Planned Improvements section of the individual source category.

4 In addition, as mentioned in the Energy chapter of this report (Box 3-5), fossil fuels consumed for non-energy uses
5 for primary purposes other than combustion for energy (including lubricants, paraffin waxes, bitumen asphalt, and
6 solvents) are reported in the Energy chapter. According to the *2006 IPCC Guidelines*, these non-energy uses of
7 fossil fuels are to be reported under the IPPU, rather than the Energy sector; however, due to national
8 circumstances regarding the allocation of energy statistics and carbon balance data, the United States reports
9 these non-energy uses in the Energy chapter of this Inventory. Although emissions from these non-energy uses are
10 reported in the Energy chapter, the methodologies used to determine emissions are compatible with the *2006*
11 *IPCC Guidelines* and are well documented and scientifically based. The methodologies used, as described in Section
12 3.2, Carbon Emitted from Non-Energy Uses of Fossil Fuels and Annex 2.3, Methodology for Estimating Carbon
13 Emitted from Non-Energy Uses of Fossil Fuels. The emissions are reported under the Energy chapter to improve
14 transparency, report a more complete carbon balance, and avoid double counting. For example, only the emissions
15 from the first use of lubricants and waxes are to be reported under the IPPU sector, and emissions from use of
16 lubricants in 2-stroke engines and emissions from secondary use of lubricants and waxes in waste incineration with
17 energy recovery are to be reported under the Energy sector. Reporting non-energy use emissions from only first
18 use of lubricants and waxes under IPPU would involve making artificial adjustments to the non-energy use carbon
19 balance and could potentially result in double counting of emissions. These artificial adjustments would also be
20 required for asphalt and road oil and solvents (which are captured as part of petrochemical feedstock emissions)
21 and could also potentially result in double counting of emissions. For more information, see the Methodology
22 discussion in Section 3.1, CO₂ from Fossil Fuel Combustion, Section 3.2, Carbon Emitted from Non-Energy Uses of
23 Fossil Fuels and Annex 2.3, Methodology for Estimating Carbon Emitted from Non-Energy Uses of Fossil Fuels.

24 Finally, as stated in the Energy chapter, portions of the fuel consumption data for seven fuel categories—coking
25 coal, distillate fuel, industrial other coal, petroleum coke, natural gas, residual fuel oil, and other oil—are
26 reallocated to the IPPU chapter, as they are consumed during non-energy related industrial process activity.
27 Emissions from uses of fossil fuels as feedstocks or reducing agents (e.g., petrochemical production, aluminum
28 production, titanium dioxide and zinc production) are reported in the IPPU chapter, unless otherwise noted due to
29 specific national circumstances. This approach is compatible with the *2006 IPCC Guidelines* and is well documented
30 and scientifically based. The emissions from these feedstocks and reducing agents are reported under the IPPU
31 chapter to improve transparency and to avoid double counting of emissions under both the Energy and IPPU
32 sectors. More information on the methodology to adjust for these emissions within the Energy chapter is
33 described in the Methodology section of CO₂ from Fossil Fuel Combustion (3.1 Fossil Fuel Combustion [CRF Source
34 Category 1A]) and Annex 2.1, Methodology for Estimating Emissions of CO₂ from Fossil Fuel Combustion.
35 Additional information is listed within each IPPU emission source in which this approach applies.

37 **Box 4-1: Methodological Approach for Estimating and Reporting U.S. Emissions and Removals**

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

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QA/QC and Verification Procedures

For IPPU sources, a detailed QA/QC plan was developed and implemented for specific categories. This plan is consistent with the U.S. Inventory QA/QC plan outlined in Annex 8 but was tailored to include specific procedures recommended for these sources. The IPPU QA/QC Plan does not replace the Inventory QA/QC Plan, but rather provides more context for the IPPU sector. The IPPU QA/QC Plan provides the completed QA/QC forms for each inventory reports, as well as, for certain source categories (e.g., key categories), more detailed documentation of quality control checks and recalculations due to methodological changes.

Two types of checks were performed using this plan: (1) general (Tier 1) procedures consistent with Volume 1, Chapter 6 of the *2006 IPCC Guidelines* that focus on annual procedures and checks to be used when gathering, maintaining, handling, documenting, checking, and archiving the data, supporting documents, and files; and (2) source category-specific (Tier 2) procedures that focus on checks and comparisons of the emission factors, activity data, and methodologies used for estimating emissions from the relevant industrial process and product use sources. Examples of these procedures include: checks to ensure that activity data and emission estimates are consistent with historical trends to identify significant changes; that, where possible, consistent and reputable data sources are used and specified across sources; that interpolation or extrapolation techniques are consistent across sources; and that common datasets, units, and conversion factors are used where applicable. The IPPU QA/QC plan also checked for transcription errors in data inputs required for emission calculations, including activity data and emission factors; and confirmed that estimates were calculated and reported for all applicable and able portions of the source categories for all years.

For sources that use data from EPA’s Greenhouse Gas Reporting Program (GHGRP), EPA verifies annual facility-level reports through a multi-step process (e.g., including a combination of pre-and post-submittal electronic checks and manual reviews by staff) to identify potential errors and ensure that data submitted to EPA are accurate, complete, and consistent.³ Based on the results of the verification process, EPA follows up with facilities to resolve mistakes that may have occurred. The post-submittals checks are consistent with a number of general and category-specific QC procedures, including: range checks, statistical checks, algorithm checks, and year-to-year checks of reported data and emissions. See Box 4-2 below for more information on use of GHGRP data in this chapter.

General QA/QC procedures (Tier 1) and calculation-related QC (category-specific, Tier 2) have been performed for all IPPU sources. Consistent with the *2006 IPCC Guidelines*, additional category-specific QC procedures were performed for more significant emission categories (such as the comparison of reported consumption with modeled consumption using EPA’s Greenhouse Gas Reporting Program (GHGRP) data within Substitution of Ozone Depleting Substances) or sources where significant methodological and data updates have taken place. The QA/QC implementation did not reveal any significant inaccuracies, and all errors identified were documented and corrected. Application of these procedures, specifically category-specific QC procedures and updates/improvements as a result of QA processes (expert, public, and UNFCCC technical expert reviews), are described further within respective source categories, in the Recalculations and Planned Improvement sections.

For most IPPU categories, activity data are obtained via aggregation of facility-level data from EPA’s GHGRP (See Box 4-2 below and Annex 9), national commodity surveys conducted by U.S. Geological Survey National Minerals Information Center, U.S. Department of Energy (DOE), U.S. Census Bureau, industry associations such as Air-Conditioning, Heating, and Refrigeration Institute (AHRI), American Chemistry Council (ACC), and American Iron and Steel Institute (AISI) (specified within each source category). The emission factors used include those derived from the EPA’s GHGRP and application of IPCC default factors. Descriptions of uncertainties and assumptions for

³ See <https://www.epa.gov/sites/production/files/2015-07/documents/ghgrp_verification_factsheet.pdf>.

1 activity data and emission factors are included within the uncertainty discussion sections for each IPPU source
2 category.

3 **Box 4-2: Industrial Process and Product Use Data from EPA's Greenhouse Gas Reporting Program**

EPA collects greenhouse gas emissions data from individual facilities and suppliers of certain fossil fuels and industrial gases through its Greenhouse Gas Reporting Program (GHGRP). The GHGRP applies to direct greenhouse gas emitters, fossil fuel suppliers, industrial gas suppliers, and facilities that inject CO₂ underground for sequestration or other reasons and requires reporting by sources or suppliers in 41 industrial categories. Annual reporting is at the facility level, except for certain suppliers of fossil fuels and industrial greenhouse gases.

In general, the threshold for reporting is 25,000 metric tons or more of CO₂ Eq. per year, but reporting is required for all facilities in some industries. Calendar year 2010 was the first year for which data were collected for facilities subject to 40 CFR Part 98, though some source categories first collected data for calendar year 2011. See Annex 9 "Use of EPA Greenhouse Gas Reporting Program in Inventory" for more information.

EPA uses annual GHGRP data in a number of categories to improve the national estimates presented in this Inventory, consistent with IPCC guidelines (e.g., minerals, chemicals, product uses). Methodologies used in EPA's GHGRP are consistent with IPCC guidelines, including higher tier methods; however, it should be noted that the definitions for source categories in EPA's GHGRP may differ from those used in this Inventory in meeting the UNFCCC reporting guidelines (IPCC 2011). In line with the UNFCCC reporting guidelines, the Inventory is a comprehensive accounting of all emissions from source categories identified in the *2006 IPCC Guidelines*. EPA has paid particular attention to ensuring both completeness and time-series consistency for major recalculations that have occurred from the incorporation of GHGRP data into these categories, consistent with *2006 IPCC Guidelines* and *IPCC Technical Bulletin on Use of Facility-Specific Data in National GHG Inventories*.⁴

For certain source categories in this Inventory (e.g., nitric acid production, lime production, cement production, petrochemical production, carbon dioxide consumption, ammonia production, and urea consumption for non-agricultural purposes), EPA has integrated data values that have been calculated by aggregating GHGRP data that are considered confidential business information (CBI) at the facility level. EPA, with industry engagement, has put forth criteria to confirm that a given data aggregation shields underlying CBI from public disclosure. EPA is only publishing data values that meet these aggregation criteria.⁵ Specific uses of aggregated facility-level data are described in the respective methodological sections (e.g., including other sources using GHGRP data that is not aggregated CBI, such as aluminum, electronics industry, electrical transmission and distribution, HCFC-22 production, and magnesium production and processing.). For other source categories in this chapter, as indicated in the respective planned improvements sections,⁶ EPA is continuing to analyze how facility-level GHGRP data may be used to improve the national estimates presented in this Inventory, giving particular consideration to ensuring time-series consistency and completeness.

Additionally, EPA's GHGRP has and will continue to enhance QA/QC procedures and assessment of uncertainties within the IPPU categories (see those categories for specific QA/QC details regarding the use of GHGRP data).

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⁴ See <http://www.ipcc-nggip.iges.or.jp/public/tb/TFI_Technical_Bulletin_1.pdf>.

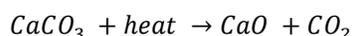
⁵ U.S. EPA Greenhouse Gas Reporting Program. Developments on Publication of Aggregated Greenhouse Gas Data, November 25, 2014. See <<http://www.epa.gov/ghgreporting/confidential-business-information-ghg-reporting>>.

⁶ Ammonia Production, Glass Production, Lead Production, and Other Fluorinated Gas Production.

4.1 Cement Production (CRF Source Category 2A1)

Cement production is an energy- and raw material-intensive process that results in the generation of carbon dioxide (CO₂) both from the energy consumed in making the clinker precursor to cement and from the chemical process to make the clinker. Emissions from fuels consumed for energy purposes during the production of cement are accounted for in the Energy chapter.

During the clinker production process, the key reaction occurs when calcium carbonate (CaCO₃), in the form of limestone or similar rocks, is heated in a cement kiln at a temperature range of about 700 to 1,000 degrees Celsius (1,300 to 1,800 degrees Fahrenheit) to form lime (i.e., calcium oxide, or CaO) and CO₂ in a process known as calcination or calcining. The quantity of CO₂ emitted during clinker production is directly proportional to the lime content of the clinker. During calcination, each mole of CaCO₃ heated in the clinker kiln forms one mole of CaO and one mole of CO₂. The CO₂ is vented to the atmosphere as part of the kiln lime exhaust:



Next, over a temperature range of 1000 to 1450 degrees Celsius, the CaO combines with alumina, iron oxide and silica that are also present in the clinker raw material mix to form hydraulically reactive compounds within white-hot semifused (sintered) nodules of clinker. Because these “sintering” reactions are highly exothermic, they produce few CO₂ process emissions. The clinker is then rapidly cooled to maintain quality and then very finely ground with a small amount of gypsum and potentially other materials (e.g., ground granulated blast furnace slag, etc.) to make Portland and similar cements.⁷

Carbon dioxide emitted from the chemical process of cement production is the second largest source of industrial CO₂ emissions in the United States. Cement is produced in 34 states and Puerto Rico. Texas, California, Missouri, Florida, Alabama, Michigan, and Pennsylvania were the leading cement-producing states in 2019 and accounted for almost 60 percent of total U.S. production (USGS 2020). Clinker production in 2019 remained at relatively flat levels, compared to 2018 (EPA 2020; USGS 2020). In 2019, cement sales increased slightly, and imports of clinker for consumption increased by approximately 14 percent from 2018 (USGS 2020). In 2019, U.S. clinker production totaled 78,600 kilotons (EPA 2020). The resulting CO₂ emissions were estimated to be 40.9 MMT CO₂ Eq. (40,896 kt) (see Table 4-3).

Table 4-3: CO₂ Emissions from Cement Production (MMT CO₂ Eq. and kt)

Year	MMT CO ₂ Eq.	kt
1990	33.5	33,484
2005	46.2	46,194
2015	39.9	39,907
2016	39.4	39,439
2017	40.3	40,324
2018	39.0	38,971
2019	40.9	40,896

Greenhouse gas emissions from cement production, which are primarily driven by production levels, increased every year from 1991 through 2006 but decreased in the following years until 2009. Since 1990, emissions have

⁷ Approximately three percent of total clinker production is used to produce masonry cement, which is produced using plasticizers (e.g., ground limestone, lime, etc.) and Portland cement (USGS 2011). Carbon dioxide emissions that result from the production of lime used to create masonry cement are included in Section 4.2 Lime Production (CRF Source Category 2A2).

1 increased by 22 percent. Emissions from cement production were at their lowest levels in 2009 (2009 emissions
2 are approximately 28 percent lower than 2008 emissions and 12 percent lower than 1990) due to the economic
3 recession and the associated decrease in demand for construction materials. Since 2010, emissions have increased
4 by about 30 percent, due to increasing demand for cement. Cement continues to be a critical component of the
5 construction industry; therefore, the availability of public and private construction funding, as well as overall
6 economic conditions, have considerable impact on the level of cement production.

7 Methodology

8 Carbon dioxide emissions from cement production were estimated using the Tier 2 methodology from the 2006
9 IPCC Guidelines as this is a key category. The Tier 2 methodology was used because detailed and complete data
10 (including weights and composition) for carbonate(s) consumed in clinker production are not available,⁸ and thus a
11 rigorous Tier 3 approach is impractical. Tier 2 specifies the use of aggregated plant or national clinker production
12 data and an emission factor, which is the product of the average lime fraction for clinker of 65 percent and a
13 constant reflecting the mass of CO₂ released per unit of lime. The U.S. Geological Survey (USGS) mineral
14 commodity expert for cement has confirmed that this is a reasonable assumption for the United States (Van Oss
15 2013a). This calculation yields an emission factor of 0.510 tons of CO₂ per ton of clinker produced, which was
16 determined as follows:

$$17 \quad EF_{\text{clinker}} = 0.650 \text{ CaO} \times [(44.01 \text{ g/mole CO}_2) \div (56.08 \text{ g/mole CaO})] = 0.510 \text{ tons CO}_2/\text{ton clinker}$$

18 During clinker production, some of the raw materials, partially reacted raw materials, and clinker enters the kiln
19 line's exhaust system as non-calcinated, partially calcinated, or fully calcinated cement kiln dust (CKD). To the
20 degree that the CKD contains carbonate raw materials which are then calcined, there are associated CO₂ emissions.
21 At some plants, essentially all CKD is directly returned to the kiln, becoming part of the raw material feed, or is
22 likewise returned to the kiln after first being removed from the exhaust. In either case, the returned CKD becomes
23 a raw material, thus forming clinker, and the associated CO₂ emissions are a component of those calculated for the
24 clinker overall. At some plants, however, the CKD cannot be returned to the kiln because it is chemically unsuitable
25 as a raw material, or chemical issues limit the amount of CKD that can be so reused. Any clinker that cannot be
26 returned to the kiln is either used for other (non-clinker) purposes or is landfilled. The CO₂ emissions attributable
27 to the non-returned calcinated portion of the CKD are not accounted for by the clinker emission factor and thus a
28 CKD correction factor should be applied to account for those emissions. The USGS reports the amount of CKD used
29 to produce clinker, but no information is currently available on the total amount of CKD produced annually.⁹
30 Because data are not currently available to derive a country-specific CKD correction factor, a default correction
31 factor of 1.02 (2 percent) was used to account for CKD CO₂ emissions, as recommended by the IPCC (IPCC 2006).¹⁰
32 Total cement production emissions were calculated by adding the emissions from clinker production and the
33 emissions assigned to CKD.

34 Small amounts of impurities (i.e., not calcium carbonate) may exist in the raw limestone used to produce clinker.
35 The proportion of these impurities is generally minimal, although a small amount (1 to 2 percent) of magnesium
36 oxide (MgO) may be desirable as a flux. Per the IPCC Tier 2 methodology, a correction for MgO is not used, since

⁸ As discussed further under "Planned Improvements," most cement-producing facilities that report their emissions to the GHGRP use CEMS to monitor combined process and fuel combustion emissions for kilns, making it difficult to quantify the process emissions on a facility-specific basis. In 2019, the percentage of facilities not using CEMS was 8 percent.

⁹ The USGS *Minerals Yearbook: Cement* notes that CKD values used for clinker production are likely underreported.

¹⁰ As stated on p. 2.12 of the 2006 IPCC Guidelines, Vol. 3, Chapter 2: "...As data on the amount of CKD produced may be scarce (except possibly for plant-level reporting), estimating emissions from lost CKD based on a default value can be considered good practice. The amount of CO₂ from lost CKD can vary, but ranges typically from about 1.5 percent (additional CO₂ relative to that calculated for clinker) for a modern plant to about 20 percent for a plant losing a lot of highly calcinated CKD (van Oss, 2005). In the absence of data, the default CKD correction factor (CF_{ckd}) is 1.02 (i.e., add 2 percent to the CO₂ calculated for clinker). If no calcined CKD is believed to be lost to the system, the CKD correction factor will be 1.00 (van Oss, 2005)..."

1 the amount of MgO from carbonate is likely very small and the assumption of a 100 percent carbonate source of
 2 CaO already yields an overestimation of emissions (IPCC 2006).

3 The 1990 through 2012 activity data for clinker production (see Table 4-4) were obtained from USGS (Van Oss
 4 2013a, Van Oss 2013b). Clinker production data for 2013 were also obtained from USGS (USGS 2014). USGS
 5 compiled the data (to the nearest ton) through questionnaires sent to domestic clinker and cement manufacturing
 6 plants, including facilities in Puerto Rico. Clinker production values in the current Inventory report utilize GHGRP
 7 data for the years 2014 through 2019 (EPA 2020). Details on how this GHGRP data compares to USGS reported
 8 data can be found in the section on QA/QC and Verification.

9 **Table 4-4: Clinker Production (kt)**

Year	Clinker
1990	64,355
2005	88,783
2015	76,700
2016	75,800
2017	77,500
2018	74,900
2019	78,600

Notes: Clinker production from 1990 through 2019 includes Puerto Rico (relevant U.S. Territories).

10 Uncertainty and Time-Series Consistency – TO BE UPDATED

11 The uncertainties contained in these estimates are primarily due to uncertainties in the lime content of clinker and
 12 in the percentage of CKD recycled inside the cement kiln. Uncertainty is also associated with the assumption that
 13 all calcium-containing raw materials are CaCO₃, when a small percentage likely consists of other carbonate and
 14 non-carbonate raw materials. The lime content of clinker varies from 60 to 67 percent; 65 percent is used as a
 15 representative value (Van Oss 2013a). The amount of CO₂ from CKD loss can range from 1.5 to 8 percent
 16 depending upon plant specifications. Additionally, some amount of CO₂ is reabsorbed when the cement is used for
 17 construction. As cement reacts with water, alkaline substances such as calcium hydroxide are formed. During this
 18 curing process, these compounds may react with CO₂ in the atmosphere to create calcium carbonate. This reaction
 19 only occurs in roughly the outer 0.2 inches of the total thickness. Because the amount of CO₂ reabsorbed is
 20 thought to be minimal, it was not estimated.

21 The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-5. Based on the
 22 uncertainties associated with total U.S. clinker production, the CO₂ emission factor for clinker production, and the
 23 emission factor for additional CO₂ emissions from CKD, 2019 CO₂ emissions from cement production were
 24 estimated to be between 37.8 and 42.8 MMT CO₂ Eq. at the 95 percent confidence level. This confidence level
 25 indicates a range of approximately 6 percent below and 6 percent above the emission estimate of 40.9 MMT CO₂
 26 Eq.

27 **Table 4-5: Approach 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Cement**
 28 **Production (MMT CO₂ Eq. and Percent)**

Source	Gas	2019 Emission Estimate (MMT CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a (MMT CO ₂ Eq.)			
			Lower Bound	Upper Bound	Lower Bound (%)	Upper Bound (%)
Cement Production	CO ₂	40.9	37.8	42.8	-6%	+6%

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

1 Methodological approaches were applied to the entire time series to ensure time-series consistency from 1990
2 through 2018. Details on the emission trends through time are described in more detail in the Methodology
3 section, above.

4 QA/QC and Verification

5 General quality assurance/quality control (QA/QC) procedures were applied consistent with the U.S. Inventory
6 QA/QC plan, which is in accordance with Volume 1, Chapter 6 of *2006 IPCC Guidelines* as described in the
7 introduction of the IPPU chapter (see Annex 8 for more details).

8 EPA relied upon the latest guidance from the IPCC on the use of facility-level data in national inventories and
9 applied a category-specific QC process to compare activity data from EPA's GHGRP with existing data from USGS
10 surveys. This was to ensure time-series consistency of the emission estimates presented in the Inventory. Total
11 U.S. clinker production is assumed to have low uncertainty because facilities routinely measure this for economic
12 reasons and because both USGS and GHGRP take multiple steps to ensure that reported totals are accurate. EPA
13 verifies annual facility-level GHGRP reports through a multi-step process that is tailored to the reporting industry
14 (e.g., combination of electronic checks including range checks, statistical checks, algorithm checks, year-to-year
15 comparison checks, along with manual reviews involving outside data checks) to identify potential errors and
16 ensure that data submitted to EPA are accurate, complete, and consistent (EPA 2015). Based on the results of the
17 verification process, EPA follows up with facilities to resolve mistakes that may have occurred.¹¹ Facilities are also
18 required to monitor and maintain records of monthly clinker production per section 98.84 of the GHGRP regulation
19 (40 CFR 98.84).

20 EPA's GHGRP requires all facilities producing Portland cement to report greenhouse gas emissions, including CO₂
21 process emissions from each kiln, CO₂ combustion emissions from each kiln, CH₄ and N₂O combustion emissions
22 from each kiln, and CO₂, CH₄, and N₂O emissions from each stationary combustion unit other than kilns (40 CFR
23 Part 98 Subpart H). Source-specific quality control measures for the Cement Production category are included in
24 section 98.84, Monitoring and QA/QC Requirements.

25 As mentioned above, EPA compares GHGRP clinker production data to the USGS clinker production data. For the
26 year 2014 and 2018, USGS and GHGRP clinker production data showed a difference of approximately 2 percent
27 and 3 percent, respectively. In 2015, 2016, 2017, and 2019, that difference was less than 1 percent between the
28 two sets of activity data. This difference resulted in an increase of emissions compared to USGS data by less than
29 0.1 MMT CO₂ Eq. in 2015, 2016, 2017, and 2019. The information collected by the USGS National Minerals
30 Information Center surveys continue to be an important data source.

31 Recalculations Discussion

32 Recalculations were performed for year 2018 based on updated clinker production data from EPA's GHGRP.
33 Compared to the previous Inventory, emissions for 2018 decreased by 3 percent (1,353 kt CO₂ Eq.).

34 Planned Improvements

35 EPA is continuing to evaluate and analyze data reported under EPA's GHGRP that would be useful to improve the
36 emission estimates for the Cement Production source category. Most cement production facilities reporting under
37 EPA's GHGRP use Continuous Emission Monitoring Systems (CEMS) to monitor and report CO₂ emissions, thus
38 reporting combined process and combustion emissions from kilns. In implementing further improvements and
39 integration of data from EPA's GHGRP, the latest guidance from the IPCC on the use of facility-level data in national

¹¹ See GHGRP Verification Fact Sheet <https://www.epa.gov/sites/production/files/2015-07/documents/ghgrp_verification_factsheet.pdf>.

1 inventories will be relied upon, in addition to category-specific QC methods recommended by the 2006 IPCC
2 *Guidelines*.¹² EPA’s long-term improvement plan includes continued assessment of the feasibility of using
3 additional GHGRP information beyond aggregation of reported facility-level clinker data, in particular
4 disaggregating the combined process and combustion emissions reported using CEMS, to separately present
5 national process and combustion emissions streams consistent with IPCC and UNFCCC guidelines. This long-term
6 planned analysis is still in development and has not been applied for this current Inventory.

7 Finally, in response to feedback from Portland Cement Association (PCA) during the Public Review comment period
8 of a previous Inventory, EPA plans to work with PCA to discuss additional long-term improvements to review
9 methods and data used to estimate CO₂ emissions from cement production to account for both organic material
10 and magnesium carbonate in the raw material, and to discuss the carbonation that occurs across the duration of
11 the cement product. Priority will be to identify data and studies on the average MgO content of clinker produced in
12 the United States, the average carbon content for organic materials in kiln feed in the United States, and CO₂
13 reabsorption rates via carbonation for various cement products. This information is not reported by facilities
14 subject to report to GHGRP. EPA met with PCA in the fall of 2020 to discuss PCA’s latest research on carbonation.

15 4.2 Lime Production (CRF Source Category 16 2A2)

17 Lime is an important manufactured product with many industrial, chemical, and environmental applications. Lime
18 production involves three main processes: stone preparation, calcination, and hydration. Carbon dioxide (CO₂) is
19 generated during the calcination stage, when limestone—mostly calcium carbonate (CaCO₃)—is roasted at high
20 temperatures in a kiln to produce calcium oxide (CaO) and CO₂. The CO₂ is given off as a gas and is normally
21 emitted to the atmosphere.



23 Some of the CO₂ generated during the production process, however, is recovered at some facilities for use in sugar
24 refining and precipitated calcium carbonate (PCC) production.¹³ Emissions from fuels consumed for energy
25 purposes during the production of lime are included in the Energy chapter.

26 For U.S. operations, the term “lime” actually refers to a variety of chemical compounds. These include CaO, or
27 high-calcium quicklime; calcium hydroxide (Ca(OH)₂), or hydrated lime; dolomitic quicklime ([CaO•MgO]); and
28 dolomitic hydrate ([Ca(OH)₂•MgO] or [Ca(OH)₂•Mg(OH)₂]).

29 The current lime market is approximately distributed across five end-use categories, as follows: metallurgical uses,
30 34 percent; environmental uses, 30 percent; chemical and industrial uses, 21 percent; construction uses, 11
31 percent; and refractory dolomite, 1 percent (USGS 2020b). The major uses are in steel making, flue gas
32 desulfurization systems at coal-fired electric power plants, construction, and water treatment, as well as uses in
33 mining, pulp and paper and precipitated calcium carbonate manufacturing. Lime is also used as a CO₂ scrubber,
34 and there has been experimentation on the use of lime to capture CO₂ from electric power plants.

35 Lime production in the United States—including Puerto Rico—was reported to be 18,000 kilotons in 2019 (USGS
36 2020a). Lime production in 2019 decreased by about 1 percent compared to 2018 levels (USGS 2020a). At year-end
37 2019, there were 74 operating primary lime plants in the United States, including Puerto Rico according to the

¹² See IPCC Technical Bulletin on Use of Facility-Specific Data in National Greenhouse Gas Inventories <http://www.ipcc-nggip.iges.or.jp/public/tb/TFI_Technical_Bulletin_1.pdf>.

¹³ PCC is obtained from the reaction of CO₂ with calcium hydroxide. It is used as a filler and/or coating in the paper, food, and plastic industries.

1 USGS MCS (USGS 2020a).¹⁴ Principal lime producing states are Missouri, Alabama, Ohio, Texas, and Kentucky
 2 (USGS 2020a).
 3 U.S. lime production resulted in estimated net CO₂ emissions of 13.0 MMT CO₂ Eq. (12,963 kt) (see Table 4-6 and
 4 Table 4-7). The trends in CO₂ emissions from lime production are directly proportional to trends in production,
 5 which are described below.

6 **Table 4-6: CO₂ Emissions from Lime Production (MMT CO₂ Eq. and kt)**

Year	MMT CO ₂ Eq.	kt
1990	11.7	11,700
2005	14.6	14,552
2015	13.3	13,333
2016	12.5	12,545
2017	12.9	12,875
2018	13.1	13,112
2019	13.0	12,963

7 **Table 4-7: Gross, Recovered, and Net CO₂ Emissions from Lime Production (kt)**

Year	Gross	Recovered ^a	Net Emissions
1990	11,959	259	11,700
2005	15,074	522	14,552
2015	13,755	422	13,333
2016	12,915	370	12,545
2017	13,276	401	12,875
2018	13,615	503	13,112
2019	13,527	564	12,963

Note: Totals may not sum due to independent rounding.

^a For sugar refining and PCC production.

8 Methodology

9 To calculate emissions, the amounts of high-calcium and dolomitic lime produced were multiplied by their
 10 respective emission factors using the Tier 2 approach from the *2006 IPCC Guidelines*. The emission factor is the
 11 product of the stoichiometric ratio between CO₂ and CaO, and the average CaO and MgO content for lime. The
 12 CaO and MgO content for lime is assumed to be 95 percent for both high-calcium and dolomitic lime (IPCC 2006).
 13 The emission factors were calculated as follows:

14 For high-calcium lime:

$$15 \quad [(44.01 \text{ g/mole CO}_2) \div (56.08 \text{ g/mole CaO})] \times (0.9500 \text{ CaO/lime}) = 0.7455 \text{ g CO}_2/\text{g lime}$$

16 For dolomitic lime:

$$17 \quad [(88.02 \text{ g/mole CO}_2) \div (96.39 \text{ g/mole CaO})] \times (0.9500 \text{ CaO/lime}) = 0.8675 \text{ g CO}_2/\text{g lime}$$

18 Production was adjusted to remove the mass of chemically combined water found in hydrated lime, determined
 19 according to the molecular weight ratios of H₂O to (Ca(OH)₂ and [Ca(OH)₂•Mg(OH)₂]) (IPCC 2006). These factors set

¹⁴ In 2019, 71 operating primary lime facilities in the United States reported to the EPA Greenhouse Gas Reporting Program due to closures.

1 the chemically combined water content to 27 percent for high-calcium hydrated lime, and 30 percent for dolomitic
 2 hydrated lime.

3 The 2006 IPCC Guidelines (Tier 2 method) also recommends accounting for emissions from lime kiln dust (LKD)
 4 through application of a correction factor. LKD is a byproduct of the lime manufacturing process typically not
 5 recycled back to kilns. LKD is a very fine-grained material and is especially useful for applications requiring very
 6 small particle size. Most common LKD applications include soil reclamation and agriculture. Emissions from the
 7 application of lime for agricultural purposes are reported in the Agriculture chapter under 5.5 Liming (CRF Source
 8 Category 3G). Currently, data on annual LKD production is not readily available to develop a country-specific
 9 correction factor. Lime emission estimates were multiplied by a factor of 1.02 to account for emissions from LKD
 10 (IPCC 2006). See the Planned Improvements section associated with efforts to improve uncertainty analysis and
 11 emission estimates associated with LKD.

12 Lime emission estimates were further adjusted to account for the amount of CO₂ captured for use in on-site
 13 processes. All the domestic lime facilities are required to report these data to EPA under its GHGRP. The total
 14 national-level annual amount of CO₂ captured for on-site process use was obtained from EPA’s GHGRP (EPA 2020)
 15 based on reported facility-level data for years 2010 through 2019. The amount of CO₂ captured/recovered for on-
 16 site process use is deducted from the total gross emissions (i.e., from lime production and LKD). The net lime
 17 emissions are presented in Table 4-6 and Table 4-7. GHGRP data on CO₂ removals (i.e., CO₂ captured/recovered)
 18 was available only for 2010 through 2019. Since GHGRP data are not available for 1990 through 2009, IPCC
 19 “splicing” techniques were used as per the 2006 IPCC Guidelines on time-series consistency (IPCC 2006, Volume 1,
 20 Chapter 5).

21 Lime production data by type (i.e., high-calcium and dolomitic quicklime, high-calcium and dolomitic hydrated
 22 lime, and dead-burned dolomite) for 1990 through 2018 (see Table 4-8) were obtained from U.S. Geological Survey
 23 (USGS) Minerals Yearbook (USGS 1992 through 2018) and are compiled by USGS to the nearest ton. The 2019 high-
 24 calcium quicklime and dolomitic quicklime values were estimated using the ratio of the 2018 quicklime values to
 25 the 2019 total values (USGS 2020a). The 2018 values for high-calcium hydrated, dolomitic hydrated, and dead-
 26 burned dolomite were used as proxy for 2019. Natural hydraulic lime, which is produced from CaO and hydraulic
 27 calcium silicates, is not manufactured in the United States (USGS 2018). Total lime production was adjusted to
 28 account for the water content of hydrated lime by converting hydrate to oxide equivalent based on
 29 recommendations from the IPCC and using the water content values for high-calcium hydrated lime and dolomitic
 30 hydrated lime mentioned above, and is presented in

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32 Table 4-9 (IPCC 2006). The CaO and CaO•MgO contents of lime, both 95 percent, were obtained from the IPCC
 33 (IPCC 2006). Since data for the individual lime types (high calcium and dolomitic) were not provided prior to 1997,
 34 total lime production for 1990 through 1996 was calculated according to the three-year distribution from 1997 to
 35 1999.

36 **Table 4-8: High-Calcium- and Dolomitic-Quicklime, High-Calcium- and Dolomitic-Hydrated,**
 37 **and Dead-Burned-Dolomite Lime Production (kt)**

Year	High-Calcium Quicklime	Dolomitic Quicklime	High-Calcium Hydrated	Dolomitic Hydrated	Dead-Burned Dolomite
1990	11,166	2,234	1,781	319	342
2005	14,100	2,990	2,220	474	200
2015	13,100	2,550	2,150	279	189
2016	12,000	2,420	2,350	280	190
2017	12,200	2,650	2,360	276	192
2018	12,400	2,820	2,430	265	197
2019	12,309	2,799	2,430	265	197

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Table 4-9: Adjusted Lime Production (kt)

Year	High-Calcium	Dolomitic
1990	12,466	2,800
2005	15,721	3,522
2015	14,670	2,934
2016	13,716	2,806
2017	13,923	3,035
2018	14,174	3,203
2019	14,083	3,182

Note: Minus water content of hydrated lime.

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

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The uncertainties contained in these estimates can be attributed to slight differences in the chemical composition of lime products and CO₂ recovery rates for on-site process use over the time series. Although the methodology accounts for various formulations of lime, it does not account for the trace impurities found in lime, such as iron oxide, alumina, and silica. Due to differences in the limestone used as a raw material, a rigid specification of lime material is impossible. As a result, few plants produce lime with exactly the same properties.

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In addition, a portion of the CO₂ emitted during lime production will actually be reabsorbed when the lime is consumed, especially at captive lime production facilities. As noted above, lime has many different chemical, industrial, environmental, and construction applications. In many processes, CO₂ reacts with the lime to create calcium carbonate (e.g., water softening). Carbon dioxide reabsorption rates vary, however, depending on the application. For example, 100 percent of the lime used to produce precipitated calcium carbonate reacts with CO₂, whereas most of the lime used in steel making reacts with impurities such as silica, sulfur, and aluminum compounds. Quantifying the amount of CO₂ that is reabsorbed would require a detailed accounting of lime use in the United States and additional information about the associated processes where both the lime and byproduct CO₂ are “reused.” Research conducted thus far has not yielded the necessary information to quantify CO₂ reabsorption rates.¹⁵ Some additional information on the amount of CO₂ consumed on site at lime facilities, however, has been obtained from EPA’s GHGRP.

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In some cases, lime is generated from calcium carbonate byproducts at pulp mills and water treatment plants.¹⁶ The lime generated by these processes is included in the USGS data for commercial lime consumption. In the pulping industry, mostly using the Kraft (sulfate) pulping process, lime is consumed in order to causticize a process liquor (green liquor) composed of sodium carbonate and sodium sulfide. The green liquor results from the dilution of the smelt created by combustion of the black liquor where biogenic carbon (C) is present from the wood. Kraft mills recover the calcium carbonate “mud” after the causticizing operation and calcine it back into lime—thereby generating CO₂—for reuse in the pulping process. Although this re-generation of lime could be considered a lime

¹⁵ Representatives of the National Lime Association estimate that CO₂ reabsorption that occurs from the use of lime may offset as much as a quarter of the CO₂ emissions from calcination (Males 2003).

¹⁶ Some carbide producers may also regenerate lime from their calcium hydroxide byproducts, which does not result in emissions of CO₂. In making calcium carbide, quicklime is mixed with coke and heated in electric furnaces. The regeneration of lime in this process is done using a waste calcium hydroxide (hydrated lime) [CaC₂ + 2H₂O → C₂H₂ + Ca(OH)₂], not calcium carbonate [CaCO₃]. Thus, the calcium hydroxide is heated in the kiln to simply expel the water [Ca(OH)₂ + heat → CaO + H₂O] and no CO₂ is released.

1 manufacturing process, the CO₂ emitted during this process is mostly biogenic in origin and therefore is not
 2 included in the industrial processes totals (Miner and Upton 2002). In accordance with IPCC methodological
 3 guidelines, any such emissions are calculated by accounting for net C fluxes from changes in biogenic C reservoirs
 4 in wooded or crop lands (see the Land Use, Land-Use Change, and Forestry chapter).

5 In the case of water treatment plants, lime is used in the softening process. Some large water treatment plants
 6 may recover their waste calcium carbonate and calcine it into quicklime for reuse in the softening process. Further
 7 research is necessary to determine the degree to which lime recycling is practiced by water treatment plants in the
 8 United States.

9 Another uncertainty is the assumption that calcination emissions for LKD are around 2 percent. The National Lime
 10 Association (NLA) has commented that the estimates of emissions from LKD in the United States could be closer to
 11 6 percent. They also note that additional emissions (approximately 2 percent) may also be generated through
 12 production of other byproducts/wastes (off-spec lime that is not recycled, scrubber sludge) at lime plants (Seeger
 13 2013). Publicly available data on LKD generation rates, total quantities not used in cement production, and types of
 14 other byproducts/wastes produced at lime facilities are limited. NLA compiled and shared historical emissions
 15 information and quantities for some waste products reported by member facilities associated with generation of
 16 total calcined byproducts and LKD, as well as methodology and calculation worksheets that member facilities
 17 complete when reporting. There is uncertainty regarding the availability of data across the time series needed to
 18 generate a representative country-specific LKD factor. Uncertainty of the activity data is also a function of the
 19 reliability and completeness of voluntarily reported plant-level production data. Further research, including
 20 outreach and discussion with NLA, and data is needed to improve understanding of additional calcination
 21 emissions to consider revising the current assumptions that are based on IPCC guidelines. More information can be
 22 found in the Planned Improvements section below.

23 The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-10. Lime CO₂ emissions
 24 for 2018 were estimated to be between 12.9 and 13.5 MMT CO₂ Eq. at the 95 percent confidence level. This
 25 confidence level indicates a range of approximately 2 percent below and 2 percent above the emission estimate of
 26 13.2 MMT CO₂ Eq.

27 **Table 4-10: Approach 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Lime**
 28 **Production (MMT CO₂ Eq. and Percent)**

Source	Gas	2018 Emission Estimate (MMT CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			Lower Bound	Upper Bound	Lower Bound (%)	Upper Bound (%)
Lime Production	CO ₂	13.2	12.9	13.5	-2%	+2%

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

29 Methodological approaches were applied to the entire time series to ensure consistency in emissions from 1990
 30 through 2018. Details on the emission trends through time are described in more detail in the Methodology
 31 section, above.

32 QA/QC and Verification

33 General quality assurance/quality control (QA/QC) procedures were applied consistent with the U.S. Inventory
 34 QA/QC plan, which is in accordance with Volume 1, Chapter 6 of *2006 IPCC Guidelines* as noted in the introduction
 35 of the IPPU chapter (see Annex 8 for more details).

36 More details on the greenhouse gas calculation, monitoring and QA/QC methods associated with reporting on CO₂
 37 captured for onsite use applicable to lime manufacturing facilities can be found under Subpart S (Lime

1 Manufacturing) of the GHGRP regulation (40 CFR Part 98).¹⁷ EPA verifies annual facility-level GHGRP reports
2 through a multi-step process (e.g., combination of electronic checks and manual reviews) to identify potential
3 errors and ensure that data submitted to EPA are accurate, complete, and consistent (EPA 2020).¹⁸ Based on the
4 results of the verification process, EPA follows up with facilities to resolve mistakes that may have occurred. The
5 post-submittals checks are consistent with a number of general and category-specific QC procedures, including:
6 range checks, statistical checks, algorithm checks, and year-to-year checks of reported data and emissions.

7 Recalculations Discussion

8 Recalculations were performed for year 2018 based on updated CO₂ captured for on-site process use data
9 obtained from EPA's GHGRP. Recalculations were performed for years 2015, 2016, 2017, and 2018 based on
10 updated high-calcium and dolomitic quicklime, high-calcium and dolomitic hydrated lime, and dead-burned
11 dolomite production data from 2018 USGS Minerals Yearbook for lime. The updates resulted in less than a 1
12 percent decrease in CO₂ emissions for 2015, 2016, and 2018 and a less than 1 percent increase in CO₂ emissions for
13 2017, compared to the previous Inventory.

14 Planned Improvements

15 EPA plans to review GHGRP emissions and activity data reported to EPA under Subpart S of the GHGRP regulation
16 (40 CFR Part 98), and aggregated activity data on lime production by type in particular. In addition, initial review of
17 data has identified that several facilities use CEMS to report emissions. Under Subpart S, if a facility is using a
18 CEMS, they are required to report combined combustion emissions and process emissions. EPA continues to
19 review how best to incorporate GHGRP and notes that particular attention will be made to also ensuring time-
20 series consistency of the emissions estimates presented in future Inventory reports, consistent with IPCC and
21 UNFCCC guidelines. This is required because the facility-level reporting data from EPA's GHGRP, with the program's
22 initial requirements for reporting of emissions in calendar year 2010, are not available for all inventory years (i.e.,
23 1990 through 2009) as required for this Inventory. In implementing improvements and integration of data from
24 EPA's GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will be
25 relied upon.¹⁹

26 Future improvements involve improving and/or confirming the representativeness of current assumptions
27 associated with emissions from production of LKD and other byproducts/wastes as discussed in the Uncertainty
28 and Time Series Consistency section, per comments from the NLA provided during a prior Public Review comment
29 period for this (i.e., 1990 through 2018) and previous Inventories. EPA met with NLA in summer of 2020 for
30 clarification on data needs and available data and to discuss planned research into GHGRP data. Previously, EPA
31 met with NLA in spring of 2015 to outline specific information required to apply IPCC methods to develop a
32 country-specific correction factor to more accurately estimate emissions from production of LKD. In 2016, NLA
33 compiled and shared historical emissions information reported by member facilities on an annual basis under
34 voluntary reporting initiatives from 2002 through 2011 associated with generation of total calcined byproducts and
35 LKD. Reporting of LKD was only differentiated for the years 2010 and 2011. This emissions information was
36 reported on a voluntary basis consistent with NLA's facility-level reporting protocol, which was also provided to
37 EPA. To reflect information provided by NLA, EPA updated the qualitative description of uncertainty. At the time of
38 this Inventory, this planned improvement is in process and has not been incorporated into this current Inventory
39 report.

¹⁷ See <http://www.ecfr.gov/cgi-bin/text-idx?tpl=/ecfrbrowse/Title40/40cfr98_main_02.tpl>.

¹⁸ See <https://www.epa.gov/sites/production/files/2015-07/documents/ghgrp_verification_factsheet.pdf>.

¹⁹ See <http://www.ipcc-nggip.iges.or.jp/public/tb/TFI_Technical_Bulletin_1.pdf>.

4.3 Glass Production (CRF Source Category 2A3)

Glass production is an energy and raw-material intensive process that results in the generation of carbon dioxide (CO₂) from both the energy consumed in making glass and the glass production process itself. Emissions from fuels consumed for energy purposes during the production of glass are included in the Energy sector.

Glass production employs a variety of raw materials in a glass-batch. These include formers, fluxes, stabilizers, and sometimes colorants. The major raw materials (i.e., fluxes and stabilizers) that emit process-related CO₂ emissions during the glass melting process are limestone, dolomite, and soda ash. The main former in all types of glass is silica (SiO₂). Other major formers in glass include feldspar and boric acid (i.e., borax). Fluxes are added to lower the temperature at which the batch melts. Most commonly used flux materials are soda ash (sodium carbonate, Na₂CO₃) and potash (potassium carbonate, K₂O). Stabilizers are used to make glass more chemically stable and to keep the finished glass from dissolving and/or falling apart. Commonly used stabilizing agents in glass production are limestone (CaCO₃), dolomite (CaCO₃MgCO₃), alumina (Al₂O₃), magnesia (MgO), barium carbonate (BaCO₃), strontium carbonate (SrCO₃), lithium carbonate (Li₂CO₃), and zirconia (ZrO₂) (OIT 2002). Glass makers also use a certain amount of recycled scrap glass (cullet), which comes from in-house return of glassware broken in the process or other glass spillage or retention, such as recycling or from cullet broker services.

The raw materials (primarily soda ash, limestone, and dolomite) release CO₂ emissions in a complex high-temperature chemical reaction during the glass melting process. This process is not directly comparable to the calcination process used in lime manufacturing, cement manufacturing, and process uses of carbonates (i.e., limestone/dolomite use) but has the same net effect in terms of CO₂ emissions (IPCC 2006).

The U.S. glass industry can be divided into four main categories: containers, flat (window) glass, fiber glass, and specialty glass. The majority of commercial glass produced is container and flat glass (EPA 2009). The United States is one of the major global exporters of glass. Domestically, demand comes mainly from the construction, auto, bottling, and container industries. There are more than 1,500 companies that manufacture glass in the United States, with the largest being Corning, Guardian Industries, Owens-Illinois, and PPG Industries.²⁰

In 2019, 2,220 kilotons of soda ash and 817 kilotons of limestone were consumed for glass production (USGS 2020; USGS 2020a). Dolomite consumption data for glass manufacturing was reported to be zero for 2019. Use of limestone and soda ash in glass production resulted in aggregate CO₂ emissions of 1.3 MMT CO₂ Eq. (1,280 kt) (see Table 4-11). Overall, emissions have decreased 17 percent from 1990 through 2019.

Emissions in 2019 decreased approximately 2 percent from 2018 levels while, in general, emissions from glass production have remained relatively constant over the time series with some fluctuations since 1990. In general, these fluctuations were related to the behavior of the export market and the U.S. economy. Specifically, the extended downturn in residential and commercial construction and automotive industries between 2008 and 2010 resulted in reduced consumption of glass products, causing a drop in global demand for limestone/dolomite and soda ash and resulting in emissions. Furthermore, the glass container sector is one of the leading soda ash consuming sectors in the United States. Some commercial food and beverage package manufacturers are shifting from glass containers towards lighter and more cost-effective polyethylene terephthalate (PET) based containers, putting downward pressure on domestic consumption of soda ash (USGS 1995 through 2015b).

²⁰ Excerpt from Glass & Glass Product Manufacturing Industry Profile, First Research. Available online at: <<http://www.firstresearch.com/Industry-Research/Glass-and-Glass-Product-Manufacturing.html>>.

1 **Table 4-11: CO₂ Emissions from Glass Production (MMT CO₂ Eq. and kt)**

Year	MMT CO ₂ Eq.	kt
1990	1.5	1,535
2005	1.9	1,928
2015	1.3	1,299
2016	1.3	1,249
2017	1.3	1,296
2018	1.3	1,306
2019	1.3	1,280

Note: Totals may not sum due to independent rounding.

2 Methodology

3 Carbon dioxide emissions were calculated based on the 2006 IPCC Guidelines Tier 3 method by multiplying the
 4 quantity of input carbonates (limestone, dolomite, and soda ash) by the carbonate-based emission factor (in
 5 metric tons CO₂/metric ton carbonate): limestone, 0.43971; dolomite, 0.47732; and soda ash, 0.41492.

6 In 1991, the U.S. Bureau of Mines, now known as the U.S. Geological Survey (USGS), began compiling production
 7 and end use information through surveys of crushed stone manufacturers. Each year, limestone and dolomite
 8 make up approximately 70% of the total crushed stone manufactured in the United States (USGS 1995 through
 9 2016a). Crushed stone manufacturers provided different levels of detail in the survey responses, so information
 10 was divided into three categories: (1) production by end-use, as reported by manufacturers (i.e., “specified”
 11 production); (2) production reported by manufacturers without end-uses specified (i.e., “unspecified-reported”
 12 production); and (3) estimated additional production by manufacturers who did not respond to the survey (i.e.,
 13 “unspecified-estimated” production).

14 The “specified” production portion of the report provides limestone and dolomite consumption for glass
 15 manufacturing. Large quantities of limestone and dolomite consumption are reported under the categories
 16 “unspecified–reported” and “unspecified–estimated” as well, and a portion of this consumption is believed to be
 17 limestone or dolomite used for glass manufacturing. The quantities listed under both “unspecified” categories
 18 were allocated to glass manufacturing according to the percentage of “specified” limestone or dolomite consumed
 19 for glass manufacturing end-use for that year.²¹

20 During 1990 and 1992, the U.S. Bureau of Mines did not conduct a detailed survey of limestone and dolomite
 21 consumption by end-use. Therefore, data on consumption by end use for 1990 was estimated by applying the 1991
 22 ratios of total limestone and dolomite consumption by end use to total 1990 limestone and dolomite consumption
 23 values. Similarly, the 1992 consumption figures were approximated by applying an average of the 1991 and 1993
 24 ratios of total limestone and dolomite consumption by end use to the 1992 total limestone and dolomite
 25 consumption values.

26 For 1990 through 1993, consumption data of limestone and dolomite used for glass manufacturing were obtained
 27 from the U.S. Bureau of Mines (1991 and 1993a), For 1994 through 2018, consumption data of limestone and
 28 dolomite used for glass manufacturing were obtained from the USGS *Minerals Yearbook: Crushed Stone Annual
 29 Report* (1995 through 2016a), and 2018 preliminary data from the USGS Crushed Stone Commodity Expert (Willett
 30 2020a). The total limestone and dolomite used for glass manufacturing was determined in the same manner as
 31 described for 1991 above. For 2019, consumption data for limestone and dolomite used for glass manufacturing
 32 were not available at the time of publication, so 2018 values were used as proxy.

²¹ This approach was recommended by USGS.

1 Each year the USGS withholds data on certain limestone and dolomite end-uses due to confidentiality agreements
 2 regarding company proprietary data. For the purposes of this analysis, emissive end-uses that contained withheld
 3 data were estimated using one of the following techniques: (1) the value for all the withheld data points for
 4 limestone or dolomite use was distributed evenly to all withheld end-uses; or (2) the average percent of total
 5 limestone or dolomite for the withheld end-use in the preceding and succeeding years.

6 For 1990 through 2019, consumption data for soda ash used for glass manufacturing were obtained from the U.S.
 7 Bureau of Mines (1991 and 1993a), the *USGS Minerals Yearbook: Soda Ash Annual Report* (1995 through 2015b)
 8 (USGS 1995 through 2015b), and *USGS Mineral Industry Surveys for Soda Ash* in April 2020 (USGS 2020).

9 Based on the 2019 reported data, the estimated distribution of soda ash consumption for glass production
 10 compared to total domestic soda ash consumption is 47 percent (USGS 2020). Emissions from soda ash production
 11 are reported in 4.12 Soda Ash Production (CRF Source Category 2B7).

12 **Table 4-12: Limestone, Dolomite, and Soda Ash Consumption Used in Glass Production (kt)**

Activity	1990	2005	2015	2016	2017	2018	2019
Limestone	430	920	699	472	720	818	817
Dolomite	59	541	0	0	0	0	0
Soda Ash	3,177	3,050	2,390	2,510	2,360	2,280	2,220
Total	3,666	4,511	3,089	2,982	3,080	3,098	3,037

13 Uncertainty and Time-Series Consistency – TO BE UPDATED

14 The uncertainty levels presented in this section arise in part due to variations in the chemical composition of
 15 limestone used in glass production. In addition to calcium carbonate, limestone may contain smaller amounts of
 16 magnesia, silica, and sulfur, among other minerals (potassium carbonate, strontium carbonate and barium
 17 carbonate, and dead burned dolomite). Similarly, the quality of the limestone (and mix of carbonates) used for
 18 glass manufacturing will depend on the type of glass being manufactured.

19 The estimates below also account for uncertainty associated with activity data. Large fluctuations in reported
 20 consumption exist, reflecting year-to-year changes in the number of survey responders. The uncertainty resulting
 21 from a shifting survey population is exacerbated by the gaps in the time series of reports. The accuracy of
 22 distribution by end use is also uncertain because this value is reported by the manufacturer of the input
 23 carbonates (limestone, dolomite and soda ash) and not the end user. For 2018, there has been no reported
 24 consumption of dolomite for glass manufacturing. These data have been reported to USGS by dolomite
 25 manufacturers and not end-users (i.e., glass manufacturers). There is a high uncertainty associated with this
 26 estimate, as dolomite is a major raw material consumed in glass production. Additionally, there is significant
 27 inherent uncertainty associated with estimating withheld data points for specific end uses of limestone and
 28 dolomite. The uncertainty of the estimates for limestone and dolomite used in glass making is especially high.
 29 Lastly, much of the limestone consumed in the United States is reported as “other unspecified uses;” therefore, it
 30 is difficult to accurately allocate this unspecified quantity to the correct end-uses. Further research is needed into
 31 alternate and more complete sources of data on carbonate-based raw material consumption by the glass industry.

32 The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-13. In 2018, glass
 33 production CO₂ emissions were estimated to be between 1.2 and 1.3 MMT CO₂ Eq. at the 95 percent confidence
 34 level. This indicates a range of approximately 4 percent below and 5 percent above the emission estimate of 1.3
 35 MMT CO₂ Eq.

36 **Table 4-13: Approach 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Glass**
 37 **Production (MMT CO₂ Eq. and Percent)**

Source	Gas	2019 Emission Estimate (MMT CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			(MMT CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound

Glass Production	CO ₂	1.3	1.2	1.3	-4%	+5%
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^a Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

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

4 QA/QC and Verification

5 General quality assurance/quality control (QA/QC) procedures were applied consistent with the U.S. Inventory
 6 QA/QC plan, which is in accordance with Volume 1, Chapter 6 of *2006 IPCC Guidelines* as described in the
 7 introduction of the IPPU chapter (see Annex 8 for more details).

8 Recalculations Discussion

9 For the current Inventory, updated USGS data on limestone and dolomite consumption became available for 2016
 10 and 2018. The revised values used in the current Inventory resulted in updated emissions estimates for the years
 11 2016 (increase of 0.6 percent) and 2018 (increase of 1.7 percent).

12 Planned Improvements

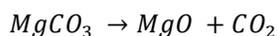
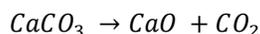
13 As noted in the prior annual publications of this report, current publicly available activity data shows consumption
 14 of only limestone and soda ash for glass manufacturing. While limestone and soda ash are the predominant
 15 carbonates used in glass manufacturing, other carbonates are also consumed for glass manufacturing but in
 16 smaller quantities. EPA has initiated review of available activity data on carbonate consumption by type in the
 17 glass industry, reported annually since 2010 from EPA's Greenhouse Gas Reporting Program (GHGRP) as well as in
 18 USGS publications. This is a long-term planned improvement.

19 EPA has initiated review of GHGRP data to help understand the completeness of emission estimates and facilitate
 20 category-specific QC per Volume 1 of the *2006 IPCC Guidelines* for the Glass Production source category. GHGRP
 21 has an emission threshold for reporting from this industry, so the assessment will also consider the completeness
 22 of carbonate consumption data for glass production in the United States. Particular attention will be made to
 23 ensure time-series consistency of the emissions estimates presented in future Inventory reports, consistent with
 24 IPCC and UNFCCC guidelines. This is required as the facility-level reporting data from EPA's GHGRP, with the
 25 program's initial requirements for reporting of emissions in calendar year 2010, are not available for all inventory
 26 years (i.e., 1990 through 2009) as required for this Inventory. In implementing improvements and integration of
 27 data from GHGRP, EPA will rely on the latest guidance from the IPCC on the use of facility-level data in national
 28 inventories.²² These planned improvements are ongoing, and EPA may also initiate research into other sources of
 29 activity data for carbonate consumption by the glass industry.

²² See <http://www.ipcc-nggip.iges.or.jp/public/tb/TFI_Technical_Bulletin_1.pdf>.

4.4 Other Process Uses of Carbonates (CRF Source Category 2A4)

Limestone (CaCO_3), dolomite ($\text{CaCO}_3\text{MgCO}_3$),²³ and other carbonates such as soda ash, magnesite, and siderite are basic materials used by a wide variety of industries, including construction, agriculture, chemical, metallurgy, glass production, and environmental pollution control. This section addresses only limestone, dolomite, and soda ash use. For industrial applications, carbonates such as limestone and dolomite are heated sufficiently enough to calcine the material and generate CO_2 as a byproduct.



Examples of such applications include limestone used as a flux or purifier in metallurgical furnaces, as a sorbent in flue gas desulfurization (FGD) systems for utility and industrial plants, and as a raw material for the production of glass, lime, and cement. Emissions from limestone and dolomite used in other process sectors, such as cement, lime, glass production, and iron and steel, are excluded from the Other Process Uses of Carbonates category and reported under their respective source categories (e.g., Section 4.3, Glass Production). Emissions from soda ash production are reported under Section 4.12 Soda Ash Production (CRF Source Category 2B7). Emissions from soda ash consumption associated with glass manufacturing are reported under Section 4.3 Glass Production (CRF Source Category 2A3). Emissions from the use of limestone and dolomite in liming of agricultural soils are included in the Agriculture chapter under Liming (CRF Source Category 3G). Emissions from fuels consumed for energy purposes during these processes are accounted for in the Energy chapter under Section 3.1 Fossil Fuel Combustion (CRF Source Category 1A).

Limestone and dolomite are widely distributed throughout the world in deposits of varying sizes and degrees of purity. Large deposits of limestone occur in nearly every state in the United States, and significant quantities are extracted for industrial applications. In 2016, the leading limestone producing states were Texas, Florida, Missouri, Ohio, and Pennsylvania, which contributed 44 percent of the total U.S. output (USGS 2020a). Dolomite deposits are found in the United States, Canada, Mexico, Europe, Africa, and Brazil. In the United States, the leading dolomite producing states are Pennsylvania, New York, and Utah which currently contribute more than a third of the total U.S. output (USGS 2020a). Internationally, two types of soda ash are produced: natural and synthetic. In 2017, 93 percent of the global soda ash production came from China, the United States, Russia, Germany, India, Turkey, Poland, and France. The United States only produces natural soda ash and only in two states: Wyoming and California (USGS 2020b).

In 2019, 13,779 kilotons of limestone, 2,066 kt of dolomite, and 2,497 kt of soda ash were consumed for these emissive applications, excluding glass manufacturing (Willett 2020, USGS 2020b). Usage of limestone, dolomite and soda ash resulted in aggregate CO_2 emissions of 7.5 MMT CO_2 Eq. (7,457 kt) (see Table 4-14 and Table 4-15). Limestone and dolomite consumption data were not available for 2019, so 2018 data were used as a proxy. The 2018 and 2019 emissions decreased 25 percent compared to 2017, primarily as a result of decreased limestone consumption attributed to sulfur oxide removal usage for FGD systems. Overall emissions have increased 18 percent from 1990 through 2019.

²³ Limestone and dolomite are collectively referred to as limestone by the industry, and intermediate varieties are seldom distinguished.

1 **Table 4-14: CO₂ Emissions from Other Process Uses of Carbonates (MMT CO₂ Eq.)**

Year	Flux Stone	FGD	Magnesium Production	Soda Ash Consumption ^a	Other Miscellaneous Uses ^b	Total
1990	2.6	1.4	0.1	1.4	0.8	6.3
2005	2.6	3.0	0.0	1.3	0.7	7.6
2015	2.9	7.3	0.0	1.1	0.9	12.2
2016	2.6	6.2	0.0	1.1	1.1	11.0
2017	2.4	5.6	0.0	1.1	0.8	9.9
2018	2.8	2.2	0.0	1.1	1.4	7.5
2019	2.8	2.2	0.0	1.0	1.4	7.5

Note: Totals may not sum due to independent rounding.

^a Soda ash consumption not associated with glass manufacturing.

^b "Other miscellaneous uses" include chemical stone, mine dusting or acid water treatment, acid neutralization, and sugar refining.

2 **Table 4-15: CO₂ Emissions from Other Process Uses of Carbonates (kt)**

Year	Flux Stone	FGD	Magnesium Production	Soda Ash Consumption ^a	Other Miscellaneous Uses ^b	Total
1990	2,592	1,432	64	1,390	819	6,297
2005	2,649	2,973	0	1,305	718	7,644
2015	2,901	7,335	0	1,075	871	12,182
2016	2,585	6,164	0	1,082	1,140	10,972
2017	2,441	5,598	0	1,058	835	9,933
2018	2,800	2,233	0	1,069	1,367	7,469
2019	2,821	2,233	0	1,036	1,367	7,457

Note: Totals may not sum due to independent rounding

^a Soda ash consumption not associated with glass manufacturing.

^b "Other miscellaneous uses" include chemical stone, mine dusting or acid water treatment, acid neutralization, and sugar refining.

3 Methodology

4 Carbon dioxide emissions were calculated based on the *2006 IPCC Guidelines* Tier 2 method by multiplying the
 5 quantity of limestone or dolomite consumed by the emission factor for limestone or dolomite calcination,
 6 respectively: 0.43971 metric ton CO₂/metric ton carbonate for limestone and 0.47732 metric ton CO₂/metric ton
 7 carbonate for dolomite.²⁴ This methodology was used for flux stone, flue gas desulfurization systems, chemical
 8 stone, mine dusting or acid water treatment, acid neutralization, and sugar refining. Flux stone used during the
 9 production of iron and steel was deducted from the Other Process Uses of Carbonates source category estimate
 10 and attributed to the Iron and Steel Production source category estimate. Similarly, limestone and dolomite
 11 consumption for glass manufacturing, cement, and lime manufacturing are excluded from this category and
 12 attributed to their respective categories.

13 Historically, the production of magnesium metal was the only other significant use of limestone and dolomite that
 14 produced CO₂ emissions. At the end of 2001, the sole magnesium production plant operating in the United States

²⁴ *2006 IPCC Guidelines*, Volume 3: Chapter 2, Table 2.1.

1 that produced magnesium metal using a dolomitic process that resulted in the release of CO₂ emissions ceased its
 2 operations (USGS 1995b through 2020).

3 Consumption data for 1990 through 2018 of limestone and dolomite used for flux stone, flue gas desulfurization
 4 systems, chemical stone, mine dusting or acid water treatment, acid neutralization, and sugar refining (see Table
 5 4-16) were obtained from the U.S. Geological Survey (USGS) *Minerals Yearbook: Crushed Stone Annual Report*
 6 (1995a through 2017, 2020a, 2020c), preliminary data for 2018 from USGS Crushed Stone Commodity Expert
 7 (Willett 2020), American Iron and Steel Institute limestone and dolomite consumption data (AISI 2018 through
 8 2020), and the U.S. Bureau of Mines (1991 and 1993a), which are reported to the nearest ton. For 2019, no data
 9 on limestone and dolomite consumption were available at the time of publication, so 2018 values were used as a
 10 proxy for these values. The production capacity data for 1990 through 2001 of dolomitic magnesium metal also
 11 came from the USGS (1995b through 2002) and the U.S. Bureau of Mines (1990 through 1993b). During 1990 and
 12 1992, the USGS did not conduct a detailed survey of limestone and dolomite consumption by end-use. Therefore,
 13 data on consumption by end use for 1990 was estimated by applying the 1991 ratios of total limestone and
 14 dolomite consumption by end use to total 1990 limestone and dolomite consumption values. Similarly, the 1992
 15 consumption figures were approximated by applying an average of the 1991 and 1993 ratios of total limestone and
 16 dolomite use by end uses to the 1992 total values.

17 In 1991, the U.S. Bureau of Mines, now known as the USGS, began compiling production and end use information
 18 through surveys of crushed stone manufacturers. Manufacturers, provided different levels of detail in survey
 19 responses, so information was divided into three categories: (1) production by end-use, as reported by
 20 manufacturers (i.e., “specified” production); (2) production reported by manufacturers without end-uses specified
 21 (i.e., “unspecified-reported” production); and (3) estimated additional production by manufacturers who did not
 22 respond to the survey (i.e., “unspecified-estimated” production). Additionally, each year the USGS withholds data
 23 on certain limestone and dolomite end-uses due to confidentiality agreements regarding company proprietary
 24 data. For the purposes of this analysis, emissive end-uses that contained withheld data were estimated using one
 25 of the following techniques: (1) the value for all the withheld data points for limestone or dolomite use was
 26 distributed evenly to all withheld end-uses; (2) the average percent of total limestone or dolomite for the withheld
 27 end-use in the preceding and succeeding years; or (3) the average fraction of total limestone or dolomite for the
 28 end-use over the entire time period.

29 There is a large quantity of crushed stone reported to the USGS under the category “unspecified uses.” A portion
 30 of this consumption is believed to be limestone or dolomite used for emissive end uses. The quantity listed for
 31 “unspecified uses” was, therefore, allocated to all other reported end-uses according to each end-use’s fraction of
 32 total consumption in that year.²⁵

33 **Table 4-16: Limestone and Dolomite Consumption (kt)**

Activity	1990	2005	2015	2016	2017	2018	2019
Flux Stone	6,737	7,022	7,834	7,092	6,853	7,658	7,658
Limestone	5,804	3,165	4,590	4,118	4,920	5,603	5,603
Dolomite	933	3,857	3,244	2,973	1,933	2,055	2,055
FGD	3,258	6,761	16,680	14,019	12,732	5,078	5,078
Other Miscellaneous Uses	1,835	1,632	1,982	2,592	1,900	3,108	3,108
Total	11,830	15,415	26,496	23,703	21,484	15,845	15,845

34 Once produced, most soda ash is consumed in chemical production, with minor amounts used in soap production,
 35 pulp and paper, flue gas desulfurization, and water treatment (excluding soda ash consumption for glass
 36 manufacturing). As soda ash is consumed for these purposes, additional CO₂ is usually emitted. In these
 37 applications, it is assumed that one mole of carbon is released for every mole of soda ash used. Thus,
 38 approximately 0.113 metric tons of carbon (or 0.415 metric tons of CO₂) are released for every metric ton of soda
 39 ash consumed. The activity data for soda ash consumption for 1990 to 2019 (see Table 4-17) were obtained from

²⁵ This approach was recommended by USGS, the data collection agency.

1 the U.S. Geological Survey (USGS) *Minerals Yearbook for Soda Ash* (1994 through 2015b) and USGS *Mineral*
 2 *Industry Surveys for Soda Ash* (USGS 2017a, 2018, 2019, 2020). Soda ash consumption data were collected by the
 3 USGS from voluntary surveys of the U.S. soda ash industry.

4 **Table 4-17: Soda Ash Consumption Not Associated with Glass Manufacturing (kt)**

Activity	1990	2005	2015	2016	2017	2018	2019
Soda Ash ^a	3,351	3,144	2,592	2,608	2,550	2,576	2,497
Total	3,351	3,144	2,592	2,608	2,550	2,576	2,497

^a Soda ash consumption is sales reported by producers which exclude imports. Historically, imported soda ash is less than 1 percent of the total U.S. consumption (Kostick 2012).

5 **Uncertainty and Time-Series Consistency – TO BE UPDATED**

6 The uncertainty levels presented in this section account for uncertainty associated with activity data. Data on
 7 limestone and dolomite consumption are collected by USGS through voluntary national surveys. USGS contacts the
 8 mines (i.e., producers of various types of crushed stone) for annual sales data. Data on other carbonate
 9 consumption are not readily available. The producers report the annual quantity sold to various end-users and
 10 industry types. USGS estimates the historical response rate for the crushed stone survey to be approximately 70
 11 percent, and the rest is estimated by USGS. Large fluctuations in reported consumption exist, reflecting year-to-
 12 year changes in the number of survey responders. The uncertainty resulting from a shifting survey population is
 13 exacerbated by the gaps in the time series of reports. The accuracy of distribution by end use is also uncertain
 14 because this value is reported by the producer/mines and not the end user. Additionally, there is significant
 15 inherent uncertainty associated with estimating withheld data points for specific end uses of limestone and
 16 dolomite. Lastly, much of the limestone consumed in the United States is reported as “other unspecified uses;”
 17 therefore, it is difficult to accurately allocate this unspecified quantity to the correct end-uses. This year, EPA
 18 reinitiated dialogue with the USGS National Minerals Information Center Crushed Stone commodity expert to
 19 assess the current uncertainty ranges associated with the limestone and dolomite consumption data compiled and
 20 published by USGS. During this discussion, the expert confirmed that EPA’s range of uncertainty was still
 21 reasonable (Willett 2017).

22 Uncertainty in the estimates also arises in part due to variations in the chemical composition of limestone. In
 23 addition to calcium carbonate, limestone may contain smaller amounts of magnesia, silica, and sulfur, among
 24 other minerals. The exact specifications for limestone or dolomite used as flux stone vary with the
 25 pyrometallurgical process and the kind of ore processed.

26 For emissions from soda ash consumption, the primary source of uncertainty results from the fact that these
 27 emissions are dependent upon the type of processing employed by each end-use. Specific emission factors for
 28 each end-use are not available, so a Tier 1 default emission factor is used for all end uses. Therefore, there is
 29 uncertainty surrounding the emission factors from the consumption of soda ash. Additional uncertainty comes
 30 from the reported consumption and allocation of consumption within sectors that is collected on a quarterly basis
 31 by the USGS. Efforts have been made to categorize company sales within the correct end-use sector.

32 The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-18. Carbon dioxide
 33 emissions from other process uses of carbonates in 2018 were estimated to be between 8.9 and 11.4 MMT CO₂ Eq.
 34 at the 95 percent confidence level. This indicates a range of approximately 11 percent below and 14 percent above
 35 the emission estimate of 9.4 MMT CO₂ Eq.

Table 4-18: Approach 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Other Process Uses of Carbonates (MMT CO₂ Eq. and Percent)

Source	Gas	2018 Emission Estimate (MMT CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			(MMT CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Other Process Uses of Carbonates	CO ₂	10.0	8.9	11.4	-11%	+14%

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

Methodological approaches were applied to the entire time series to ensure consistency in emissions from 1990 through 2018. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

General quality assurance/quality control (QA/QC) procedures were applied consistent with the U.S. Inventory QA/QC plan, which is in accordance with Volume 1, Chapter 6 of *2006 IPCC Guidelines* as described in the introduction of the IPPU chapter (see Annex 8 for more details).

Recalculations Discussion

For the current Inventory, updated USGS data on limestone and dolomite consumption was available for 2016, 2017, and 2018, resulting in updated emissions estimates for those years. Compared to the previous Inventory, emissions for 2016 increased by 4 percent (467 kt CO₂ Eq.), decreased by less than 1 percent (2 kt CO₂ Eq.) for 2017, and decreased by 25 percent (2,485 kt CO₂ Eq.) for 2018.

Planned Improvements

In response to comments received during previous Inventory reports from the UNFCCC, EPA has inquired to the availability of ceramics and non-metallurgical magnesia data. The USGS notes that this data is not currently reported by survey respondents. EPA continues to conduct outreach with other entities, but at this time, the research has not yielded any alternative data on national levels of carbonates. This improvement remains ongoing, and EPA plans to continue to update this Planned Improvements section in future reports as more information becomes available.

EPA also plans to continue dialogue with USGS to assess uncertainty ranges for activity data used to estimate emissions from other process use of carbonates. This planned improvement is currently planned as a medium-term improvement.

4.5 Ammonia Production (CRF Source Category 2B1)

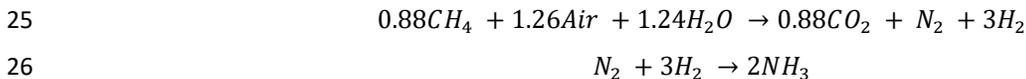
Emissions of carbon dioxide (CO₂) occur during the production of synthetic ammonia (NH₃), primarily through the use of natural gas, petroleum coke, or naphtha as a feedstock. The natural gas-, naphtha-, and petroleum coke-based processes produce CO₂ and hydrogen (H₂), the latter of which is used in the production of ammonia. The

1 brine electrolysis process for production of ammonia does not lead to process-based CO₂ emissions. Due to
2 national circumstances, emissions from fuels consumed for energy purposes during the production of ammonia
3 are accounted for in the Energy chapter. More information on this approach can be found in the Methodology
4 section below.

5 Ammonia production requires a source of nitrogen (N) and hydrogen (H). Nitrogen is obtained from air through
6 liquid air distillation or an oxidative process where air is burnt and the residual nitrogen is recovered. In the United
7 States, the majority of ammonia is produced using a natural gas feedstock as the hydrogen source; however, one
8 synthetic ammonia production plant located in Kansas is producing ammonia from petroleum coke feedstock. In
9 some U.S. plants, some of the CO₂ produced by the process is captured and used to produce urea rather than
10 being emitted to the atmosphere. In 2019, there were 16 companies operating 35 ammonia producing facilities in
11 16 states. Approximately 60 percent of domestic ammonia production capacity is concentrated in the states of
12 Louisiana, Oklahoma, and Texas (USGS 2020).

13 There are five principal process steps in synthetic ammonia production from natural gas feedstock. The primary
14 reforming step converts methane (CH₄) to CO₂, carbon monoxide (CO), and hydrogen (H₂) in the presence of a
15 catalyst. Only 30 to 40 percent of the CH₄ feedstock to the primary reformer is converted to CO and CO₂ in this
16 step of the process. The secondary reforming step converts the remaining CH₄ feedstock to CO and CO₂. The CO in
17 the process gas from the secondary reforming step (representing approximately 15 percent of the process gas) is
18 converted to CO₂ in the presence of a catalyst, water, and air in the shift conversion step. Carbon dioxide is
19 removed from the process gas by the shift conversion process, and the H₂ is combined with the nitrogen (N₂) gas in
20 the process gas during the ammonia synthesis step to produce ammonia. The CO₂ is included in a waste gas stream
21 with other process impurities and is absorbed by a scrubber solution. In regenerating the scrubber solution, CO₂ is
22 released from the solution.

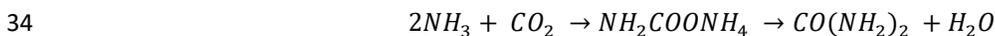
23 The conversion process for conventional steam reforming of CH₄, including the primary and secondary reforming
24 and the shift conversion processes, is approximately as follows:



27 To produce synthetic ammonia from petroleum coke, the petroleum coke is gasified and converted to CO₂ and H₂.
28 These gases are separated, and the H₂ is used as a feedstock to the ammonia production process, where it is
29 reacted with N₂ to form ammonia.

30 Not all of the CO₂ produced during the production of ammonia is emitted directly to the atmosphere. Some of the
31 ammonia and some of the CO₂ produced by the synthetic ammonia process are used as raw materials in the
32 production of urea [CO(NH₂)₂], which has a variety of agricultural and industrial applications.

33 The chemical reaction that produces urea is:



35 Only the CO₂ emitted directly to the atmosphere from the synthetic ammonia production process is accounted for
36 in determining emissions from ammonia production. The CO₂ that is captured during the ammonia production
37 process and used to produce urea does not contribute to the CO₂ emission estimates for ammonia production
38 presented in this section. Instead, CO₂ emissions resulting from the consumption of urea are attributed to the urea
39 consumption or urea application source category (under the assumption that the carbon stored in the urea during
40 its manufacture is released into the environment during its consumption or application). Emissions of CO₂ resulting
41 from agricultural applications of urea are accounted for in the Agriculture chapter. Previously, these emission
42 estimates from the agricultural application of urea were accounted for in the Section 6.4 Cropland Remaining
43 Cropland (CRF Category 4B1) of the Land Use, Land Use Change, and Forestry chapter. Emissions of CO₂ resulting
44 from non-agricultural applications of urea (e.g., use as a feedstock in chemical production processes) are
45 accounted for in Section 4.6 Urea Consumption for Non-Agricultural Purposes of this chapter.

46 Total emissions of CO₂ from ammonia production in 2019 were 12.3 MMT CO₂ Eq. (12,272 kt), and are summarized
47 in Table 4-19 and Table 4-20. Ammonia production relies on natural gas as both a feedstock and a fuel, and as

1 such, market fluctuations and volatility in natural gas prices affect the production of ammonia. Since 1990,
 2 emissions from ammonia production have decreased by about 6 percent. Emissions in 2019 have increased by less
 3 than 1 percent from the 2018 levels. Emissions from ammonia production have increased steadily since 2016, due
 4 to the addition of new ammonia production facilities and new production units at existing facilities in 2016, 2017,
 5 and 2018. Agriculture continues to drive demand for nitrogen fertilizers and the need for new ammonia
 6 production capacity (USGS 2020).

7 **Table 4-19: CO₂ Emissions from Ammonia Production (MMT CO₂ Eq.)**

Source	1990	2005	2015	2016	2017	2018	2019
Ammonia Production	13.0	9.2	10.6	10.2	11.1	12.2	12.3
Total	13.0	9.2	10.6	10.2	11.1	12.2	12.3

8 **Table 4-20: CO₂ Emissions from Ammonia Production (kt)**

Source	1990	2005	2015	2016	2017	2018	2019
Ammonia Production	13,047	9,177	10,616	10,245	11,112	12,163	12,272
Total	13,047	9,177	10,616	10,245	11,112	12,163	12,272

9 Methodology

10 For this Inventory, CO₂ emissions from the production of synthetic ammonia from natural gas feedstock are
 11 estimated using a country-specific approach modified from the *2006 IPCC Guidelines* (IPCC 2006) Tier 1 and 2
 12 methods. In the country-specific approach, emissions are not based on total fuel requirement per the *2006 IPCC*
 13 *Guidelines* due to data disaggregation limitations of energy statistics provided by the Energy Information
 14 Administration (EIA). Data on total fuel use (including fuel used for ammonia feedstock and fuel used for energy)
 15 for ammonia production are not known in the U.S. EIA does not provide data broken out by industrial category,
 16 only at the broad industry sector level. To estimate emissions, a country-specific emission factor is developed and
 17 applied to national ammonia production to estimate ammonia-production emissions from feedstock fuel use.
 18 Emissions from fuel used for energy at ammonia plants are included in the overall EIA Industrial sector energy use
 19 and accounted for in the Energy Chapter. The method uses a CO₂ emission factor published by the European
 20 Fertilizer Manufacturers Association (EFMA) that is based on natural gas-based ammonia production technologies
 21 that are similar to those employed in the United States. The country-specific approach applied is compatible with
 22 the *2006 IPCC Guidelines* as it is based on the same scientific approach that the carbon in the fuel used to produce
 23 ammonia is released as CO₂. This CO₂ emission factor of 1.2 metric tons CO₂/metric ton NH₃ (EFMA 2000a) is
 24 applied to the percent of total annual domestic ammonia production from natural gas feedstock.

25 The emission factor of 1.2 metric tons CO₂ per metric ton NH₃ for production of ammonia from natural gas
 26 feedstock was taken from the EFMA Best Available Techniques publication, *Production of Ammonia* (EFMA 2000a).
 27 The EFMA reported an emission factor range of 1.15 to 1.30 metric tons CO₂ per metric ton NH₃, with 1.2 metric
 28 tons CO₂ per metric ton NH₃ as a typical value (EFMA 2000a). Technologies (e.g., catalytic reforming process, etc.)
 29 associated with this factor are found to closely resemble those employed in the United States for use of natural gas
 30 as a feedstock. The EFMA reference also indicates that more than 99 percent of the CH₄ feedstock to the catalytic
 31 reforming process is ultimately converted to CO₂.

32 Emissions of CO₂ from ammonia production are then adjusted to account for the use of some of the CO₂ produced
 33 from ammonia production as a raw material in the production of urea. The CO₂ emissions reported for ammonia
 34 production are reduced by a factor of 0.733 multiplied by total annual domestic urea production. This corresponds
 35 to a stoichiometric CO₂/urea factor of 44/60, assuming complete conversion of ammonia (NH₃) and CO₂ to urea
 36 (IPCC 2006; EFMA 2000b).

37 All synthetic ammonia production and subsequent urea production are assumed to be from the same process—
 38 conventional catalytic reforming of natural gas feedstock, with the exception of ammonia production from

1 petroleum coke feedstock at one plant located in Kansas. Annual ammonia and urea production are shown in
 2 Table 4-21.

3 The implied CO₂ emission factor for total ammonia production is a combination of the emission factors for
 4 ammonia production from natural gas and from petroleum coke. Changes in the relative production of ammonia
 5 from natural gas and petroleum coke will impact overall emissions and emissions per ton of total ammonia
 6 produced. For example, between 2000 and 2001 there were increases in the amount of ammonia produced from
 7 petroleum coke which caused increases in the implied emission factor across those years.

8 In prior inventory years, the CO₂ emission factor of 3.57 metric tons CO₂ per metric ton NH₃ for the petroleum coke
 9 feedstock process (Bark 2004) was applied to the percent of total annual domestic ammonia production from
 10 petroleum coke feedstock. Beginning with this Inventory, the CO₂ emission factor for petroleum coke feedstock
 11 was updated to 3.52 metric tons of CO₂ per metric ton of NH₃. The updated emission factor is based on an average
 12 of the ratio of ammonia production from petroleum coke for years 2010 through 2015 (ACC 2020) and the facility-
 13 specific CO₂ emissions from the one ammonia production plant located in Kansas that is manufacturing ammonia
 14 from petroleum coke feedstock for years 2010 through 2015 (GHGRP 2020). Ammonia and urea are assumed to be
 15 manufactured in the same manufacturing complex, as both the raw materials needed for urea production are
 16 produced by the ammonia production process.

17 As a result of further examining the large increase in the amount of ammonia produced from petroleum coke
 18 between 2015 and 2016, another methodology change has been made for this Inventory. The amount of ammonia
 19 produced from petroleum coke changed significantly in 2016 because the parent company, CVR Energy, acquired a
 20 second plant that uses natural gas as a feedstock. Therefore, the amount of ammonia production reported by CVR
 21 Energy is no longer specific to the use of petroleum coke as a feedstock.

22 To correct this, beginning in 2016, the amount of CO₂ from the ammonia production plant located in Kansas that is
 23 manufacturing ammonia from petroleum coke feedstock (as reported under GHGRP 2020) is now being used,
 24 along with the emission factor of 3.52 metric tons of CO₂ per metric ton of NH₃ to back-calculate the amount of
 25 ammonia produced through the use of petroleum coke as feedstock.

26 The consumption of natural gas and petroleum coke as fossil fuel feedstocks for NH₃ production are adjusted for
 27 within the Energy chapter as these fuels were consumed during non-energy related activities. More information on
 28 this methodology is described in Annex 2.1, Methodology for Estimating Emissions of CO₂ from Fossil Fuel
 29 Combustion. See the Planned Improvements section on improvements of reporting fuel and feedstock CO₂
 30 emissions utilizing EPA’s GHGRP data to improve consistency with 2006 IPCC Guidelines.

31 The total ammonia production data for 2011 through 2019 were obtained from American Chemistry Council (ACC
 32 2020). For years before 2011, ammonia production data (see Table 4-21) were obtained from Coffeyville Resources
 33 (Coffeyville 2005, 2006, 2007a, 2007b, 2009, 2010, 2011, and 2012) and the Census Bureau of the U.S. Department
 34 of Commerce (U.S. Census Bureau 1991 through 1994, 1998 through 2011) as reported in *Current Industrial*
 35 *Reports Fertilizer Materials and Related Products* annual and quarterly reports. Urea-ammonia nitrate production
 36 from petroleum coke for years through 2011 was obtained from Coffeyville Resources (Coffeyville 2005, 2006,
 37 2007a, 2007b, 2009, 2010, 2011, and 2012), and from *CVR Energy, Inc. Annual Report* (CVR 2012 through 2015) for
 38 2012 through 2015. Urea production data for 1990 through 2008 were obtained from the *Minerals Yearbook:*
 39 *Nitrogen* (USGS 1994 through 2009). Urea production data for 2009 through 2010 were obtained from the U.S.
 40 Census Bureau (U.S. Census Bureau 2010 and 2011). The U.S. Census Bureau ceased collection of urea production
 41 statistics in 2011. Urea production values for the years 2011 through 2019 utilize GHGRP data (EPA 2018; EPA
 42 2020).

43 **Table 4-21: Ammonia Production, Recovered CO₂ Consumed for Urea Production, and Urea**
 44 **Production (kt)**

Year	Ammonia Production	Total CO ₂ Consumption for Urea Production	Urea Production
1990	15,425	5,463	7,450
2005	10,143	3,865	5,270

2015	11,765	4,312	5,880
2016	12,305	5,419	7,390
2017	14,070	6,622	9,030
2018	16,010	7,847	10,700
2019	16,410	8,360	11,400

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

The uncertainties presented in this section are primarily due to how accurately the emission factor used represents an average across all ammonia plants using natural gas feedstock. Uncertainties are also associated with ammonia production estimates and the assumption that all ammonia production and subsequent urea production was from the same process—conventional catalytic reforming of natural gas feedstock, with the exception of one ammonia production plant located in Kansas that is manufacturing ammonia from petroleum coke feedstock. Uncertainty is also associated with the representativeness of the emission factor used for the petroleum coke-based ammonia process. It is also assumed that ammonia and urea are produced at collocated plants from the same natural gas raw material. The uncertainty of the total urea production activity data, based on USGS *Minerals Yearbook: Nitrogen* data, is a function of the reliability of reported production data and is influenced by the completeness of the survey responses.

Recovery of CO₂ from ammonia production plants for purposes other than urea production (e.g., commercial sale, etc.) has not been considered in estimating the CO₂ emissions from ammonia production, as data concerning the disposition of recovered CO₂ are not available. Such recovery may or may not affect the overall estimate of CO₂ emissions depending upon the end use to which the recovered CO₂ is applied. Further research is required to determine whether byproduct CO₂ is being recovered from other ammonia production plants for application to end uses that are not accounted for elsewhere. However, for reporting purposes, CO₂ consumption for urea production is provided in this chapter.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-22. Carbon dioxide emissions from ammonia production in 2019 were estimated to be between 12.9 and 14.1 MMT CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 4 percent below and 5 percent above the emission estimate of 13.5 MMT CO₂ Eq.

Table 4-22: Approach 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Ammonia Production (MMT CO₂ Eq. and Percent)

Source	Gas	2019 Emission Estimate (MMT CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a (MMT CO ₂ Eq.)			
			Lower Bound	Upper Bound	Lower Bound (%)	Upper Bound (%)
Ammonia Production	CO ₂	13.5	12.9	14.1	-4%	+5%

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

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

QA/QC and Verification

General quality assurance/quality control (QA/QC) procedures were applied to ammonia production emission estimates consistent with the U.S. Inventory QA/QC plan, which is in accordance with Volume 1, Chapter 6 of 2006

1 *IPCC Guidelines* as described in the introduction of the IPPU chapter (see Annex 8 for more details). More details
2 on the greenhouse gas calculation, monitoring and QA/QC methods applicable to ammonia facilities can be found
3 under Subpart G (Ammonia Production) of the regulation (40 CFR Part 98).²⁶ EPA verifies annual facility-level
4 GHGRP reports through a multi-step process (e.g., combination of electronic checks and manual reviews) to
5 identify potential errors and ensure that data submitted to EPA are accurate, complete, and consistent.²⁷ Based on
6 the results of the verification process, EPA follows up with facilities to resolve mistakes that may have occurred.
7 The post-submittals checks are consistent with a number of general and category-specific QC procedures, including
8 range checks, statistical checks, algorithm checks, and year-to-year checks of reported data and emissions.

9 More details on the greenhouse gas calculation, monitoring and QA/QC methods applicable to reporting of urea
10 produced at ammonia production facilities can be found under Section 4.6 Urea Consumption for Non-Agricultural
11 Purposes.

12 Recalculations Discussion

13 Recalculations of ammonia emissions were performed for the 1990 through 2018 portion of the time series as
14 described below.

15 For years 2000 through 2018, the CO₂ emission factor for petroleum coke feedstock was updated from 3.57 metric
16 tons of CO₂ per metric ton of NH₃ (Bark 2004) to 3.52 metric tons of CO₂ per metric ton of NH₃.

17 For years 2016 through 2018, the methodologies for determining the amount of ammonia produced using
18 petroleum coke and for determining the amount of UAN produced using petroleum coke were changed, as
19 detailed in the Methodology section.

20 For the year 2018, the amount of ammonia production increased by 11 percent due to a correction to the value
21 used in the Inventory report for the years 1990 through 2018 based on the adjustments made in determining the
22 amount of ammonia produced using petroleum coke as mentioned above.

23 These changes resulted in recalculations of the estimated CO₂ emissions estimates shown in Table 4-19 and Table
24 4-20 for the 1990 through 2018 portion of the time series. For years 2000 through 2015, the values reported
25 decreased by less than 0.24 percent per year from the values reported in the previous Inventory report. For year
26 2016, the value decreased by 5 percent (593 kt CO₂); for year 2017, the value decreased by 16 percent (2,104 kt
27 CO₂), and for year 2018, the value decreased by 10 percent (1,369 kt CO₂).

28 Planned Improvements

29 Future improvements involve continuing to evaluate and analyze data reported under EPA's GHGRP to improve the
30 emission estimates for the Ammonia Production source category, in particular new data from updated reporting
31 requirements finalized in October of 2014 (79 FR 63750) and December 2016 (81 FR 89188),²⁸ that include facility-
32 level ammonia production data and feedstock consumption. The data were first reported by facilities in 2018 and
33 available post-verification to assess in 2019 for use in future Inventories, if the data meets GHGRP CBI aggregation
34 criteria. This data is still being evaluated and will be incorporated in future Inventory reports, if possible. Particular
35 attention will be made to ensure time-series consistency of the emission estimates presented in future Inventory
36 reports, along with application of appropriate category-specific QC procedures consistent with IPCC and UNFCCC
37 guidelines. For example, data reported in 2018 will reflect activity in 2017 and may not be representative of
38 activity in prior years of the time series. This assessment is required as the new facility-level reporting data from
39 EPA's GHGRP associated with new requirements are only applicable starting with reporting of emissions in

²⁶ See <http://www.ecfr.gov/cgi-bin/text-idx?tpl=/ecfrbrowse/Title40/40cfr98_main_02.tpl>.

²⁷ See <https://www.epa.gov/sites/production/files/2015-07/documents/ghgrp_verification_factsheet.pdf>.

²⁸ See <<https://www.epa.gov/ghgreporting/historical-rulemakings>>.

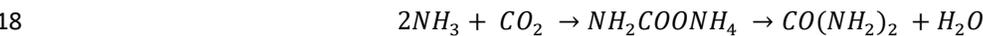
1 calendar year 2017, and thus are not available for all inventory years (i.e., 1990 through 2016) as required for this
2 Inventory.

3 In implementing improvements and integration of data from EPA’s GHGRP, the latest guidance from the IPCC on
4 the use of facility-level data in national inventories will be relied upon.²⁹ Specifically, the planned improvements
5 include assessing the anticipated new data to update the emission factors to include both fuel and feedstock CO₂
6 emissions to improve consistency with *2006 IPCC Guidelines*, in addition to reflecting CO₂ capture and storage
7 practices (beyond use of CO₂ for urea production). Methodologies will also be updated if additional ammonia
8 production plants are found to use hydrocarbons other than natural gas for ammonia production. Due to limited
9 resources and ongoing data collection efforts, this planned improvement is still in development and is not
10 incorporated into this Inventory. This is a long-term planned improvement.

11 4.6 Urea Consumption for Non-Agricultural 12 Purposes

13 Urea is produced using ammonia (NH₃) and carbon dioxide (CO₂) as raw materials. All urea produced in the United
14 States is assumed to be produced at ammonia production facilities where both ammonia and CO₂ are generated.
15 There were 35 plants producing ammonia in the United States in 2019, with two additional plants sitting idle for
16 the entire year (USGS 2020).

17 The chemical reaction that produces urea is:



19 This section accounts for CO₂ emissions associated with urea consumed exclusively for non-agricultural purposes.
20 Carbon dioxide emissions associated with urea consumed for fertilizer are accounted for in Section 5.6 Urea
21 Fertilization (CRF Source Category 3H) in the Agriculture chapter.

22 Urea is used as a nitrogenous fertilizer for agricultural applications and also in a variety of industrial applications.
23 The industrial applications of urea include its use in adhesives, binders, sealants, resins, fillers, analytical reagents,
24 catalysts, intermediates, solvents, dyestuffs, fragrances, deodorizers, flavoring agents, humectants and
25 dehydrating agents, formulation components, monomers, paint and coating additives, photosensitive agents, and
26 surface treatments agents. In addition, urea is used for abating nitrogen oxide (NO_x) emissions from coal-fired
27 power plants and diesel transportation motors.

28 Emissions of CO₂ from urea consumed for non-agricultural purposes in 2019 were estimated to be 6.6 MMT CO₂
29 Eq. (6,569 kt), and are summarized in Table 4-23 and Table 4-24. Net CO₂ emissions from urea consumption for
30 non-agricultural purposes have increased by approximately 74 percent from 1990 to 2019. The increase in
31 emissions since 2017 can be attributed to decreases in the amount of urea imported by the United States and
32 significant increases in urea exports.

33 **Table 4-23: CO₂ Emissions from Urea Consumption for Non-Agricultural Purposes (MMT CO₂**
34 **Eq.)**

Source	1990	2005	2015	2016	2017	2018	2019
Urea Consumption	3.8	3.7	4.6	5.1	5.0	6.1	6.6
Total	3.8	3.7	4.6	5.1	5.0	6.1	6.6

²⁹ See <http://www.ipcc-nggip.iges.or.jp/public/tb/TFI_Technical_Bulletin_1.pdf>.

1 **Table 4-24: CO₂ Emissions from Urea Consumption for Non-Agricultural Purposes (kt)**

Source	1990	2005	2015	2016	2017	2018	2019
Urea Consumption	3,784	3,653	4,578	5,132	4,972	6,056	6,569
Total	3,784	3,653	4,578	5,132	4,972	6,056	6,569

2 Methodology

3 Emissions of CO₂ resulting from urea consumption for non-agricultural purposes are estimated by multiplying the
 4 amount of urea consumed in the United States for non-agricultural purposes by a factor representing the amount
 5 of CO₂ used as a raw material to produce the urea. This method is based on the assumption that all of the carbon
 6 in urea is released into the environment as CO₂ during use, consistent with the Tier 1 method used to estimate
 7 emissions from ammonia production in the *2006 IPCC Guidelines* (IPCC 2006) which states that the “CO₂ recovered
 8 [from ammonia production] for downstream use can be estimated from the quantity of urea produced where CO₂
 9 is estimated by multiplying urea production by 44/60, the stoichiometric ratio of CO₂ to urea.”

10 The amount of urea consumed for non-agricultural purposes in the United States is estimated by deducting the
 11 quantity of urea fertilizer applied to agricultural lands, which is obtained directly from the Agriculture chapter (see
 12 Table 5-25), from the total domestic supply of urea as reported in Table 4-25. In previous Inventory reports, the
 13 quantity of urea fertilizer applied to agricultural lands was obtained directly from the Section 6.4 *Cropland*
 14 *Remaining Cropland* section of the Land Use, Land Use Change, and Forestry chapter. The domestic supply of urea
 15 is estimated based on the amount of urea produced plus urea imports and minus urea exports. A factor of 0.733
 16 tons of CO₂ per ton of urea consumed is then applied to the resulting supply of urea for non-agricultural purposes
 17 to estimate CO₂ emissions from the amount of urea consumed for non-agricultural purposes. The 0.733 tons of CO₂
 18 per ton of urea emission factor is based on the stoichiometry of C in urea. This corresponds to a stoichiometric CO₂
 19 to urea factor of 44/60, assuming complete conversion of C in urea to CO₂ (IPCC 2006; EFMA 2000).

20 Urea production data for 1990 through 2008 were obtained from the U.S. Geological Survey (USGS) *Minerals*
 21 *Yearbook: Nitrogen* (USGS 1994 through 2009a). Urea production data for 2009 through 2010 were obtained from
 22 the U.S. Census Bureau (2011). The U.S. Census Bureau ceased collection of urea production statistics in 2011.
 23 Starting with the Inventory report for the years 1990 through 2017, EPA began utilizing urea production data from
 24 EPA’s GHGRP to estimate emissions. Urea production values in the current Inventory report utilize GHGRP data for
 25 the years 2011 through 2019 (EPA 2018, EPA 2020).

26 Urea import data for 2018 and 2019 are not yet publicly available, so 2017 data have been used as a proxy. Urea
 27 import data for 2013 to 2017 were obtained from the USGS *Minerals Yearbook: Nitrogen* (USGS 2019a). Urea
 28 import data for 2011 and 2012 were taken from *U.S. Fertilizer Import/Exports* from the United States Department
 29 of Agriculture (USDA) Economic Research Service Data Sets (U.S. Department of Agriculture 2012). USDA
 30 suspended updates to this data after 2012. Urea import data for the previous years were obtained from the U.S.
 31 Census Bureau *Current Industrial Reports Fertilizer Materials and Related Products* annual and quarterly reports for
 32 1997 through 2010 (U.S. Census Bureau 2001 through 2011), The Fertilizer Institute (TFI 2002) for 1993 through
 33 1996, and the United States International Trade Commission Interactive Tariff and Trade DataWeb (U.S. ITC 2002)
 34 for 1990 through 1992 (see Table 4-25).

35 Urea export data for 2018 and 2019 are not yet publicly available and so 2017 data have been used as a proxy.
 36 Urea export data for 2013 to 2017 were obtained from the USGS *Minerals Yearbook: Nitrogen* (USGS 2019a). Urea
 37 export data for 1990 through 2012 were taken from *U.S. Fertilizer Import/Exports* from USDA Economic Research
 38 Service Data Sets (U.S. Department of Agriculture 2012). USDA suspended updates to this data after 2012.

1 **Table 4-25: Urea Production, Urea Applied as Fertilizer, Urea Imports, and Urea Exports (kt)**

Year	Urea Production	Urea Applied as Fertilizer	Urea Imports	Urea Exports	Urea Consumed for Non-Agricultural Purposes
1990	7,450	3,296	1,860	854	5,160
2005	5,270	4,779	5,026	536	4,981
2015	5,880	6,447	7,190	380	6,243
2016	7,390	6,651	6,580	321	6,998
2017	9,030	6,888	5,510	872	6,780
2018	10,700	7,080	5,510	872	8,258
2019	11,400	7,080	5,510	872	8,958

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

4 There is limited publicly available data on the quantities of urea produced and consumed for non-agricultural
 5 purposes. Therefore, the amount of urea used for non-agricultural purposes is estimated based on a balance that
 6 relies on estimates of urea production, urea imports, urea exports, and the amount of urea used as fertilizer. The
 7 primary uncertainties associated with this source category are associated with the accuracy of these estimates as
 8 well as the fact that each estimate is obtained from a different data source. Because urea production estimates are
 9 no longer available from the USGS, there is additional uncertainty associated with urea produced beginning in
 10 2011. There is also uncertainty associated with the assumption that all of the carbon in urea is released into the
 11 environment as CO₂ during use.

12 The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-26. Carbon dioxide
 13 emissions associated with urea consumption for non-agricultural purposes during 2018 were estimated to be
 14 between 3.0 and 4.2 MMT CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 16
 15 percent below and 16 percent above the emission estimate of 3.6 MMT CO₂ Eq.

16 **Table 4-26: Approach 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Urea**
 17 **Consumption for Non-Agricultural Purposes (MMT CO₂ Eq. and Percent)**

Source	Gas	2019 Emission Estimate (MMT CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a (MMT CO ₂ Eq.)			
			Lower Bound	Upper Bound	Lower Bound (%)	Upper Bound (%)
Urea Consumption for Non-Agricultural Purposes	CO ₂	3.6	3.0	4.2	-16%	+16%

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

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

21 **QA/QC and Verification**

22 General quality assurance/quality control (QA/QC) procedures were applied consistent with the U.S. Inventory
 23 QA/QC plan, which is in accordance with Volume 1, Chapter 6 of *2006 IPCC Guidelines* as described in the
 24 introduction of the IPPU chapter (see Annex 8 for more details).

1 More details on the greenhouse gas calculation, monitoring and QA/QC methods applicable to reporting of urea
2 production occurring at ammonia facilities can be found under Subpart G (Ammonia Manufacturing) of the
3 regulation (40 CFR Part 98).³⁰ EPA verifies annual facility-level GHGRP reports through a multi-step process (e.g.,
4 combination of electronic checks and manual reviews) to identify potential errors and ensure that data submitted
5 to EPA are accurate, complete, and consistent.³¹ Based on the results of the verification process, EPA follows up
6 with facilities to resolve mistakes that may have occurred. The post-submittals checks are consistent with a
7 number of general and category-specific QC procedures, including range checks, statistical checks, algorithm
8 checks, and year-to-year checks of reported data and emissions. EPA also conducts QA checks of GHGRP reported
9 urea production data against external datasets including the USGS *Minerals Yearbook* data. The comparison shows
10 consistent trends in urea production over time.

11 Recalculations Discussion

12 Based on updated urea production data from EPA's GHGRP for 2017 and 2018, recalculations were performed for
13 these two years. Compared to the previous Inventory, CO₂ emissions from urea consumption for non-agricultural
14 purposes increased by 32 percent (1,203 kt CO₂) for 2017 and 67 percent (2,428 kt CO₂) for 2018, due to large
15 increases in urea production for both years.

16 4.7 Nitric Acid Production (CRF Source 17 Category 2B2)

18 Nitrous oxide (N₂O) is emitted during the production of nitric acid (HNO₃), an inorganic compound used primarily
19 to make synthetic commercial fertilizers. Nitric acid is also a major component in the production of adipic acid—a
20 feedstock for nylon—and explosives. Virtually all of the nitric acid produced in the United States is manufactured
21 by the high-temperature catalytic oxidation of ammonia (EPA 1998). There are two different nitric acid production
22 methods: weak nitric acid and high-strength nitric acid. The first method utilizes oxidation, condensation, and
23 absorption to produce nitric acid at concentrations between 30 and 70 percent nitric acid. High-strength acid (90
24 percent or greater nitric acid) can be produced from dehydrating, bleaching, condensing, and absorption of the
25 weak nitric acid. Most U.S. plants were built between 1960 and 2000. As of 2019, there were 31 active nitric acid
26 production plants, including one high-strength nitric acid production plant in the United States (EPA 2010; EPA
27 2020).

28 The basic process technology for producing nitric acid has not changed significantly over time. During this process,
29 N₂O is formed as a byproduct and is released from reactor vents into the atmosphere. Emissions from fuels
30 consumed for energy purposes during the production of nitric acid are included in the Energy chapter.

31 Nitric acid is made from the reaction of ammonia (NH₃) with oxygen (O₂) in two stages. The overall reaction is:



33 Currently, the nitric acid industry controls emissions of NO and NO₂ (i.e., NO_x). As such, the industry in the United
34 States uses a combination of non-selective catalytic reduction (NSCR) and selective catalytic reduction (SCR)
35 technologies. In the process of destroying NO_x, NSCR systems are also very effective at destroying N₂O. NSCR units,
36 however, are generally not preferred in modern plants because of high energy costs and associated high gas
37 temperatures. NSCR systems were installed in nitric plants built between 1971 and 1977 and are used in

³⁰ See <http://www.ecfr.gov/cgi-bin/text-idx?tpl=/ecfrbrowse/Title40/40cfr98_main_02.tpl>.

³¹ See <https://www.epa.gov/sites/production/files/2015-07/documents/ghgrp_verification_factsheet.pdf>.

1 approximately one-third of the weak acid production plants. U.S. facilities are using both tertiary (i.e., NSCR) and
 2 secondary controls (i.e., alternate catalysts).

3 Nitrous oxide emissions from this source were estimated to be 10.0 MMT CO₂ Eq. (34 kt of N₂O) in 2019 (see Table
 4 4-27). Emissions from nitric acid production have decreased by 18 percent since 1990, while production has
 5 increased by 12 percent over the same time period. Emissions have decreased by 31 percent since 1997, the
 6 highest year of production in the time series.

7 **Table 4-27: N₂O Emissions from Nitric Acid Production (MMT CO₂ Eq. and kt N₂O)**

Year	MMT CO ₂ Eq.	kt N ₂ O
1990	12.1	41
2005	11.3	38
2015	11.6	39
2016	10.1	34
2017	9.3	31
2018	9.6	32
2019	10.0	34

8 **Methodology**

9 Emissions of N₂O were calculated using the estimation methods provided by the *2006 IPCC Guidelines* and a
 10 country-specific method utilizing EPA’s GHGRP. The *2006 IPCC Guidelines* Tier 2 method was used to estimate
 11 emissions from nitric acid production for 1990 through 2009, and a country-specific approach similar to the IPCC
 12 Tier 3 method was used to estimate N₂O emissions for 2010 through 2019.

13 **2010 through 2019**

14 Process N₂O emissions and nitric acid production data were obtained directly from EPA’s GHGRP for 2010 through
 15 2019 by aggregating reported facility-level data (EPA 2020).

16 Since 2010, in the United States, all nitric acid facilities that produce weak nitric acid (30 to 70 percent) have been
 17 required to report annual greenhouse gas emissions data to EPA as per the requirements of the GHGRP (Subpart
 18 V). Beginning with 2018, the rule was changed to include facilities that produce nitric acid of any strength. The only
 19 facility that produces high-strength nitric acid also produces weak nitric acid. All greenhouse gas emissions from
 20 nitric acid production originate from the production of weak nitric acid.

21 Process emissions and nitric acid production reported to the GHGRP provide complete estimates of greenhouse
 22 gas emissions for the United States because there are no reporting thresholds. While facilities are allowed to stop
 23 reporting to the GHGRP if the total reported emissions from nitric acid production are less than 25,000 metric tons
 24 CO₂ Eq. per year for five consecutive years or less than 15,000 metric tons CO₂ Eq. per year for three consecutive
 25 years, no facilities have stopped reporting as a result of these provisions.³² All nitric acid facilities are required to
 26 calculate process emissions using a site-specific emission factor developed through annual performance testing
 27 under typical operating conditions or by directly measuring N₂O emissions using monitoring equipment.³³

³² See 40 CFR 98.2(i)(1) and 40 CFR 98.2(i)(2) for more information about these provisions.

³³ Facilities must use standard methods, either EPA Method 320 or ASTM D6348-03 for annual performance tests and must follow associated QA/QC procedures consistent during these performance test consistent with category-specific QC of direct emission measurements.

1 Emissions from facilities vary from year to year, depending on the amount of nitric acid produced with and without
2 abatement technologies. To maintain consistency across the time series and with the rounding approaches taken
3 by other data sets, GHGRP nitric acid data are rounded for consistency and are shown in Table 4-20.

4 **1990 through 2009**

5 Using GHGRP data for 2010,³⁴ country-specific N₂O emission factors were calculated for nitric acid production with
6 abatement and without abatement (i.e., controlled and uncontrolled emission factors). The following 2010
7 emission factors were derived for production with abatement and without abatement: 3.3 kg N₂O/metric ton
8 HNO₃ produced at plants using abatement technologies (e.g., tertiary systems such as NSCR systems) and 5.99 kg
9 N₂O/metric ton HNO₃ produced at plants not equipped with abatement technology. Country-specific weighted
10 emission factors were derived by weighting these emission factors by percent production with abatement and
11 without abatement over time periods 1990 through 2008 and 2009. These weighted emission factors were used to
12 estimate N₂O emissions from nitric acid production for years prior to the availability of GHGRP data (i.e., 1990
13 through 2008 and 2009). A separate weighted emission factor is included for 2009 due to data availability for that
14 year. At that time, EPA had initiated compilation of a nitric acid database to improve estimation of emissions from
15 this industry and obtained updated information on application of controls via review of permits and outreach with
16 facilities and trade associations. The research indicated recent installation of abatement technologies at additional
17 facilities.

18 Based on the available data, it was assumed that emission factors for 2010 would be more representative of
19 operating conditions in 1990 through 2009 than more recent years. Initial review of historical data indicates that
20 percent production with and without abatement can change over time and from year to year due to changes in
21 application of facility-level abatement technologies, maintenance of abatement technologies, and also due to plant
22 closures and start-ups (EPA 2012, 2013; Desai 2012; CAR 2013). The installation dates of N₂O abatement
23 technologies are not known at most facilities, but it is assumed that facilities reporting abatement technology use
24 have had this technology installed and operational for the duration of the time series considered in this report
25 (especially NSCRs).

26 The country-specific weighted N₂O emission factors were used in conjunction with annual production to estimate
27 N₂O emissions for 1990 through 2009, using the following equations:

$$E_i = P_i \times EF_{weighted,i}$$

$$EF_{weighted,i} = [(\%P_{c,i} \times EF_c) + (\%P_{unc,i} \times EF_{unc})]$$

30 where,

31	E_i	= Annual N ₂ O Emissions for year i (kg/yr)
32	P_i	= Annual nitric acid production for year i (metric tons HNO ₃)
33	$EF_{weighted,i}$	= Weighted N ₂ O emission factor for year i (kg N ₂ O/metric ton HNO ₃)
34	$\%P_{c,i}$	= Percent national production of HNO ₃ with N ₂ O abatement technology (%)
35	EF_c	= N ₂ O emission factor, with abatement technology (kg N ₂ O/metric ton HNO ₃)
36	$\%P_{unc,i}$	= Percent national production of HNO ₃ without N ₂ O abatement technology (%)
37	EF_{unc}	= N ₂ O emission factor, without abatement technology (kg N ₂ O/metric ton HNO ₃)
38	i	= year from 1990 through 2009

- 40
- For 2009: Weighted N₂O emission factor = 5.46 kg N₂O/metric ton HNO₃.
 - For 1990 through 2008: Weighted N₂O emission factor = 5.66 kg N₂O/metric ton HNO₃.
- 41

³⁴ National N₂O process emissions, national production, and national share of nitric acid production with abatement and without abatement technology was aggregated from the GHGRP facility-level data for 2010 to 2017 (i.e., percent production with and without abatement).

1 Nitric acid production data for the United States for 1990 through 2009 were obtained from the U.S. Census
2 Bureau (U.S. Census Bureau 2008, 2009, 2010a, 2010b) (see Table 4-28). Publicly available information on plant-
3 level abatement technologies was used to estimate the shares of nitric acid production with and without
4 abatement for 2008 and 2009 (EPA 2012, 2013; Desai 2012; CAR 2013). EPA has previously conducted a review of
5 operating permits to obtain more current information due to the lack of publicly-available data on use of
6 abatement technologies for 1990 through 2007, as stated previously; therefore, the share of national production
7 with and without abatement for 2008 was assumed to be constant for 1990 through 2007.

8 **Table 4-28: Nitric Acid Production (kt)**

Year	kt
1990	7,200
2005	6,710
2015	7,210
2016	7,810
2017	7,780
2018	8,210
2019	8,080

9 **Uncertainty and Time-Series Consistency – TO BE UPDATED** 10 **FOR FINAL REPORT**

11 Uncertainty associated with the parameters used to estimate N₂O emissions includes the share of U.S. nitric acid
12 production attributable to each emission abatement technology over the time series (especially prior to 2010), and
13 the associated emission factors applied to each abatement technology type. While some information has been
14 obtained through outreach with industry associations, limited information is available over the time series
15 (especially prior to 2010) for a variety of facility level variables, including plant-specific production levels, plant
16 production technology (e.g., low, high pressure, etc.), and abatement technology type, installation date of
17 abatement technology, and accurate destruction and removal efficiency rates. Production data prior to 2010 were
18 obtained from National Census Bureau, which does not provide uncertainty estimates with their data. Facilities
19 reporting to EPA’s GHGRP must measure production using equipment and practices used for accounting purposes.
20 At this time EPA does not estimate uncertainty of the aggregated facility-level information. As noted in the QA/QC
21 and verification section below, EPA verifies annual facility-level reports through a multi-step process (e.g.,
22 combination of electronic checks and manual reviews by staff) to identify potential errors and ensure that data
23 submitted to EPA are accurate, complete, and consistent. The annual production reported by each nitric acid
24 facility under EPA’s GHGRP and then aggregated to estimate national N₂O emissions is assumed to have low
25 uncertainty.

26 The results of this Approach 2 quantitative uncertainty analysis are summarized in Table 4-29. Nitrous oxide
27 emissions from nitric acid production were estimated to be between 8.9 and 9.8 MMT CO₂ Eq. at the 95 percent
28 confidence level. This indicates a range of approximately 5 percent below to 5 percent above the 2017 emissions
29 estimate of 9.3 MMT CO₂ Eq.

Table 4-29: Approach 2 Quantitative Uncertainty Estimates for N₂O Emissions from Nitric Acid Production (MMT CO₂ Eq. and Percent)

Source	Gas	2019 Emission Estimate (MMT CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			(MMT CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Nitric Acid Production	N ₂ O	9.3	8.9	9.8	-5%	+5%

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

Methodological approaches were applied to the entire time series to ensure consistency in emissions from 1990 through 2019.

QA/QC and Verification

General quality assurance/quality control (QA/QC) procedures were applied consistent with the U.S. Inventory QA/QC plan, which is in accordance with Volume 1, Chapter 6 of the *2006 IPCC Guidelines* as described in the introduction of the IPPU chapter (see Annex 8 for more details). More details on the greenhouse gas calculation, monitoring and QA/QC methods applicable to nitric acid facilities can be found under Subpart V: Nitric Acid Production of the GHGRP regulation (40 CFR Part 98).³⁵

The main QA/QC activities are related to annual performance testing, which must follow either EPA Method 320 or ASTM D6348-03. EPA verifies annual facility-level GHGRP reports through a multi-step process that is tailored to the Subpart (e.g., combination of electronic checks including range checks, statistical checks, algorithm checks, year-to-year comparison checks, along with manual reviews) to identify potential errors and ensure that data submitted to EPA are accurate, complete, and consistent. Based on the results of the verification process, EPA follows up with facilities to resolve mistakes that may have occurred (EPA 2015).³⁶

Recalculations Discussion

Recalculations of emissions from nitric acid production were performed for the 1990 through 2018 time series when the GHGRP data for 2018 were released in November 2020. Previously, the 2017 value was used as proxy for 2018. The change resulted in recalculations of the estimated CO₂ emissions estimates shown in Table 4-19 and Table 4-20. Compared to the previous Inventory, the emissions value for 2018 increased by 3 percent (0.3 MMT CO₂ Eq.), and the nitric acid production value for 2018 increased by 6 percent (430 kt).

Planned Improvements

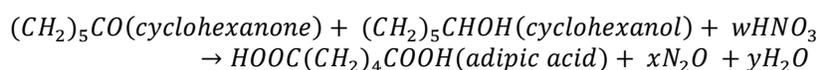
Pending resources, EPA is considering both near-term and long-term improvement to estimates and associated characterization of uncertainty. In the short-term, with 8 years of EPA's GHGRP data, EPA anticipates completing updates of category-specific QC procedures to potentially also improve both qualitative and quantitative uncertainty estimates. In the next Inventory, EPA anticipates including information from GHGRP facilities on the installation date of any N₂O abatement equipment, per revisions finalized in December 2016 to EPA's GHGRP. This information will enable more accurate estimation of N₂O emissions from nitric acid production over the time series.

³⁵ See Subpart V monitoring and reporting regulation <http://www.ecfr.gov/cgi-bin/text-idx?tpl=/ecfrbrowse/Title40/40cfr98_main_02.tpl>.

³⁶ See GHGRP Verification Factsheet <https://www.epa.gov/sites/production/files/2015-07/documents/ghgrp_verification_factsheet.pdf>.

4.8 Adipic Acid Production (CRF Source Category 2B3)

Adipic acid is produced through a two-stage process during which nitrous oxide (N₂O) is generated in the second stage. Emissions from fuels consumed for energy purposes during the production of adipic acid are accounted for in the Energy chapter. The first stage of manufacturing usually involves the oxidation of cyclohexane to form a cyclohexanone/cyclohexanol mixture. The second stage involves oxidizing this mixture with nitric acid to produce adipic acid. Nitrous oxide is generated as a byproduct of the nitric acid oxidation stage and is emitted in the waste gas stream (Thiemens and Trogler 1991). The second stage is represented by the following chemical reaction:



Process emissions from the production of adipic acid vary with the types of technologies and level of emission controls employed by a facility. In 1990, two major adipic acid-producing plants had N₂O abatement technologies in place and, as of 1998, three major adipic acid production facilities had control systems in place (Reimer et al. 1999). In 2018, catalytic reduction, non-selective catalytic reduction (NSCR), and thermal reduction abatement technologies were applied as N₂O abatement measures at adipic acid facilities (EPA 2019, 2020).

Worldwide, only a few adipic acid plants exist. The United States, Europe, and China are the major producers, with the United States accounting for the largest share of global adipic acid production capacity in recent years. In 2019, the United States had two companies with a total of two adipic acid production facilities (one in Texas and one in Florida), following the ceased operations of a third major production facility at the end of 2015 (EPA 2019, 2020).

Adipic acid is a white crystalline solid used in the manufacture of synthetic fibers, plastics, coatings, urethane foams, elastomers, and synthetic lubricants. Commercially, it is the most important of the aliphatic dicarboxylic acids, which are used to manufacture polyesters. Eighty-four percent of all adipic acid produced in the United States is used in the production of nylon 6,6; 9 percent is used in the production of polyester polyols; 4 percent is used in the production of plasticizers; and the remaining 4 percent is accounted for by other uses, including unsaturated polyester resins and food applications (ICIS 2007). Food grade adipic acid is used to provide some foods with a “tangy” flavor (Thiemens and Trogler 1991).

National adipic acid production has increased by approximately 7 percent over the period of 1990 through 2019, to approximately 810,000 metric tons (ACC 2020). Nitrous oxide emissions from adipic acid production were estimated to be 5.3 MMT CO₂ Eq. (18 kt N₂O) in 2019 (see Table 4-30). Over the period 1990 through 2019, emissions have been reduced by 65 percent due to both the widespread installation of pollution control measures in the late 1990s and plant idling in the late 2000s. The total emissions from adipic acid production decreased by approximately 49 percent from GHGRP Reporting Year (RY) 2018 to RY2019 due to a significant change in emissions from one facility. The facility confirmed that there was a decrease in adipic acid production and an increase in the use of the N₂O abatement device in RY2019, resulting in a large decrease in greenhouse gas emissions (EPA 2019, 2020). As noted above, changes in control measures and abatement technologies at adipic acid production facilities, including maintenance of equipment, can result in annual emission fluctuations. Little additional information is available on drivers of trends in adipic acid production as it is not reported under EPA’s GHGRP.

Table 4-30: N₂O Emissions from Adipic Acid Production (MMT CO₂ Eq. and kt N₂O)

Year	MMT CO ₂ Eq.	kt N ₂ O
1990	15.2	51
2005	7.1	24

2015	4.3	14
2016	7.0	24
2017	7.4	25
2018	10.3	35
2019	5.3	18

1 Methodology

2 Emissions are estimated using both Tier 2 and Tier 3 methods consistent with the *2006 IPCC Guidelines*. Due to
3 confidential business information (CBI), plant names are not provided in this section. Therefore, the four adipic
4 acid-producing facilities that have operated over the time series will be referred to as Plants 1 through 4. Overall,
5 as noted above, the two currently operating facilities use catalytic reduction, NSCR and thermal reduction
6 abatement technologies.

7 2010 through 2019

8 All emission estimates for 2010 through 2019 were obtained through analysis of GHGRP data (EPA 2010 through
9 2020), which is consistent with the *2006 IPCC Guidelines* Tier 3 method. Facility-level greenhouse gas emissions
10 data were obtained from EPA’s GHGRP for the years 2010 through 2019 (EPA 2010 through 2020) and aggregated
11 to national N₂O emissions. Consistent with IPCC Tier 3 methods, all adipic acid production facilities are required to
12 calculate emissions using a facility-specific emission factor developed through annual performance testing under
13 typical operating conditions or by directly measuring N₂O emissions using monitoring equipment.³⁷

14 1990 through 2009

15 For years 1990 through 2009, which were prior to EPA’s GHGRP reporting, for both Plants 1 and 2, emission
16 estimates were obtained directly from the plant engineers and account for reductions due to control systems in
17 place at these plants during the time series. These prior estimates are considered CBI and hence are not published
18 (Desai 2010, 2011). These estimates were based on continuous process monitoring equipment installed at the two
19 facilities.

20 For Plant 4, 1990 through 2009 N₂O emissions were estimated using the following Tier 2 equation from the *2006*
21 *IPCC Guidelines*:

$$22 \quad E_{aa} = Q_{aa} \times EF_{aa} \times (1 - [DF \times UF])$$

23 where,

24	E_{aa}	=	N ₂ O emissions from adipic acid production, metric tons
25	Q_{aa}	=	Quantity of adipic acid produced, metric tons
26	EF_{aa}	=	Emission factor, metric ton N ₂ O/metric ton adipic acid produced
27	DF	=	N ₂ O destruction factor
28	UF	=	Abatement system utility factor

29 The adipic acid production is multiplied by an emission factor (i.e., N₂O emitted per unit of adipic acid produced),
30 which has been estimated to be approximately 0.3 metric tons of N₂O per metric ton of product (IPCC 2006). The
31 “N₂O destruction factor” in the equation represents the percentage of N₂O emissions that are destroyed by the
32 installed abatement technology. The “abatement system utility factor” represents the percentage of time that the
33 abatement equipment operates during the annual production period. Plant-specific production data for Plant 4

³⁷ Facilities must use standard methods, either EPA Method 320 or ASTM D6348-03 for annual performance testing, and must follow associated QA/QC procedures during these performance tests consistent with category-specific QC of direct emission measurements.

1 were obtained across the time series through personal communications (Desai 2010, 2011). The plant-specific
 2 production data were then used for calculating emissions as described above.

3 For Plant 3, 2005 through 2009 emissions were obtained directly from the plant (Desai 2010, 2011). For 1990
 4 through 2004, emissions were estimated using plant-specific production data and the IPCC factors as described
 5 above for Plant 4. Plant-level adipic acid production for 1990 through 2003 was estimated by allocating national
 6 adipic acid production data to the plant level using the ratio of known plant capacity to total national capacity for
 7 all U.S. plants (ACC 2020; CMR 2001, 1998; CW 1999; C&EN 1992 through 1995). For 2004, actual plant production
 8 data were obtained and used for emission calculations (CW 2005).

9 Plant capacities for 1990 through 1994 were obtained from *Chemical & Engineering News*, “Facts and Figures” and
 10 “Production of Top 50 Chemicals” (C&EN 1992 through 1995). Plant capacities for 1995 and 1996 were kept the
 11 same as 1994 data. The 1997 plant capacities were taken from *Chemical Market Reporter*, “Chemical Profile: Adipic
 12 Acid” (CMR 1998). The 1998 plant capacities for all four plants and 1999 plant capacities for three of the plants
 13 were obtained from *Chemical Week*, Product Focus: Adipic Acid/Adiponitrile (CW 1999). Plant capacities for the
 14 year 2000 for three of the plants were updated using *Chemical Market Reporter*, “Chemical Profile: Adipic Acid”
 15 (CMR 2001). For 2001 through 2003, the plant capacities for three plants were held constant at year 2000
 16 capacities. Plant capacity for 1999 to 2003 for the one remaining plant was kept the same as 1998.

17 National adipic acid production data (see Table 4-31) from 1990 through 2019 were obtained from the American
 18 Chemistry Council (ACC 2020).

19 **Table 4-31: Adipic Acid Production (kt)**

Year	kt
1990	755
2005	865
2015	1,055
2016	860
2017	830
2018	825
2019	810

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

22 Uncertainty associated with N₂O emission estimates includes the methods used by companies to monitor and
 23 estimate emissions. While some information has been obtained through outreach with facilities, limited
 24 information is available over the time series on these methods, abatement technology destruction and removal
 25 efficiency rates and plant-specific production levels.

26 The results of this Approach 2 quantitative uncertainty analysis are summarized in

27 Table 4-32. Nitrous oxide emissions from adipic acid production for 2018 were estimated to be between 9.8 and
 28 10.8 MMT CO₂ Eq. at the 95 percent confidence level. These values indicate a range of approximately 5 percent
 29 below to 5 percent above the 2018 emission estimate of 10.3 MMT CO₂ Eq.

30 **Table 4-32: Approach 2 Quantitative Uncertainty Estimates for N₂O Emissions from Adipic**
 31 **Acid Production (MMT CO₂ Eq. and Percent)**

Source	Gas	2018 Emission Estimate	Uncertainty Range Relative to Emission Estimate ^a
--------	-----	------------------------	--

		(MMT CO ₂ Eq.)		(%)	
		Lower Bound	Upper Bound	Lower Bound	Upper Bound
Adipic Acid Production	N ₂ O	9.8	10.8	-5%	+5%

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

1 Methodological approaches were applied to the entire time series to ensure consistency in emissions from 1990
2 through 2018.

3 QA/QC and Verification

4 General quality assurance/quality control (QA/QC) procedures were applied consistent with the U.S. Inventory
5 QA/QC plan, which is in accordance with Volume 1, Chapter 6 of the *2006 IPCC Guidelines* as described in the
6 introduction of the IPPU chapter (see Annex 8 for more details).

7 More details on the greenhouse gas calculation, monitoring and QA/QC methods applicable to adipic acid facilities
8 can be found under Subpart E (Adipic Acid Production) of the GHGRP regulation (40 CFR Part 98).³⁸ The main
9 QA/QC activities are related to annual performance testing, which must follow either EPA Method 320 or ASTM
10 D6348-03. EPA verifies annual facility-level GHGRP reports through a multi-step process (e.g., combination of
11 electronic checks and manual reviews) to identify potential errors and ensure that data submitted to EPA are
12 accurate, complete, and consistent (EPA 2015).³⁹ Based on the results of the verification process, EPA follows up
13 with facilities to resolve mistakes that may have occurred. The post-submittals checks are consistent with a
14 number of general and category-specific QC procedures, including range checks, statistical checks, algorithm
15 checks, and year-to-year comparisons of reported data.

16 Recalculations Discussion

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

18 Planned Improvements

19 EPA plans to review GHGRP facility reported information on the date of abatement technology installation in order
20 to better reflect trends and changes in emissions abatement within the industry across the time series. See more
21 detail on similar planned improvements within Section 4.7 on Nitric Acid Production presented above.

22 4.9 Caprolactam, Glyoxal and Glyoxylic Acid 23 Production (CRF Source Category 2B4)

24 *Caprolactam*

25 Caprolactam (C₆H₁₁NO) is a colorless monomer produced for nylon-6 fibers and plastics. A substantial proportion
26 of the fiber is used in carpet manufacturing. Most commercial processes used for the manufacture of caprolactam

³⁸ See <http://www.ecfr.gov/cgi-bin/text-idx?tpl=/ecfrbrowse/Title40/40cfr98_main_02.tpl>.

³⁹ See <https://www.epa.gov/sites/production/files/2015-07/documents/ghgrp_verification_factsheet.pdf>.

1 begin with benzene, but toluene can also be used. The production of caprolactam can give rise to significant
2 emissions of nitrous oxide (N₂O).

3 During the production of caprolactam, emissions of N₂O can occur from the ammonia oxidation step, emissions of
4 carbon dioxide (CO₂) from the ammonium carbonate step, emissions of sulfur dioxide (SO₂) from the ammonium
5 bisulfite step, and emissions of non-methane volatile organic compounds (NMVOCs). Emissions of CO₂, SO₂ and
6 NMVOCs from the conventional process are unlikely to be significant in well-managed plants. Modified
7 caprolactam production processes are primarily concerned with elimination of the high volumes of ammonium
8 sulfate that are produced as a byproduct of the conventional process (IPCC 2006).

9 Where caprolactam is produced from benzene, the main process, the benzene is hydrogenated to cyclohexane
10 which is then oxidized to produce cyclohexanone (C₆H₁₀O). The classical route (Raschig process) and basic reaction
11 equations for production of caprolactam from cyclohexanone are (IPCC 2006):

12

13 *Oxidation of NH₃ to NO/NO₂*

14 ↓

15 *NH₃ reacted with CO₂/H₂O to yield ammonium carbonate (NH₄)₂CO₃*

16 ↓

17 *(NH₄)₂CO₃ reacted with NO/NO₂ (from NH₃ oxidation) to yield ammonium nitrite (NH₄NO₂)*

18 ↓

19 *NH₃ reacted with SO₂/H₂O to yield ammonium bisulphite (NH₄HSO₃)*

20 ↓

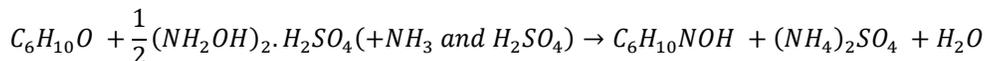
21 *NH₄NO₂ and (NH₄HSO₃) reacted to yield hydroxylamine disulphonate (NOH(SO₃NH₄)₂)*

22 ↓

23 *(NOH(SO₃NH₄)₂) hydrolised to yield hydroxylamine sulphate ((NH₂OH)₂.H₂SO₄) and
24 ammonium sulphate ((NH₄)₂SO₄)*

25 ↓

26 *Cyclohexanone reaction:*



28 ↓

29 *Beckmann rearrangement:*



31

32 In 1999, there were four caprolactam production facilities in the United States. As of 2019, the United States had
33 two companies that produce caprolactam with a total of two caprolactam production facilities: AdvanSix in Virginia
34 (AdvanSix 2020) and BASF in Texas (BASF 2020). Caprolactam production at Fibrant LLC in Georgia ceased in 2018
35 (Cline 2019).

36 Nitrous oxide emissions from caprolactam production in the United States were estimated to be 1.4 MMT CO₂ Eq.
37 (5 kt N₂O) in 2019 (see Table 4-33). National emissions from caprolactam production decreased by approximately
38 18 percent over the period of 1990 through 2019. Emissions in 2019 decreased by approximately 3 percent from
39 the 2018 levels.

1 **Table 4-33: N₂O Emissions from Caprolactam Production (MMT CO₂ Eq. and kt N₂O)**

Year	MMT CO ₂ Eq.	kt N ₂ O
1990	1.7	6
2005	2.1	7
2015	1.9	6
2016	1.7	6
2017	1.5	5
2018	1.4	5
2019	1.4	5

2 *Glyoxal*

3 Glyoxal is mainly used as a crosslinking agent for vinyl acetate/acrylic resins, disinfectant, gelatin hardening agent,
 4 textile finishing agent (permanent-press cotton, rayon fabrics), and wet-resistance additive (paper coatings) (IPCC
 5 2006). It is also used for enhanced oil-recovery. It is produced from oxidation of acetaldehyde with concentrated
 6 nitric acid, or from the catalytic oxidation of ethylene glycol, and N₂O is emitted in the process of oxidation of
 7 acetaldehyde.

8 Glyoxal (ethanedial) (C₂H₂O₂) is produced from oxidation of acetaldehyde (ethanal) (C₂H₄O) with concentrated
 9 nitric acid (HNO₃). Glyoxal can also be produced from catalytic oxidation of ethylene glycol (ethanediol)
 10 (CH₂OHCH₂OH).

11 *Glyoxylic Acid*

12 Glyoxylic acid is produced by nitric acid oxidation of glyoxal. Glyoxylic acid is used for the production of synthetic
 13 aromas, agrochemicals, and pharmaceutical intermediates (IPCC 2006).

14 EPA does not currently estimate the emissions associated with the production of Glyoxal and Glyoxylic Acid due to
 15 data availability and a lack of publicly available information on the industry in the United States. See Annex 5 for
 16 additional information.

17 **Methodology**

18 Emissions of N₂O from the production of caprolactam were calculated using the estimation methods provided by
 19 the *2006 IPCC Guidelines*. The *2006 IPCC Guidelines* Tier 1 method was used to estimate emissions from
 20 caprolactam production for 1990 through 2019, as shown in this formula:

$$E_{N_2O} = EF \times CP$$

22 where,

- 23 E_{N_2O} = Annual N₂O Emissions (kg)
 24 EF = N₂O emission factor (default) (kg N₂O/metric ton caprolactam produced)
 25 CP = Caprolactam production (metric tons)

26 During the caprolactam production process, N₂O is generated as a byproduct of the high temperature catalytic
 27 oxidation of ammonia (NH₃), which is the first reaction in the series of reactions to produce caprolactam. The
 28 amount of N₂O emissions can be estimated based on the chemical reaction shown above. Based on this formula,
 29 which is consistent with an IPCC Tier 1 approach, approximately 111.1 metric tons of caprolactam are required to
 30 generate one metric ton of N₂O, resulting in an emission factor of 9.0 kg N₂O per metric ton of caprolactam (IPCC
 31 2006). When applying the Tier 1 method, the *2006 IPCC Guidelines* state that it is good practice to assume that
 32 there is no abatement of N₂O emissions and to use the highest default emission factor available in the guidelines.

1 In addition, EPA did not find support for the use of secondary catalysts to reduce N₂O emissions, such as those
 2 employed at nitric acid plants. Thus, the 515 thousand metric tons (kt) of caprolactam produced in 2019 (ACC
 3 2020) resulted in N₂O emissions of approximately 1.4 MMT CO₂ Eq. (5 kt).
 4 The activity data for caprolactam production (see Table 4-34) from 1990 to 2019 were obtained from the American
 5 Chemistry Council's *Guide to the Business of Chemistry* (ACC 2020). EPA will continue to analyze and assess
 6 alternative sources of production data as a quality control measure.

7 **Table 4-34: Caprolactam Production (kt)**

Year	kt
1990	626
2005	795
2015	700
2016	640
2017	545
2018	530
2019	515

8
 9 Carbon dioxide and methane (CH₄) emissions may also occur from the production of caprolactam, but currently the
 10 IPCC does not have methodologies for calculating these emissions associated with caprolactam production.

11 **Uncertainty and Time-Series Consistency – TO BE UPDATED**

12 Estimation of emissions of N₂O from caprolactam production can be treated as analogous to estimation of
 13 emissions of N₂O from nitric acid production. Both production processes involve an initial step of NH₃ oxidation,
 14 which is the source of N₂O formation and emissions (IPCC 2006). Therefore, uncertainties for the default emission
 15 factor values in the *2006 IPCC Guidelines* are an estimate based on default values for nitric acid plants. In general,
 16 default emission factors for gaseous substances have higher uncertainties because mass values for gaseous
 17 substances are influenced by temperature and pressure variations and gases are more easily lost through process
 18 leaks. The default values for caprolactam production have a relatively high level of uncertainty due to the limited
 19 information available (IPCC 2006).

20 The results of this Approach 2 quantitative uncertainty analysis are summarized in Table 4-35. Nitrous oxide
 21 emissions from Caprolactam, Glyoxal and Glyoxylic Acid Production for 2019 were estimated to be between 1.0
 22 and 1.9 MMT CO₂ Eq. at the 95 percent confidence level. These values indicate a range of approximately 32
 23 percent below to 32 percent above the 2019 emission estimate of 1.4 MMT CO₂ Eq.

24 **Table 4-35: Approach 2 Quantitative Uncertainty Estimates for N₂O Emissions from**
 25 **Caprolactam, Glyoxal and Glyoxylic Acid Production (MMT CO₂ Eq. and Percent)**

Source	Gas	2019 Emission Estimate (MMT CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a (MMT CO ₂ Eq.)			
			Lower Bound	Upper Bound	Lower Bound (%)	Upper Bound (%)
Caprolactam Production	N ₂ O	1.4	1.0	1.9	-32%	+32%

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

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

1 QA/QC and Verification

2 General quality assurance/quality control (QA/QC) procedures were applied consistent with the U.S. Inventory
3 QA/QC plan, which is in accordance with Volume 1, Chapter 6 of the *2006 IPCC Guidelines* as described in the
4 introduction of the IPPU chapter (see Annex 8 for more details).

5 Recalculations Discussion

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

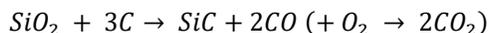
7 Planned Improvements

8 Pending resources, EPA will research other available datasets for caprolactam production and industry trends,
9 including facility-level data. EPA will also research the production process and emissions associated with the
10 production of glyoxal and glyoxylic acid. During the Expert Review period for the current Inventory report, EPA
11 continues to seek expert solicitation on data available for these emission source categories. This planned
12 improvement is subject to data availability and will be implemented in the medium- to long-term.

13 4.10 Carbide Production and Consumption 14 (CRF Source Category 2B5)

15 Carbon dioxide (CO₂) and methane (CH₄) are emitted from the production of silicon carbide (SiC), a material used
16 for industrial abrasive, metallurgical and other non-abrasive applications in the United States. Emissions from fuels
17 consumed for energy purposes during the production of silicon carbide are accounted for in the Energy chapter.

18 To produce SiC, silica sand or quartz (SiO₂) is reacted with carbon (C) in the form of petroleum coke. A portion
19 (about 35 percent of the carbon contained in the petroleum coke is retained in the SiC. The remaining C is emitted
20 as CO₂, CH₄, or carbon monoxide (CO). The overall reaction is shown below, but in practice, it does not proceed
21 according to stoichiometry:



23 Carbon dioxide and CH₄ are also emitted during the production of calcium carbide, a chemical used to produce
24 acetylene. Carbon dioxide is implicitly accounted for in the storage factor calculation for the non-energy use of
25 petroleum coke in the Energy chapter. As noted in Annex 5 to this report, CH₄ emissions from calcium carbide
26 production are not estimated because data are not available. EPA is continuing to investigate the inclusion of these
27 emissions in future Inventory reports.

28 Markets for manufactured abrasives, including SiC, are heavily influenced by activity in the U.S. manufacturing
29 sector, especially in the aerospace, automotive, furniture, housing, and steel manufacturing sectors. The U.S.
30 Geological Survey (USGS) reports that a portion (approximately 50 percent) of SiC is used in metallurgical and
31 other non-abrasive applications, primarily in iron and steel production (USGS 1991a through 2017). As a result of
32 the economic downturn in 2008 and 2009, demand for SiC decreased in those years. Low-cost imports, particularly
33 from China, combined with high relative operating costs for domestic producers, continue to put downward
34 pressure on the production of SiC in the United States. Demand for SiC consumption in the United States has
35 recovered somewhat from its low in 2009 (USGS 1991a through 2015). Abrasive-grade silicon carbide was
36 manufactured at one facility in 2017 in the United States (USGS 2020).

37 Carbon dioxide emissions from SiC production and consumption in 2019 were 0.2 MMT CO₂ Eq. (175 kt CO₂) (see
38 Table 4-36 and Table 4-37). Approximately 52 percent of these emissions resulted from SiC production, while the
39 remainder resulted from SiC consumption. Methane emissions from SiC production in 2019 were 0.01 MMT CO₂

1 Eq. (0.4 kt CH₄) (see Table 4-36 and Table 4-37). Emissions have not fluctuated greatly in recent years, but 2019
 2 emissions are about 50 percent lower than emissions in 1990.

3 **Table 4-36: CO₂ and CH₄ Emissions from Silicon Carbide Production and Consumption (MMT**
 4 **CO₂ Eq.)**

Year	1990	2005	2015	2016	2017	2018	2019
CO ₂	0.4	0.2	0.2	0.2	0.2	0.2	0.2
CH ₄	+	+	+	+	+	+	+
Total	0.4	0.2	0.2	0.2	0.2	0.2	0.2

+ Does not exceed 0.05 MMT CO₂ Eq.

5 **Table 4-37: CO₂ and CH₄ Emissions from Silicon Carbide Production and Consumption (kt)**

Year	1990	2005	2015	2016	2017	2018	2019
CO ₂	370	213	176	170	181	184	175
CH ₄	1	+	+	+	+	+	+

+ Does not exceed 0.5 kt

6 Methodology

7 Emissions of CO₂ and CH₄ from the production of SiC were calculated⁴⁰ using the Tier 1 method provided by the
 8 *2006 IPCC Guidelines*. Annual estimates of SiC production were multiplied by the appropriate emission factor, as
 9 shown below:

$$E_{sc,CO_2} = EF_{sc,CO_2} \times Q_{sc}$$

$$E_{sc,CH_4} = EF_{sc,CH_4} \times Q_{sc} \times \left(\frac{1 \text{ metric ton}}{1000 \text{ kg}} \right)$$

12 where,

13	E_{sc,CO_2}	=	CO ₂ emissions from production of SiC, metric tons
14	EF_{sc,CO_2}	=	Emission factor for production of SiC, metric ton CO ₂ /metric ton SiC
15	Q_{sc}	=	Quantity of SiC produced, metric tons
16	E_{sc,CH_4}	=	CH ₄ emissions from production of SiC, metric tons
17	EF_{sc,CH_4}	=	Emission factor for production of SiC, kilogram CH ₄ /metric ton SiC

18

19 Emission factors were taken from the *2006 IPCC Guidelines*:

- 20 • 2.62 metric tons CO₂/metric ton SiC
- 21 • 11.6 kg CH₄/metric ton SiC

22 Production data for metallurgical and other non-abrasive applications of SiC are not available; therefore, both CO₂
 23 and CH₄ estimates for SiC are based solely upon production data for SiC for industrial abrasive applications.

24 Silicon carbide industrial abrasives production data for 1990 through 2013 were obtained from the U.S. Geological
 25 Survey (USGS) *Minerals Yearbook: Manufactured Abrasives* (USGS 1991a through 2015). Production data for 2014
 26 through 2017 were obtained from the *Mineral Commodity Summaries: Abrasives (Manufactured)* (USGS 2019).
 27 Production data for 2018 and 2019 were obtained from the *Mineral Industry Surveys, Manufactured Abrasives*
 28 (USGS 2019a, USGS 2020a). Silicon carbide production data obtained through the USGS National Minerals

⁴⁰ EPA has not integrated aggregated facility-level GHGRP information to inform these estimates. The aggregated information (e.g., activity data and emissions) associated with silicon carbide did not meet criteria to shield underlying confidential business information (CBI) from public disclosure.

1 Information Center has been rounded to the nearest 5,000 metric tons to avoid disclosing company proprietary
 2 data. SiC consumption for the entire time series is estimated using USGS consumption data (USGS 1991b through
 3 2015, USGS 2017c) and data from the U.S. International Trade Commission (USITC) database on net imports and
 4 exports of SiC provided by the U.S. Census Bureau (2005 through 2020) (see Table 4-38). Total annual SiC
 5 consumption (utilization) was estimated by subtracting annual exports of SiC by the annual total of national SiC
 6 production and net imports.

7 Emissions of CO₂ from SiC consumption for metallurgical uses were calculated by multiplying the annual utilization
 8 of SiC for metallurgical uses (reported annually in the USGS *Minerals Yearbook: Silicon*) by the carbon content of
 9 SiC (30.0 percent), which was determined according to the molecular weight ratio of SiC. USGS has not published
 10 consumption data for metallurgical uses since 2016 due to concerns of disclosing company-specific sensitive
 11 information, and there is uncertainty about the future availability of these data from the USGS. Other options are
 12 being explored that would allow the estimation of SiC consumption for metallurgical uses. The 2016 consumption
 13 data will be used as a proxy until a suitable approach is developed.

14 Emissions of CO₂ from SiC consumption for other non-abrasive uses were calculated by multiplying the annual SiC
 15 consumption for non-abrasive uses by the carbon content of SiC (30 percent). The annual SiC consumption for non-
 16 abrasive uses was calculated by multiplying the annual SiC consumption (production plus net imports) by the
 17 percentage used in metallurgical and other non-abrasive uses (50 percent) (USGS 1991a through 2017) and then
 18 subtracting the SiC consumption for metallurgical use.

19 The petroleum coke portion of the total CO₂ process emissions from silicon carbide production is adjusted for
 20 within the Energy chapter, as these fuels were consumed during non-energy related activities. Additional
 21 information on the adjustments made within the Energy sector for Non-Energy Use of Fuels is described in both
 22 the Methodology section of CO₂ from Fossil Fuel Combustion (Section 3.1) and Annex 2.1, Methodology for
 23 Estimating Emissions of CO₂ from Fossil Fuel Combustion.

24 **Table 4-38: Production and Consumption of Silicon Carbide (Metric Tons)**

Year	Production	Consumption
1990	105,000	172,465
2005	35,000	220,149
2015	35,000	153,475
2016	35,000	142,104
2017	35,000	163,492
2018	35,000	168,531
2019	35,000	152,410

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

27 There is uncertainty associated with the emission factors used because they are based on stoichiometry as
 28 opposed to monitoring of actual SiC production plants. An alternative is to calculate emissions based on the
 29 quantity of petroleum coke used during the production process rather than on the amount of silicon carbide
 30 produced. However, these data were not available. For CH₄, there is also uncertainty associated with the
 31 hydrogen-containing volatile compounds in the petroleum coke (IPCC 2006). There is also uncertainty associated
 32 with the use or destruction of CH₄ generated from the process, in addition to uncertainty associated with levels of
 33 production, net imports, consumption levels, and the percent of total consumption that is attributed to
 34 metallurgical and other non-abrasive uses.

35 The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-39. Silicon carbide
 36 production and consumption CO₂ emissions from 2017 were estimated to be between 10 percent below and 9

percent above the emission estimate of 0.18 MMT CO₂ Eq. at the 95 percent confidence level. Silicon carbide production CH₄ emissions were estimated to be between 9 percent below and 9 percent above the emission estimate of 0.01 MMT CO₂ Eq. at the 95 percent confidence level.

Table 4-39: Approach 2 Quantitative Uncertainty Estimates for CH₄ and CO₂ Emissions from Silicon Carbide Production and Consumption (MMT CO₂ Eq. and Percent)

Source	Gas	2019 Emission Estimate (MMT CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			Lower Bound	Upper Bound	Lower Bound (%)	Upper Bound (%)
Silicon Carbide Production and Consumption	CO ₂	0.18	0.17	0.21	-10%	+9%
Silicon Carbide Production	CH ₄	+	+	+	-9%	+9%

+ Does not exceed 0.05 MMT CO₂ Eq.

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

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

QA/QC and Verification

General quality assurance/quality control (QA/QC) procedures were applied consistent with the U.S. Inventory QA/QC plan, which is in accordance with Volume 1, Chapter 6 of *2006 IPCC Guidelines* as described in the introduction of the IPPU chapter (see Annex 8 for more details).

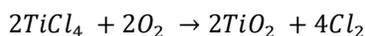
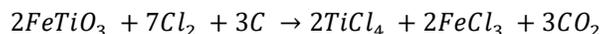
Recalculations Discussion

During annual QC, a transcription error was identified for the percentage of carbon in SiC. The molecular weight value for silicon used in the 1990 through 2018 portion of the time series was 26, which resulted in a percentage of carbon in SiC of 31.5 percent. The molecular weight for silicon is 28, which results in the percentage of carbon in SiC of 30.0 percent. This recalculation was applied to the entire time series for SiC consumption. This change resulted in annual emissions decreases ranging from 3 to 9 kt CO₂ between 1990 and 2018.

The carbon factors used to determine the amount of petroleum coke used for SiC production were updated to be consistent with the factors used in the fossil fuel combustion estimates. This update did not have an impact on process-related SiC emissions presented here but did impact the amount of petroleum coke subtracted from energy use as part of the CO₂ Emissions from Fossil Fuel Combustion calculations (see Annex 2.3 for more information, including impact on trends).

4.11 Titanium Dioxide Production (CRF Source Category 2B6)

Titanium dioxide (TiO₂) is manufactured using one of two processes: the chloride process and the sulfate process. The chloride process uses petroleum coke and chlorine as raw materials and emits process-related carbon dioxide (CO₂). Emissions from fuels consumed for energy purposes during the production of titanium dioxide are accounted for in the Energy chapter. The chloride process is based on the following chemical reactions:



The sulfate process does not use petroleum coke or other forms of carbon as a raw material and does not emit CO₂.

The C in the first chemical reaction is provided by petroleum coke, which is oxidized in the presence of the chlorine and FeTiO₃ (rutile ore) to form CO₂. Since 2004, all TiO₂ produced in the United States has been produced using the chloride process, and a special grade of “calcined” petroleum coke is manufactured specifically for this purpose.

The principal use of TiO₂ is as a pigment in white paint, lacquers, and varnishes. It is also used as a pigment in the manufacture of plastics, paper, and other products. In 2019, U.S. TiO₂ production totaled 1,100,000 metric tons (USGS 2020). There were five plants producing TiO₂ in the United States in 2019.

Emissions of CO₂ from titanium dioxide production in 2019 were estimated to be 1.5 MMT CO₂ Eq. (1,474 kt CO₂), which represents an increase of 23 percent since 1990 (see Table 4-40). Compared to 2018, emissions from titanium dioxide production decreased by 4 percent in 2019, likely due to a 4 percent decrease in production.

Table 4-40: CO₂ Emissions from Titanium Dioxide (MMT CO₂ Eq. and kt)

Year	MMT CO ₂ Eq.	Kt
1990	1.2	1,195
2005	1.8	1,755
2015	1.6	1,635
2016	1.7	1,662
2017	1.7	1,688
2018	1.5	1,541
2019	1.5	1,474

Methodology

Emissions of CO₂ from TiO₂ production were calculated by multiplying annual national TiO₂ production by chloride process-specific emission factors using a Tier 1 approach provided in *2006 IPCC Guidelines*. The Tier 1 equation is as follows:

$$E_{td} = EF_{td} \times Q_{td}$$

where,

E _{td}	=	CO ₂ emissions from TiO ₂ production, metric tons
EF _{td}	=	Emission factor (chloride process), metric ton CO ₂ /metric ton TiO ₂
Q _{td}	=	Quantity of TiO ₂ produced

The petroleum coke portion of the total CO₂ process emissions from TiO₂ production is adjusted for within the Energy chapter as these fuels were consumed during non-energy related activities. Additional information on the adjustments made within the Energy sector for Non-Energy Use of Fuels is described in both the Methodology section of CO₂ from Fossil Fuel Combustion (Section 3.1 Fossil Fuel Combustion) and Annex 2.1, Methodology for Estimating Emissions of CO₂ from Fossil Fuel Combustion.

Data were obtained for the total amount of TiO₂ produced each year. For years prior to 2004, it was assumed that TiO₂ was produced using the chloride process and the sulfate process in the same ratio as the ratio of the total U.S. production capacity for each process. As of 2004, the last remaining sulfate process plant in the United States closed; therefore, 100 percent of production since 2004 used the chloride process (USGS 2005). An emission factor

1 of 1.34 metric tons CO₂/metric ton TiO₂ was applied to the estimated chloride-process production (IPCC 2006). It
2 was assumed that all TiO₂ produced using the chloride process was produced using petroleum coke, although
3 some TiO₂ may have been produced with graphite or other carbon inputs.

4 The emission factor for the TiO₂ chloride process was taken from the 2006 IPCC Guidelines. Titanium dioxide
5 production data and the percentage of total TiO₂ production capacity that is chloride process for 1990 through
6 2013 (see Table 4-41) were obtained through the U.S. Geological Survey (USGS) *Minerals Yearbook: Titanium*
7 *Annual Report* (USGS 1991 through 2015). Production data for 2014 through 2019 were obtained from the
8 *Minerals Commodity Summaries: Titanium and Titanium Dioxide* (USGS 2020).⁴¹ Data on the percentage of total
9 TiO₂ production capacity that is chloride process were not available for 1990 through 1993, so data from the 1994
10 USGS *Minerals Yearbook* were used for these years. Because a sulfate process plant closed in September 2001, the
11 chloride process percentage for 2001 was estimated based on a discussion with Joseph Gambogi (2002). By 2002,
12 only one sulfate process plant remained online in the United States, and this plant closed in 2004 (USGS 2005).

13 **Table 4-41: Titanium Dioxide Production (kt)**

Year	kt
1990	979
2005	1,310
2015	1,220
2016	1,240
2017	1,260
2018	1,150
2019	1,100

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

16 Each year, the USGS collects titanium industry data for titanium mineral and pigment production operations. If
17 TiO₂ pigment plants do not respond, production from the operations is estimated based on prior year production
18 levels and industry trends. Variability in response rates varies from 67 to 100 percent of TiO₂ pigment plants over
19 the time series.

20 Although some TiO₂ may be produced using graphite or other carbon inputs, information and data regarding these
21 practices were not available. Titanium dioxide produced using graphite inputs, for example, may generate differing
22 amounts of CO₂ per unit of TiO₂ produced as compared to that generated using petroleum coke in production.
23 While the most accurate method to estimate emissions would be to base calculations on the amount of reducing
24 agent used in each process rather than on the amount of TiO₂ produced, sufficient data were not available to do
25 so.

26 As of 2004, the last remaining sulfate-process plant in the United States closed. Since annual TiO₂ production was
27 not reported by USGS by the type of production process used (chloride or sulfate) prior to 2004 and only the
28 percentage of total production capacity by process was reported, the percent of total TiO₂ production capacity that
29 was attributed to the chloride process was multiplied by total TiO₂ production to estimate the amount of TiO₂
30 produced using the chloride process. Finally, the emission factor was applied uniformly to all chloride-process
31 production, and no data were available to account for differences in production efficiency among chloride-process

⁴¹ EPA has not integrated aggregated facility-level GHGRP information for Titanium Dioxide production facilities (40 CFR Part 98 Subpart EE). The relevant aggregated information (activity data, emission factor) from these facilities did not meet criteria to shield underlying CBI from public disclosure.

plants. In calculating the amount of petroleum coke consumed in chloride-process TiO₂ production, literature data were used for petroleum coke composition. Certain grades of petroleum coke are manufactured specifically for use in the TiO₂ chloride process; however, this composition information was not available.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-42. Titanium dioxide consumption CO₂ emissions from 2019 were estimated to be between 1.3 and 1.7 MMT CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 12 percent below and 13 percent above the emission estimate of 1.5 MMT CO₂ Eq.

Table 4-42: Approach 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Titanium Dioxide Production (MMT CO₂ Eq. and Percent)

Source	Gas	2019 Emission Estimate (MMT CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			(MMT CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Titanium Dioxide Production	CO ₂	1.5	1.3	1.7	-12%	+13%

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

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

QA/QC and Verification

General quality assurance/quality control (QA/QC) procedures were applied consistent with the U.S. Inventory QA/QC plan, which is in accordance with Volume 1, Chapter 6 of the *2006 IPCC Guidelines* as described in the introduction of the IPPU chapter (see Annex 8 for more details).

Recalculations Discussion

No recalculations were performed for the 1990 through 2018 portion of the time series. The carbon factors used to determine the amount of petroleum coke used for titanium dioxide production were updated to be consistent with the factors used in the fossil fuel combustion estimates. This update did not have an impact on process-related titanium dioxide emissions presented here but did impact the amount of petroleum coke subtracted from energy use as part of the CO₂ Emissions from Fossil Fuel Combustion calculations (see Annex 2.3 for more information).

Planned Improvements

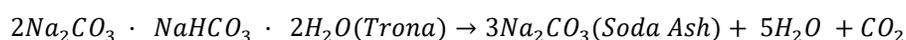
EPA plans to examine the use of GHGRP titanium dioxide emissions data for possible use in emission estimates consistent with both Volume 1, Chapter 6 of the *2006 IPCC Guidelines* and the latest IPCC guidance on the use of facility-level data in national inventories.⁴² This planned improvement is ongoing and has not been incorporated into this Inventory report. This is a long-term planned improvement.

⁴² See <http://www.ipcc-nggip.iges.or.jp/public/tb/TFI_Technical_Bulletin_1.pdf>.

4.12 Soda Ash Production (CRF Source Category 2B7)

Carbon dioxide (CO₂) is generated as a byproduct of calcining trona ore to produce soda ash and is eventually emitted into the atmosphere. In addition, CO₂ may also be released when soda ash is consumed. Emissions from soda ash consumption in chemical production processes are reported under Section 4.4 Other Process Uses of Carbonates (CRF Category 2A4), and emissions from fuels consumed for energy purposes during the production and consumption of soda ash are accounted for in the Energy chapter.

Calcining involves placing crushed trona ore into a kiln to convert sodium bicarbonate into crude sodium carbonate that will later be filtered into pure soda ash. The emission of CO₂ during trona-based production is based on the following reaction:



Soda ash (sodium carbonate, Na₂CO₃) is a white crystalline solid that is readily soluble in water and strongly alkaline. Commercial soda ash is used as a raw material in a variety of industrial processes and in many familiar consumer products such as glass, soap and detergents, paper, textiles, and food. The largest use of soda ash is for glass manufacturing. Emissions from soda ash used in glass production are reported under Section 4.3, Glass Production (CRF Source Category 2A3). In addition, soda ash is used primarily to manufacture many sodium-based inorganic chemicals, including sodium bicarbonate, sodium chromates, sodium phosphates, and sodium silicates (USGS 2018b). Internationally, two types of soda ash are produced: natural and synthetic. The United States produces only natural soda ash and is second only to China in total soda ash production. Trona is the principal ore from which natural soda ash is made.

The United States represents about one-fifth of total world soda ash output (USGS 2020a). Only two states produce natural soda ash: Wyoming and California. Of these two states, net emissions of CO₂ from soda ash production were only calculated for Wyoming, due to specifics regarding the production processes employed in the state.⁴³ Based on 2019 reported data, the estimated distribution of soda ash by end-use in 2019 (excluding glass production) was chemical production, 55 percent; other uses, 14 percent; soap and detergent manufacturing, 11 percent; wholesale distributors (e.g., for use in agriculture, water treatment, and grocery wholesale), 10 percent; flue gas desulfurization, 6 percent; water treatment, 2 percent, and pulp and paper production, 2 percent (USGS 2020b).⁴⁴

U.S. natural soda ash is competitive in world markets because it is generally considered a better-quality raw material than synthetically produced soda ash, and the majority of the world output of soda ash is made synthetically. Although the United States continues to be a major supplier of soda ash, China surpassed the United States in soda ash production in 2003, becoming the world's leading producer.

⁴³ In California, soda ash is manufactured using sodium carbonate-bearing brines instead of trona ore. To extract the sodium carbonate, the complex brines are first treated with CO₂ in carbonation towers to convert the sodium carbonate into sodium bicarbonate, which then precipitates from the brine solution. The precipitated sodium bicarbonate is then calcined back into sodium carbonate. Although CO₂ is generated as a byproduct, the CO₂ is recovered and recycled for use in the carbonation stage and is not emitted. A third state, Colorado, produced soda ash until the plant was idled in 2004. The lone producer of sodium bicarbonate no longer mines trona ore in the state. For a brief time, sodium bicarbonate was produced using soda ash feedstocks mined in Wyoming and shipped to Colorado. Prior to 2004, because the trona ore was mined in Wyoming, the production numbers given by the USGS included the feedstocks mined in Wyoming and shipped to Colorado. In this way, the sodium bicarbonate production that took place in Colorado was accounted for in the Wyoming numbers.

⁴⁴ Percentages may not add up to 100 percent due to independent rounding.

1 In 2019, CO₂ emissions from the production of soda ash from trona ore were 1.8 MMT CO₂ Eq. (1,792 kt CO₂) (see
2 Table 4-43). Total emissions from soda ash production in 2019 increased by approximately 5 percent from
3 emissions in 2018 and have increased by approximately 25 percent from 1990 levels.

4 Emissions have remained relatively constant over the time series with some fluctuations since 1990. In general,
5 these fluctuations were related to the behavior of the export market and the U.S. economy. The U.S. soda ash
6 industry continued a trend of increased production and value in 2019 since experiencing a decline in domestic and
7 export sales caused by adverse global economic conditions in 2009.

8 **Table 4-43: CO₂ Emissions from Soda Ash Production (MMT CO₂ Eq. and kt CO₂)**

Year	MMT CO ₂ Eq.	kt CO ₂
1990	1.4	1,431
2005	1.7	1,655
2015	1.7	1,714
2016	1.7	1,723
2017	1.8	1,753
2018	1.7	1,714
2019	1.8	1,792

9 Methodology

10 During the soda ash production process, trona ore is calcined in a rotary kiln and chemically transformed into a
11 crude soda ash that requires further processing. Carbon dioxide and water are generated as byproducts of the
12 calcination process. Carbon dioxide emissions from the calcination of trona ore can be estimated based on the
13 chemical reaction shown above. Based on this formula, which is consistent with an IPCC Tier 1 approach,
14 approximately 10.27 metric tons of trona ore are required to generate one metric ton of CO₂, or an emission factor
15 of 0.0974 metric tons CO₂ per metric ton of trona ore (IPCC 2006). Thus, the 18.4 million metric tons of trona ore
16 mined in 2019 for soda ash production (USGS 2020b) resulted in CO₂ emissions of approximately 1.8 MMT CO₂ Eq.
17 (1,792 kt).

18 Once produced, most soda ash is consumed in chemical production, with minor amounts used in soap production,
19 pulp and paper, flue gas desulfurization, and water treatment (excluding soda ash consumption for glass
20 manufacturing). As soda ash is consumed for these purposes, additional CO₂ is usually emitted. Consistent with the
21 *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, emissions from soda ash consumption in chemical
22 production processes are reported under Section 4.4 Other Process Uses of Carbonates (CRF Category 2A4).

23 Data is not currently available for the quantity of trona used in soda ash production. Trona ore produced is used
24 primarily for soda ash production, and for the current Inventory report, EPA assumes that all trona produced was
25 used in soda ash production. The activity data for trona ore production (see Table 4-44) for 1990 through 2019
26 were obtained from the U.S. Geological Survey (USGS) *Minerals Yearbook for Soda Ash* (1994 through 2015b) and
27 USGS *Mineral Industry Surveys for Soda Ash* (USGS 2016 through 2017, 2018a, 2019, 2020b). Soda ash
28 production⁴⁵ data were collected by the USGS from voluntary surveys of the U.S. soda ash industry. EPA will
29 continue to analyze and assess opportunities to use facility-level data from EPA's GHGRP to improve the emission
30 estimates for the Soda Ash Production source category consistent with IPCC⁴⁶ and UNFCCC guidelines.

⁴⁵ EPA has assessed the feasibility of using emissions information (including activity data) from EPA's GHGRP program. At this time, the aggregated information associated with production of soda ash did not meet criteria to shield underlying confidential business information (CBI) from public disclosure.

⁴⁶ See <http://www.ipcc-nggip.iges.or.jp/public/tb/TFI_Technical_Bulletin_1.pdf>.

1 **Table 4-44: Trona Ore Use (kt)**

Year	Use ^a
1990	14,700
2005	17,000
2015	17,600
2016	17,700
2017	18,000
2018	17,600
2019	18,400

^a Trona ore use is assumed to be equal to trona ore production.

2 **Uncertainty and Time-Series Consistency – TO BE UPDATED**

3 Emission estimates from soda ash production have relatively low associated uncertainty levels because reliable
 4 and accurate data sources are available for the emission factor and activity data for trona-based soda ash
 5 production. One source of uncertainty is the purity of the trona ore used for manufacturing soda ash. The emission
 6 factor used for this estimate assumes the ore is 100 percent pure, and likely overestimates the emissions from
 7 soda ash manufacture. The average water-soluble sodium carbonate-bicarbonate content for ore mined in
 8 Wyoming ranges from 85.5 to 93.8 percent (USGS 1995c).

9 EPA is aware of one facility producing soda ash from a liquid alkaline feedstock process based on EPA’s GHGRP.
 10 Soda ash production data was collected by the USGS from voluntary surveys. A survey request was sent to each of
 11 the five soda ash producers, all of which responded, representing 100 percent of the total production data (USGS
 12 2020b).

13 The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-45. Soda ash production
 14 CO₂ emissions for 2019 were estimated to be between 1.5 and 1.8 MMT CO₂ Eq. at the 95 percent confidence
 15 level. This indicates a range of approximately 9 percent below and 8 percent above the emission estimate of 1.8
 16 MMT CO₂ Eq.

17 **Table 4-45: Approach 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Soda Ash**
 18 **Production (MMT CO₂ Eq. and Percent)**

Source	Gas	2019 Emission Estimate	Uncertainty Range Relative to Emission Estimate ^a			
		(MMT CO ₂ Eq.)	(MMT CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Soda Ash Production	CO ₂	1.8	1.5	1.8	-9%	+8%

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

19 Methodological approaches were applied to the entire time series to ensure consistency in emissions estimates
 20 from 1990 through 2019.

21 **QA/QC and Verification**

22 General quality assurance/quality control (QA/QC) procedures were applied consistent with the U.S. Inventory
 23 QA/QC plan, which is in accordance with Volume 1, Chapter 6 of *2006 IPCC Guidelines* as described in the
 24 introduction of the IPPU chapter (see Annex 8 for more details).

1 Recalculations Discussion

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

3 Planned Improvements

4 EPA plans to review USGS data to improve use of activity data to estimate emissions, consistent with the
5 methodological decision trees in *2006 IPCC Guidelines*. EPA also plans to use GHGRP data for conducting category-
6 specific QC of emission estimates, consistent with both Volume 1, Chapter 6 of the *2006 IPCC Guidelines* and the
7 latest IPCC guidance on the use of facility-level data in national inventories.⁴⁷ This planned improvement is
8 ongoing and has not been incorporated into this Inventory report. This is a medium-term planned improvement
9 and expected to be completed by the next (i.e., 2021) Inventory submission.

10 4.13 Petrochemical Production (CRF Source 11 Category 2B8)

12 The production of some petrochemicals results in the release of carbon dioxide (CO₂) and methane (CH₄)
13 emissions. Petrochemicals are chemicals isolated or derived from petroleum or natural gas. Carbon dioxide
14 emissions from the production of acrylonitrile, carbon black, ethylene, ethylene dichloride, ethylene oxide, and
15 methanol, and CH₄ emissions from the production of methanol and acrylonitrile are presented here and reported
16 under IPCC Source Category 2B8. The petrochemical industry uses primary fossil fuels (i.e., natural gas, coal,
17 petroleum, etc.) for non-fuel purposes in the production of carbon black and other petrochemicals. Emissions from
18 fuels and feedstocks transferred out of the system for use in energy purposes (e.g., indirect or direct process heat
19 or steam production) are currently accounted for in the Energy sector. The allocation and reporting of emissions
20 from feedstocks transferred out of the system for use in energy purposes to the Energy chapter is consistent with
21 the *2006 IPCC Guidelines*.

22 Worldwide, more than 90 percent of acrylonitrile (vinyl cyanide, C₃H₃N) is made by way of direct ammoxidation of
23 propylene with ammonia (NH₃) and oxygen over a catalyst. This process is referred to as the SOHIO process,
24 named after the Standard Oil Company of Ohio (SOHIO) (IPCC 2006). The primary use of acrylonitrile is as the raw
25 material for the manufacture of acrylic and modacrylic fibers. Other major uses include the production of plastics
26 (acrylonitrile-butadiene-styrene [ABS] and styrene-acrylonitrile [SAN]), nitrile rubbers, nitrile barrier resins,
27 adiponitrile, and acrylamide. All U.S. acrylonitrile facilities use the SOHIO process (AN 2014). The SOHIO process
28 involves a fluidized bed reaction of chemical-grade propylene, ammonia, and oxygen over a catalyst. The process
29 produces acrylonitrile as its primary product, and the process yield depends on the type of catalyst used and the
30 process configuration. The ammoxidation process produces byproduct CO₂, carbon monoxide (CO), and water
31 from the direct oxidation of the propylene feedstock and produces other hydrocarbons from side reactions.

32 Carbon black is a black powder generated by the incomplete combustion of an aromatic petroleum- or coal-based
33 feedstock at a high temperature. Most carbon black produced in the United States is added to rubber to impart
34 strength and abrasion resistance, and the tire industry is by far the largest consumer. The other major use of
35 carbon black is as a pigment. The predominant process used in the United States to produce carbon black is the
36 furnace black (or oil furnace) process. In the furnace black process, carbon black oil (a heavy aromatic liquid) is
37 continuously injected into the combustion zone of a natural gas-fired furnace. Furnace heat is provided by the
38 natural gas and a portion of the carbon black feedstock; the remaining portion of the carbon black feedstock is
39 pyrolyzed to carbon black. The resultant CO₂ and uncombusted CH₄ emissions are released from thermal
40 incinerators used as control devices, process dryers, and equipment leaks. Three facilities in the United States use

⁴⁷ See <http://www.ipcc-nggip.iges.or.jp/public/tb/TFI_Technical_Bulletin_1.pdf>.

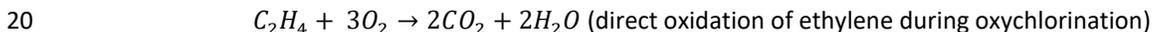
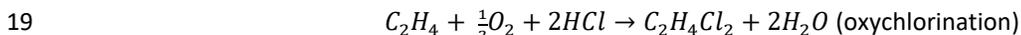
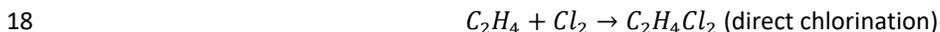
1 other types of carbon black processes. Specifically, one facility produces carbon black by the thermal cracking of
2 acetylene-containing feedstocks (i.e., acetylene black process), a second facility produces carbon black by the
3 thermal cracking of other hydrocarbons (i.e., thermal black process), and a third facility produces carbon black by
4 the open burning of carbon black feedstock (i.e., lamp black process) (EPA 2000).

5 Ethylene (C₂H₄) is consumed in the production processes of the plastics industry including polymers such as high,
6 low, and linear low density polyethylene (HDPE, LDPE, LLDPE); polyvinyl chloride (PVC); ethylene dichloride;
7 ethylene oxide; and ethylbenzene. Virtually all ethylene is produced from steam cracking of ethane, propane,
8 butane, naphtha, gas oil, and other feedstocks. The representative chemical equation for steam cracking of ethane
9 to ethylene is shown below:



11 Small amounts of CH₄ are also generated from the steam cracking process. In addition, CO₂ and CH₄ emissions are
12 also generated from combustion units.

13 Ethylene dichloride (C₂H₄Cl₂) is used to produce vinyl chloride monomer, which is the precursor to polyvinyl
14 chloride (PVC). Ethylene dichloride was also used as a fuel additive until 1996 when leaded gasoline was phased
15 out. Ethylene dichloride is produced from ethylene by either direct chlorination, oxychlorination, or a combination
16 of the two processes (i.e., the “balanced process”); most U.S. facilities use the balanced process. The direct
17 chlorination and oxychlorination reactions are shown below:



21 In addition to the byproduct CO₂ produced from the direct oxidation of the ethylene feedstock, CO₂ and CH₄
22 emissions are also generated from combustion units.

23 Ethylene oxide (C₂H₄O) is used in the manufacture of glycols, glycol ethers, alcohols, and amines. Approximately 70
24 percent of ethylene oxide produced worldwide is used in the manufacture of glycols, including monoethylene
25 glycol. Ethylene oxide is produced by reacting ethylene with oxygen over a catalyst. The oxygen may be supplied to
26 the process through either an air (air process) or a pure oxygen stream (oxygen process). The byproduct CO₂ from
27 the direct oxidation of the ethylene feedstock is removed from the process vent stream using a recycled carbonate
28 solution, and the recovered CO₂ may be vented to the atmosphere or recovered for further utilization in other
29 sectors, such as food production (IPCC 2006). The combined ethylene oxide reaction and byproduct CO₂ reaction is
30 exothermic and generates heat, which is recovered to produce steam for the process. The ethylene oxide process
31 also produces other liquid and off-gas byproducts (e.g., ethane, etc.) that may be burned for energy recovery
32 within the process. Almost all facilities, except one in Texas, use the oxygen process to manufacture ethylene oxide
33 (EPA 2008).

34 Methanol (CH₃OH) is a chemical feedstock most often converted into formaldehyde, acetic acid and olefins. It is
35 also an alternative transportation fuel, as well as an additive used by municipal wastewater treatment facilities in
36 the denitrification of wastewater. Methanol is most commonly synthesized from a synthesis gas (i.e., “syngas” – a
37 mixture containing H₂, CO, and CO₂) using a heterogeneous catalyst. There are a number of process techniques
38 that can be used to produce syngas. Worldwide, steam reforming of natural gas is the most common method;
39 most methanol producers in the United States also use steam reforming of natural gas to produce syngas. Other
40 syngas production processes in the United States include partial oxidation of natural gas and coal gasification.

41 Emissions of CO₂ and CH₄ from petrochemical production in 2018 were 29.4 MMT CO₂ Eq. (29,424 kt CO₂) and 0.3
42 MMT CO₂ Eq. (12 kt CH₄), respectively (see Table 4-46 and Table 4-47). Since 1990, total CO₂ emissions from
43 petrochemical production increased by 36 percent. Carbon dioxide emissions from petrochemical production are
44 driven primarily from ethylene, while CH₄ emissions are mainly from methanol production. Emissions from
45 methanol production reached a low in 2011, given declining methanol production; however, emissions have been
46 increasing every year since 2011 and are now 53 percent greater than in 1990 (though still 4 percent less than the
47 peak of 4.0 MMT CO₂ Eq. in 1997) due to a rebound in methanol production.

1 **Table 4-46: CO₂ and CH₄ Emissions from Petrochemical Production (MMT CO₂ Eq.)**

Year	1990	2005	2015	2016	2017	2018	2019
Total CO₂	21.6	27.4	28.1	28.3	28.9	29.3	30.8
Carbon Black	3.4	4.3	3.3	3.2	3.3	3.4	3.3
Ethylene	13.1	19.0	20.1	19.8	20.0	19.4	20.7
Ethylene Dichloride	0.3	0.5	0.4	0.4	0.4	0.4	0.5
Methanol	2.5	0.8	2.1	2.8	2.9	3.5	3.8
Ethylene Oxide	1.1	1.5	1.2	1.1	1.3	1.3	1.4
Acrylonitrile	1.2	1.3	1.1	1.0	1.0	1.3	1.1
Total CH₄	0.2	0.1	0.2	0.2	0.3	0.3	0.3
Methanol	0.2	0.1	0.2	0.2	0.2	0.3	0.3
Acrylonitrile	+	+	+	+	+	+	+
Total	21.8	27.5	28.2	28.6	29.2	29.7	29.9

+ Does not exceed 0.05 MMT CO₂ Eq.

Note: Totals may not sum due to independent rounding.

2 **Table 4-47: CO₂ and CH₄ Emissions from Petrochemical Production (kt)**

Year	1990	2005	2015	2016	2017	2018	2019
Total CO₂	21,611	27,383	28,062	28,310	28,910	29,314	30,792
Carbon Black	3,381	4,269	3,260	3,160	3,330	3,440	3,300
Ethylene	13,126	19,024	20,100	19,800	20,000	19,400	20,700
Ethylene Dichloride	254	455	398	447	412	440	503
Methanol	2,513	821	2,054	2,848	2,878	3,484	3,839
Ethylene Oxide	1,123	1,489	1,200	1,100	1,250	1,300	1,370
Acrylonitrile	1,214	1,325	1,050	955	1,040	1,250	1,080
Total CH₄	9	3	7	10	10	12	13
Methanol	9	3	7	10	10	12	13
Acrylonitrile	+	+	+	+	+	+	+

+ Does not exceed 0.5 kt CH₄.

Note: Totals may not sum due to independent rounding.

3 Methodology

4 Emissions of CO₂ and CH₄ were calculated using the estimation methods provided by the *2006 IPCC Guidelines* and
 5 country-specific methods from EPA's GHGRP. The *2006 IPCC Guidelines* Tier 1 method was used to estimate CO₂
 6 and CH₄ emissions from production of acrylonitrile and methanol,⁴⁸ and a country-specific approach similar to the
 7 IPCC Tier 2 method was used to estimate CO₂ emissions from production of carbon black, ethylene oxide, ethylene,
 8 and ethylene dichloride. The Tier 2 method for petrochemicals is a total feedstock carbon (C) mass balance
 9 method used to estimate total CO₂ emissions, but it is not applicable for estimating CH₄ emissions.

10 As noted in the *2006 IPCC Guidelines*, the total feedstock C mass balance method (Tier 2) is based on the
 11 assumption that all of the C input to the process is converted either into primary and secondary products or into
 12 CO₂. Further, the guideline states that while the total C mass balance method estimates total C emissions from the
 13 process, it does not directly provide an estimate of the amount of the total C emissions emitted as CO₂, CH₄, or
 14 non-CH₄ volatile organic compounds (NMVOCs). This method accounts for all the C as CO₂, including CH₄.

15 Note, a small subset of facilities reporting under EPA's GHGRP use Continuous Emission Monitoring Systems
 16 (CEMS) to monitor CO₂ emissions from process vents and/or stacks from stationary combustion units, these
 17 facilities are required to also report CO₂, CH₄ and N₂O emissions from combustion of process off-gas in flares. The

⁴⁸ EPA has not integrated aggregated facility-level GHGRP information for acrylonitrile and methanol production. The aggregated information associated with production of these petrochemicals did not meet criteria to shield underlying CBI from public disclosure.

1 CO₂ from flares are included in aggregated CO₂ results. Preliminary analysis of aggregated annual reports shows
2 that flared CH₄ and N₂O emissions are less than 500 kt CO₂ Eq./year. EPA's GHGRP is still reviewing these data
3 across reported years, and EPA plans to address this more completely in future reports.

4 **Carbon Black, Ethylene, Ethylene Dichloride, and Ethylene Oxide**

5 **2010 through 2019**

6 Carbon dioxide emissions and national production were aggregated directly from EPA's GHGRP dataset for 2010
7 through 2019 (EPA 2019, 2020). In 2019, data reported to the GHGRP included CO₂ emissions of 3,300,000 metric
8 tons from carbon black production; 20,700,000 metric tons of CO₂ from ethylene production; 503,000 metric tons
9 of CO₂ from ethylene dichloride production; and 1,370,000 metric tons of CO₂ from ethylene oxide production.
10 These emissions reflect application of a country-specific approach similar to the IPCC Tier 2 method and were used
11 to estimate CO₂ emissions from the production of carbon black, ethylene, ethylene dichloride, and ethylene oxide.

12 Since 2010, EPA's GHGRP, under Subpart X, requires all domestic producers of petrochemicals to report annual
13 emissions and supplemental emissions information (e.g., production data, etc.) to facilitate verification of reported
14 emissions. Under EPA's GHGRP, most petrochemical production facilities are required to use either a mass balance
15 approach or CEMS to measure and report emissions for each petrochemical process unit to estimate facility-level
16 process CO₂ emissions; ethylene production facilities also have a third option. The mass balance method is used by
17 most facilities⁴⁹ and assumes that all the carbon input is converted into primary and secondary products,
18 byproducts, or is emitted to the atmosphere as CO₂. To apply the mass balance, facilities must measure the volume
19 or mass of each gaseous and liquid feedstock and product, mass rate of each solid feedstock and product, and
20 carbon content of each feedstock and product for each process unit and sum for their facility. To apply the
21 optional combustion methodology, ethylene production facilities must measure the quantity, carbon content, and
22 molecular weight of the fuel to a stationary combustion unit when that fuel includes any ethylene process off-gas.
23 These data are used to calculate the total CO₂ emissions from the combustion unit. The facility must also estimate
24 the fraction of the emissions that is attributable to burning the ethylene process off-gas portion of the fuel. This
25 fraction is multiplied by the total emissions to estimate the emissions from ethylene production. The QA/QC and
26 Verification section below has a discussion of non-CO₂ emissions from ethylene production facilities.

27 All non-energy uses of residual fuel and some non-energy uses of "other oil" are assumed to be used in the
28 production of carbon black; therefore, consumption of these fuels is adjusted for within the Energy chapter to
29 avoid double-counting of emissions from fuel used in the carbon black production presented here within IPPU
30 sector. Additional information on the adjustments made within the Energy sector for Non-Energy Use of Fuels is
31 described in both the Methodology section of CO₂ from Fossil Fuel Combustion (3.1 Fossil Fuel Combustion (IPCC
32 Source Category 1A)) and Annex 2.1, Methodology for Estimating Emissions of CO₂ from Fossil Fuel Combustion.

33 **1990 through 2009**

34 Prior to 2010, for each of these 4 types of petrochemical processes, an average national CO₂ emission factor was
35 calculated based on the GHGRP data and applied to production for earlier years in the time series (i.e., 1990
36 through 2009) to estimate CO₂ emissions from carbon black, ethylene, ethylene dichloride, and ethylene oxide
37 production. For carbon black, ethylene, ethylene dichloride, and ethylene oxide carbon dioxide emission factors
38 were derived from EPA's GHGRP data by dividing annual CO₂ emissions for petrochemical type "i" with annual
39 production for petrochemical type "i" and then averaging the derived emission factors obtained for each calendar
40 year 2010 through 2013 (EPA 2019). The years 2010 through 2013 were used in the development of carbon dioxide
41 emission factors as these years are more representative of operations in 1990 through 2009 for these facilities.
42 The average emission factors for each petrochemical type were applied across all prior years because

⁴⁹ A few facilities producing ethylene dichloride, ethylene, and methanol used CO₂ CEMS; those CO₂ emissions have been included in the aggregated GHGRP emissions presented here..

1 petrochemical production processes in the United States have not changed significantly since 1990, though some
 2 operational efficiencies have been implemented at facilities over the time series.

3 The average country-specific CO₂ emission factors that were calculated from the GHGRP data are as follows:

- 4 • 2.59 metric tons CO₂/metric ton carbon black produced
- 5 • 0.79 metric tons CO₂/metric ton ethylene produced
- 6 • 0.040 metric tons CO₂/metric ton ethylene dichloride produced
- 7 • 0.46 metric tons CO₂/metric ton ethylene oxide produced

8
 9 Annual production data for carbon black for 1990 through 2009 were obtained from the International Carbon
 10 Black Association (Johnson 2003 and 2005 through 2010). Annual production data for ethylene, ethylene
 11 dichloride, and ethylene oxide for 1990 through 2009 were obtained from the American Chemistry Council's
 12 (ACC's) *Business of Chemistry* (ACC 2020).

13 Acrylonitrile

14 Carbon dioxide and methane emissions from acrylonitrile production were estimated using the Tier 1 method in
 15 the *2006 IPCC Guidelines*. Annual acrylonitrile production data were used with IPCC default Tier 1 CO₂ and CH₄
 16 emission factors to estimate emissions for 1990 through 2019. Emission factors used to estimate acrylonitrile
 17 production emissions are as follows:

- 18 • 0.18 kg CH₄/metric ton acrylonitrile produced
- 19 • 1.00 metric tons CO₂/metric ton acrylonitrile produced

20
 21 Annual acrylonitrile production data for 1990 through 2019 were obtained from ACC's *Business of Chemistry* (ACC
 22 2020).

23 Methanol

24 Carbon dioxide and methane emissions from methanol production were estimated using the Tier 1 method in the
 25 *2006 IPCC Guidelines*. Annual methanol production data were used with IPCC default Tier 1 CO₂ and CH₄ emission
 26 factors to estimate emissions for 1990 through 2019. Emission factors used to estimate methanol production
 27 emissions are as follows:

- 28 • 2.3 kg CH₄/metric ton methanol produced
- 29 • 0.67 metric tons CO₂/metric ton methanol produced

30
 31 Annual methanol production data for 1990 through 2019 were obtained from the ACC's *Business of Chemistry* (ACC
 32 2020).

33 **Table 4-48: Production of Selected Petrochemicals (kt)**

Chemical	1990	2005	2015	2016	2017	2018	2019
Carbon Black	1,310	1,650	1,220	1,190	1,240	1,280	1,210
Ethylene	16,500	24,000	26,900	26,600	27,800	30,500	32,400
Ethylene Dichloride	6,280	11,300	11,300	11,700	12,400	12,500	12,600
Ethylene Oxide	2,430	3,220	3,240	3,270	3,350	3,310	3,800
Acrylonitrile	1,210	1,330	1,050	955	1,040	1,250	1,080
Methanol	3,750	1,230	3,070	4,250	4,300	5,200	5,730

34 As noted earlier in the introduction section of the Petrochemical Production chapter, the allocation and reporting
 35 of emissions from both fuels and feedstocks transferred out of the system for use in energy purposes to the Energy
 36 chapter differs slightly from the *2006 IPCC Guidelines*. According to the *2006 IPCC Guidelines*, emissions from fuel
 37 combustion from petrochemical production should be allocated to this source category within the IPPU chapter.

1 Due to national circumstances, EIA data on primary fuel for feedstock use within the energy balance are presented
 2 by commodity only, with no resolution on data by industry sector (i.e., petrochemical production). In addition,
 3 under EPA’s GHGRP, reporting facilities began reporting in 2014 on annual feedstock quantities for mass balance
 4 and CEMS methodologies (79 FR 63794), as well as the annual average carbon content of each feedstock (and
 5 molecular weight for gaseous feedstocks) for the mass balance methodology beginning in reporting year 2017 (81
 6 FR 89260).⁵⁰ The United States is currently unable to report non-energy fuel use from petrochemical production
 7 under the IPPU chapter due to CBI issues. Therefore, consistent with *2006 IPCC Guidelines*, fuel consumption data
 8 reported by EIA are modified to account for these overlaps to avoid double-counting. More information on the
 9 non-energy use of fossil fuel feedstocks for petrochemical production can be found in Annex 2.3.

10 Uncertainty and Time-Series Consistency – TO BE UPDATED 11 FOR FINAL REPORT

12 The CH₄ and CO₂ emission factors used for acrylonitrile and methanol production are based on a limited number of
 13 studies. Using plant-specific factors instead of default or average factors could increase the accuracy of the
 14 emission estimates; however, such data were not available for the current Inventory report.

15 The results of the quantitative uncertainty analysis for the CO₂ emissions from carbon black production, ethylene,
 16 ethylene dichloride, and ethylene oxide are based on reported GHGRP data. Refer to the Methodology section for
 17 more details on how these emissions were calculated and reported to EPA’s GHGRP. There is some uncertainty in
 18 the applicability of the average emission factors for each petrochemical type across all prior years. While
 19 petrochemical production processes in the United States have not changed significantly since 1990, some
 20 operational efficiencies have been implemented at facilities over the time series.

21 The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-49. Petrochemical
 22 production CO₂ emissions from 2018 were estimated to be between 27.8 and 31.1 MMT CO₂ Eq. at the 95 percent
 23 confidence level. This indicates a range of approximately 6 percent below to 6 percent above the emission
 24 estimate of 29.4 MMT CO₂ Eq. Petrochemical production CH₄ emissions from 2018 were estimated to be between
 25 0.11 and 0.37 MMT CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 57 percent
 26 below to 46 percent above the emission estimate of 0.3 MMT CO₂ Eq.

27 **Table 4-49: Approach 2 Quantitative Uncertainty Estimates for CH₄ Emissions from
 28 Petrochemical Production and CO₂ Emissions from Petrochemical Production (MMT CO₂ Eq.
 29 and Percent)**

Source	Gas	2018 Emission Estimate (MMT CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			(MMT CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Petrochemical Production	CO ₂	29.4	27.8	31.1	-6%	+6%
Petrochemical Production	CH ₄	0.30	0.11	0.37	-57%	+46%

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

30 Methodological approaches were applied to the entire time series to ensure consistency in emissions from 1990
 31 through 2018.

⁵⁰ See <<https://www.epa.gov/ghgreporting/historical-rulemakings>>.

1 QA/QC and Verification

2 For Petrochemical Production, QA/QC activities were conducted consistent with the U.S. Inventory QA/QC plan, as
3 described in the QA/QC and Verification Procedures section of the IPPU chapter and Annex 8. Source-specific
4 quality control measures for this category included the QA/QC requirements and verification procedures of EPA's
5 GHGRP. More details on the greenhouse gas calculation, monitoring and QA/QC methods applicable to
6 petrochemical facilities can be found under Subpart X (Petrochemical Production) of the regulation (40 CFR Part
7 98).⁵¹ EPA verifies annual facility-level GHGRP reports through a multi-step process (e.g., combination of electronic
8 checks and manual reviews) to identify potential errors and ensure that data submitted to EPA are accurate,
9 complete, and consistent (EPA 2015).⁵² Based on the results of the verification process, EPA follows up with
10 facilities to resolve mistakes that may have occurred. The post-submittals checks are consistent with a number of
11 general and category-specific QC procedures, including range checks, statistical checks, algorithm checks, and year-
12 to-year checks of reported data and emissions. EPA also conducts QA checks of GHGRP reported production data
13 by petrochemical type against external datasets.

14 For ethylene, ethylene dichloride, and ethylene oxide it is possible to compare CO₂ emissions calculated using the
15 GHGRP data to the CO₂ emissions that would have been calculated using the Tier 1 approach if GHGRP data were
16 not available. For ethylene, the GHGRP emissions typically are within 5 percent of the emissions calculated using
17 the Tier 1 approach (except for 2018 and 2019 when the differences were 18 percent and 17 percent,
18 respectively). For ethylene dichloride, the GHGRP emissions are typically within 25 percent of the Tier 1 emissions.
19 For ethylene oxide, GHGRP emissions vary from 17 percent less than the Tier 1 emissions to 20 percent more than
20 the Tier 1 emissions, depending on the year.

21 EPA's GHGRP mandates that all petrochemical production facilities report their annual emissions of CO₂, CH₄, and
22 N₂O from each of their petrochemical production processes. Source-specific quality control measures for the
23 Petrochemical Production category included the QA/QC requirements and verification procedures of EPA's GHGRP.
24 The QA/QC requirements differ depending on the calculation methodology used.

25 As part of a planned improvement effort, EPA has assessed the potential of using GHGRP data to estimate CH₄
26 emissions from ethylene production. As discussed in the Methodology section above, CO₂ emissions from ethylene
27 production in this chapter are based on data reported under the GHGRP, and these emissions are calculated using
28 a Tier 2 approach that assumes all of the carbon in the fuel (i.e., ethylene process off-gas) is converted to CO₂.
29 Ethylene production facilities also calculate and report CH₄ emissions under the GHGRP when they use the optional
30 combustion methodology. The facilities calculate CH₄ emissions from each combustion unit that burns off-gas from
31 an ethylene production process unit using a Tier 1 approach based on the total quantity of fuel burned, a default
32 higher heating value, and a default emission factor. Because multiple other types of fuel in addition to the ethylene
33 process unit off-gas may be burned in these combustion units, the facilities also report an estimate of the fraction
34 of emissions that is due to burning the ethylene process off-gas component of the total fuel. Multiplying the total
35 emissions by the estimated fraction provides an estimate of the CH₄ emissions from the ethylene production
36 process unit. These ethylene production facilities also calculate CH₄ emissions from flares that burn process vent
37 emissions from ethylene processes. The emissions are calculated using either a Tier 2 approach based on
38 measured gas volumes and measured carbon content or higher heating value, or a Tier 1 approach based on the
39 measured gas flow and a default emission factor. Nearly all ethylene production facilities use the optional
40 combustion methodology under the GHGRP, and the sum of reported CH₄ emissions from combustion in stationary
41 combustion units and flares at all of these facilities is on the same order of magnitude as the combined CH₄
42 emissions presented in this chapter from methanol and acrylonitrile production. The CH₄ emissions from ethylene
43 production under the GHGRP have not been included in this chapter because this approach double counts carbon
44 (i.e., all of the carbon in the CH₄ emissions is also included in the CO₂ emissions from the ethylene process units).

⁵¹ See <http://www.ecfr.gov/cgi-bin/text-idx?tpl=/ecfrbrowse/Title40/40cfr98_main_02.tpl>.

⁵² See <https://www.epa.gov/sites/production/files/2015-07/documents/ghgrp_verification_factsheet.pdf>.

1 EPA continues to assess the GHGRP data for ways to better disaggregate the data and incorporate it into the
2 inventory.

3 These facilities are also required to report emissions of N₂O from combustion of ethylene process off-gas in both
4 stationary combustion units and flares. Facilities using CEMS (consistent with a Tier 3 approach) are also required
5 to report emissions of CH₄ and N₂O from combustion of petrochemical process-off gases in flares. Preliminary
6 analysis of the aggregated reported CH₄ and N₂O emissions from facilities using CEMS and N₂O emissions from
7 facilities using the optional combustion methodology suggests that these annual emissions are less than 500 kt/yr,
8 which is not significant enough to prioritize for inclusion in the report at this time. Pending resources and
9 significance, EPA may include these N₂O emissions in future reports to enhance completeness.

10 Future QC efforts to validate the use of Tier 1 default emission factors and report on the comparison of Tier 1
11 emission estimates and GHGRP data are described below in the Planned Improvements section.

12 Recalculations Discussion

13 The 2018 data for production and emissions from carbon black, ethylene, ethylene dichloride, and ethylene oxide
14 have been updated with updated GHGRP data for 2018 for this Inventory (EPA 2020). These changes resulted in a
15 0.4 percent decrease in total petrochemical emissions for 2018, compared to the previous Inventory.

16 Planned Improvements

17 Improvements include completing category-specific QC of activity data and emission factors, along with further
18 assessment of CH₄ and N₂O emissions to enhance completeness in reporting of emissions from U.S. petrochemical
19 production, pending resources, significance and time-series consistency considerations. For example, EPA is
20 planning additional assessment of ways to use CH₄ data from the GHGRP in the Inventory. One possible approach
21 EPA is assessing would be to adjust the CO₂ emissions from the GHGRP downward by subtracting the carbon that is
22 also included in the reported CH₄ emissions, per the discussion in the Petrochemical Production QA/QC and
23 Verification section, above. As of this current report, timing and resources have not allowed EPA to complete this
24 analysis of activity data, emissions, and emission factors and remains a priority improvement within the IPPU
25 chapter.

26 Pending resources, a secondary potential improvement for this source category would focus on continuing to
27 analyze the fuel and feedstock data from EPA's GHGRP to better disaggregate energy-related emissions and
28 allocate them more accurately between the Energy and IPPU sectors of the Inventory. Some degree of double
29 counting may occur between CO₂ estimates of non-energy use of fuels in the energy sector and CO₂ process
30 emissions from petrochemical production in this sector. This is not considered to be a significant issue since the
31 non-energy use industrial release data includes different categories of sources than those included in this sector.
32 As noted previously in the methodology section, data integration is not feasible at this time as feedstock data from
33 the EIA used to estimate non-energy uses of fuels are aggregated by fuel type, rather than disaggregated by both
34 fuel type and particular industries. As described in the methodology section of this source category, EPA is
35 currently unable to use GHGRP-reported data on quantities of fuel consumed as feedstocks by petrochemical
36 producers, only feedstock type, due to the data failing GHGRP CBI aggregation criteria. Incorporating this data into
37 future Inventories will allow for easier data integration between the non-energy uses of fuels category and the
38 petrochemicals category presented in this chapter. This planned improvement is still under development and has
39 not been completed to report on progress in this current Inventory.

4.14 HCFC-22 Production (CRF Source Category 2B9a)

Trifluoromethane (HFC-23 or CHF₃) is generated as a byproduct during the manufacture of chlorodifluoromethane (HCFC-22), which is primarily employed in refrigeration and air conditioning systems and as a chemical feedstock for manufacturing synthetic polymers. Between 1990 and 2000, U.S. production of HCFC-22 increased significantly as HCFC-22 replaced chlorofluorocarbons (CFCs) in many applications. Between 2000 and 2007, U.S. production fluctuated but generally remained above 1990 levels. In 2008 and 2009, U.S. production declined markedly and has remained near 2009 levels since. Because HCFC-22 depletes stratospheric ozone, its production for non-feedstock uses is scheduled to be phased out by 2020 under the U.S. Clean Air Act.⁵³ Feedstock production, however, is permitted to continue indefinitely.

HCFC-22 is produced by the reaction of chloroform (CHCl₃) and hydrogen fluoride (HF) in the presence of a catalyst, SbCl₅. The reaction of the catalyst and HF produces SbCl_xF_y, (where x + y = 5), which reacts with chlorinated hydrocarbons to replace chlorine atoms with fluorine. The HF and chloroform are introduced by submerged piping into a continuous-flow reactor that contains the catalyst in a hydrocarbon mixture of chloroform and partially fluorinated intermediates. The vapors leaving the reactor contain HCFC-21 (CHCl₂F), HCFC-22 (CHClF₂), HFC-23 (CHF₃), HCl, chloroform, and HF. The under-fluorinated intermediates (HCFC-21) and chloroform are then condensed and returned to the reactor, along with residual catalyst, to undergo further fluorination. The final vapors leaving the condenser are primarily HCFC-22, HFC-23, HCl and residual HF. The HCl is recovered as a useful byproduct, and the HF is removed. Once separated from HCFC-22, the HFC-23 may be released to the atmosphere, recaptured for use in a limited number of applications, or destroyed.

Two facilities produced HCFC-22 in the United States in 2019. Emissions of HFC-23 from this activity in 2019 were estimated to be 3.7 MMT CO₂ Eq. (0.3 kt) (see Table 4-50). This quantity represents a 13 percent increase from 2018 emissions and a 92 percent decrease from 1990 emissions. The decrease from 1990 emissions was caused primarily by changes in the HFC-23 emission rate (kg HFC-23 emitted/kg HCFC-22 produced). The increase from 2018 emissions was caused primarily by an increase in the HFC-23 emission rate at one plant. The long-term decrease in the emission rate is primarily attributable to six factors: (a) five plants that did not capture and destroy the HFC-23 generated have ceased production of HCFC-22 since 1990; (b) one plant that captures and destroys the HFC-23 generated began to produce HCFC-22; (c) one plant implemented and documented a process change that reduced the amount of HFC-23 generated; (d) the same plant began recovering HFC-23, primarily for destruction and secondarily for sale; (e) another plant began destroying HFC-23; and (f) the same plant, whose emission rate was higher than that of the other two plants, ceased production of HCFC-22 in 2013.

⁵³ As construed, interpreted, and applied in the terms and conditions of the Montreal Protocol on Substances that Deplete the Ozone Layer [42 U.S.C. §7671m(b), CAA §614].

1 **Table 4-50: HFC-23 Emissions from HCFC-22 Production (MMT CO₂ Eq. and kt HFC-23)**

Year	MMT CO ₂ Eq.	kt HFC-23
1990	46.1	3
2005	20.0	1
2015	4.3	0.3
2016	2.8	0.2
2017	5.2	0.3
2018	3.3	0.2
2019	3.7	0.3

2 **Methodology**

3 To estimate HFC-23 emissions for five of the eight HCFC-22 plants that have operated in the United States since
 4 1990, methods comparable to the Tier 3 methods in the *2006 IPCC Guidelines* (IPCC 2006) were used. Emissions for
 5 2010 through 2019 were obtained through reports submitted by U.S. HCFC-22 production facilities to EPA’s
 6 Greenhouse Gas Reporting Program (GHGRP). EPA’s GHGRP mandates that all HCFC-22 production facilities report
 7 their annual emissions of HFC-23 from HCFC-22 production processes and HFC-23 destruction processes.
 8 Previously, data were obtained by EPA through collaboration with an industry association that received voluntarily
 9 reported HCFC-22 production and HFC-23 emissions annually from all U.S. HCFC-22 producers from 1990 through
 10 2009. These emissions were aggregated and reported to EPA on an annual basis.

11 For the other three plants, the last of which closed in 1993, methods comparable to the Tier 1 method in the *2006*
 12 *IPCC Guidelines* were used. Emissions from these three plants have been calculated using the recommended
 13 emission factor for unoptimized plants operating before 1995 (0.04 kg HCFC-23/kg HCFC-22 produced).

14 The five plants that have operated since 1994 measure (or, for the plants that have since closed, measured)
 15 concentrations of HFC-23 as well as mass flow rates of process streams to estimate their generation of HFC-23.
 16 Plants using thermal oxidation to abate their HFC-23 emissions monitor the performance of their oxidizers to verify
 17 that the HFC-23 is almost completely destroyed. One plant that releases a small fraction of its byproduct HFC-23
 18 periodically measures HFC-23 concentrations at process vents using gas chromatography. This information is
 19 combined with information on quantities of products (e.g., HCFC-22) to estimate HFC-23 emissions.

20 To estimate 1990 through 2009 emissions, reports from an industry association were used that aggregated HCFC-
 21 22 production and HFC-23 emissions from all U.S. HCFC-22 producers and reported them to EPA (ARAP 1997, 1999,
 22 2000, 2001, 2002, 2003, 2004, 2005, 2006, 2007, 2008, 2009, and 2010). To estimate 2010 through 2019
 23 emissions, facility-level data (including both HCFC-22 production and HFC-23 emissions) reported through EPA’s
 24 GHGRP were analyzed. In 1997 and 2008, comprehensive reviews of plant-level estimates of HFC-23 emissions and
 25 HCFC-22 production were performed (RTI 1997; RTI 2008). The 1997 and 2008 reviews enabled U.S. totals to be
 26 reviewed, updated, and where necessary, corrected, and also for plant-level uncertainty analyses (Monte-Carlo
 27 simulations) to be performed for 1990, 1995, 2000, 2005, and 2006. Estimates of annual U.S. HCFC-22 production
 28 are presented in Table 4-51.

1 **Table 4-51: HCFC-22 Production (kt)**

Year	kt
1990	139
2005	156
2012	96
2013-2019	C

C (CBI)

Note: HCFC-22 production in 2013 through 2019 is considered Confidential Business Information (CBI) as there were only two producers of HCFC-22 in those years.

2 Uncertainty and Time-Series Consistency

3 The uncertainty analysis presented in this section was based on a plant-level Monte Carlo Stochastic Simulation for
 4 2006. The Monte Carlo analysis used estimates of the uncertainties in the individual variables in each plant’s
 5 estimating procedure. This analysis was based on the generation of 10,000 random samples of model inputs from
 6 the probability density functions for each input. A normal probability density function was assumed for all
 7 measurements and biases except the equipment leak estimates for one plant; a log-normal probability density
 8 function was used for this plant’s equipment leak estimates. The simulation for 2006 yielded a 95-percent
 9 confidence interval for U.S. emissions of 6.8 percent below to 9.6 percent above the reported total.

10 The relative errors yielded by the Monte Carlo Stochastic Simulation for 2006 were applied to the U.S. emission
 11 estimate for 2019. The resulting estimates of absolute uncertainty are likely to be reasonably accurate because (1)
 12 the methods used by the two remaining plants to estimate their emissions are not believed to have changed
 13 significantly since 2006, and (2) although the distribution of emissions among the plants has changed between
 14 2006 and 2019 (because one plant has closed), the plant that currently accounts for most emissions had a relative
 15 uncertainty in its 2006 (as well as 2005) emissions estimate that was similar to the relative uncertainty for total
 16 U.S. emissions. Thus, the closure of one plant is not likely to have a large impact on the uncertainty of the national
 17 emission estimate.

18 The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-52. HFC-23 emissions
 19 from HCFC-22 production were estimated to be between 3.5 and 4.1 MMT CO₂ Eq. at the 95 percent confidence
 20 level. This indicates a range of approximately 7 percent below and 10 percent above the emission estimate of 3.7
 21 MMT CO₂ Eq.

22 **Table 4-52: Approach 2 Quantitative Uncertainty Estimates for HFC-23 Emissions from**
 23 **HCFC-22 Production (MMT CO₂ Eq. and Percent)**

Source	Gas	2019 Emission Estimate (MMT CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a (MMT CO ₂ Eq.)			
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
HCFC-22 Production	HFC-23	3.7	3.5	4.1	-7%	+10%

^a Range of emissions reflects a 95 percent confidence interval.

24 Methodological approaches were applied to the entire time series to ensure consistency in emissions estimates
 25 from 1990 through 2019. See Methods discussion of this section above.

QA/QC and Verification

General quality assurance/quality control (QA/QC) procedures were applied consistent with the U.S. Inventory QA/QC plan, which is in accordance with Volume 1, Chapter 6 of *2006 IPCC Guidelines* as described in the introduction of the IPPU chapter (see Annex 8 for more details). Under the GHGRP, EPA verifies annual facility-level reports through a multi-step process (e.g., including a combination of pre-and post-submittal electronic checks and manual reviews by staff) to identify potential errors and ensure that data submitted to EPA are accurate, complete, and consistent (EPA 2015).⁵⁴ Based on the results of the verification process, EPA follows up with facilities to resolve mistakes that may have occurred. The post-submittals checks are consistent with a number of general and category-specific QC procedures, including: range checks, statistical checks, algorithm checks, and year-to-year checks of reported data and emissions.

The GHGRP also requires source-specific quality control measures for the HCFC-22 Production category. Under EPA's GHGRP, HCFC-22 producers are required to (1) measure concentrations of HFC-23 and HCFC-22 in the product stream at least weekly using equipment and methods (e.g., gas chromatography) with an accuracy and precision of 5 percent or better at the concentrations of the process samples, (2) measure mass flows of HFC-23 and HCFC-22 at least weekly using measurement devices (e.g., flowmeters) with an accuracy and precision of 1 percent of full scale or better, (3) calibrate mass measurement devices at the frequency recommended by the manufacturer using traceable standards and suitable methods published by a consensus standards organization, (4) calibrate gas chromatographs at least monthly through analysis of certified standards, and (5) document these calibrations.

4.15 Carbon Dioxide Consumption (CRF Source Category 2B10)

Carbon dioxide (CO₂) is used for a variety of commercial applications, including food processing, chemical production, carbonated beverage production, and refrigeration, and is also used in petroleum production for enhanced oil recovery (EOR). CO₂ used for EOR is injected underground to enable additional petroleum to be produced. For the purposes of this analysis, CO₂ used in commercial applications other than EOR is assumed to be emitted to the atmosphere. A further discussion of CO₂ used in EOR is described in the Energy chapter in Box 3-6 titled "Carbon Dioxide Transport, Injection, and Geological Storage" and is not included in this section.

Carbon dioxide is produced from naturally-occurring CO₂ reservoirs, as a byproduct from the energy and industrial production processes (e.g., ammonia production, fossil fuel combustion, ethanol production), and as a byproduct from the production of crude oil and natural gas, which contain naturally occurring CO₂ as a component.

In 2019, the amount of CO₂ produced and captured for commercial applications and subsequently emitted to the atmosphere was 4.9 MMT CO₂ Eq. (4,870 kt) (see Table 4-53). This is an 18 percent increase (740 kt) from 2018 levels and is an increase of approximately 231 percent since 1990.

Table 4-53: CO₂ Emissions from CO₂ Consumption (MMT CO₂ Eq. and kt)

Year	MMT CO ₂ Eq.	kt
1990	1.5	1,472
2005	1.4	1,375

⁵⁴ EPA (2015). Greenhouse Gas Reporting Program Report Verification. Available online at <https://www.epa.gov/sites/production/files/2015-07/documents/ghgrp_verification_factsheet.pdf>.

Year	MMT CO ₂ Eq.	kt
2015	4.9	4,940
2016	4.6	4,640
2017	4.6	4,580
2018	4.1	4,130
2019	4.9	4,870

1 Methodology

2 Carbon dioxide emission estimates for 1990 through 2019 were based on the quantity of CO₂ extracted and
3 transferred for industrial applications (i.e., non-EOR end-uses). Some of the CO₂ produced by these facilities is used
4 for EOR, and some is used in other commercial applications (e.g., chemical manufacturing, food production). It is
5 assumed that 100 percent of the CO₂ production used in commercial applications other than EOR is eventually
6 released into the atmosphere.

7 2010 through 2019

8 For 2010 through 2019, data from EPA's GHGRP (Subpart PP) were aggregated from facility-level reports to
9 develop a national-level estimate for use in the Inventory (EPA 2020). Facilities report CO₂ extracted or produced
10 from natural reservoirs and industrial sites, and CO₂ captured from energy and industrial processes and transferred
11 to various end-use applications to EPA's GHGRP. This analysis includes only reported CO₂ transferred to food and
12 beverage end-uses. EPA is continuing to analyze and assess integration of CO₂ transferred to other end-uses to
13 enhance the completeness of estimates under this source category. Other end-uses include industrial applications,
14 such as metal fabrication. EPA is analyzing the information reported to ensure that other end-use data excludes
15 non-emissive applications and publication will not reveal CBI. Reporters subject to EPA's GHGRP Subpart PP are
16 also required to report the quantity of CO₂ that is imported and/or exported. Currently, these data are not publicly
17 available through the GHGRP due to data confidentiality reasons and hence are excluded from this analysis.

18 Facilities subject to Subpart PP of EPA's GHGRP are required to measure CO₂ extracted or produced. More details
19 on the calculation and monitoring methods applicable to extraction and production facilities can be found under
20 Subpart PP: Suppliers of Carbon Dioxide of the regulation, Part 98.⁵⁵ The number of facilities that reported data to
21 EPA's GHGRP Subpart PP (Suppliers of Carbon Dioxide) for 2010 through 2019 is much higher (ranging from 44 to
22 53) than the number of facilities included in the Inventory for the 1990 to 2009 time period prior to the availability
23 of GHGRP data (4 facilities). The difference is largely due to the fact the 1990 to 2009 data includes only CO₂
24 transferred to end-use applications from naturally occurring CO₂ reservoirs and excludes industrial sites.

25 1990 through 2009

26 For 1990 through 2009, data from EPA's GHGRP are not available. For this time period, CO₂ production data from
27 four naturally-occurring CO₂ reservoirs were used to estimate annual CO₂ emissions. These facilities were Jackson
28 Dome in Mississippi, Bravo and West Bravo Domes in New Mexico, and McCallum Dome in Colorado. The facilities
29 in Mississippi and New Mexico produced CO₂ for use in both EOR and in other commercial applications (e.g.,
30 chemical manufacturing, food production). The fourth facility in Colorado (McCallum Dome) produced CO₂ for
31 commercial applications only (New Mexico Bureau of Geology and Mineral Resources 2006).

32 Carbon dioxide production data and the percentage of production that was used for non-EOR applications for the
33 Jackson Dome, Mississippi facility were obtained from Advanced Resources International (ARI 2006, 2007) for 1990
34 to 2000, and from the Annual Reports of Denbury Resources (Denbury Resources 2002 through 2010) for 2001 to

⁵⁵ See <http://www.ecfr.gov/cgi-bin/text-idx?tpl=/ecfrbrowse/Title40/40cfr98_main_02.tpl>.

1 2009 (see Table 4-54). Denbury Resources reported the average CO₂ production in units of MMCF CO₂ per day for
 2 2001 through 2009 and reported the percentage of the total average annual production that was used for EOR.
 3 Production from 1990 to 1999 was set equal to 2000 production, due to lack of publicly available production data
 4 for 1990 through 1999. Carbon dioxide production data for the Bravo Dome and West Bravo Dome were obtained
 5 from ARI for 1990 through 2009 (ARI 1990 to 2010). Data for the West Bravo Dome facility were only available for
 6 2009. The percentage of total production that was used for non-EOR applications for the Bravo Dome and West
 7 Bravo Dome facilities for 1990 through 2009 were obtained from New Mexico Bureau of Geology and Mineral
 8 Resources (Broadhead 2003; New Mexico Bureau of Geology and Mineral Resources 2006). Production data for the
 9 McCallum Dome (Jackson County), Colorado facility were obtained from the Colorado Oil and Gas Conservation
 10 Commission (COGCC) for 1999 through 2009 (COGCC 2014). Production data for 1990 to 1998 and percentage of
 11 production used for EOR were assumed to be the same as for 1999, due to lack of publicly available data.

12 **Table 4-54: CO₂ Production (kt CO₂) and the Percent Used for Non-EOR Applications**

Year	Jackson Dome, MS CO ₂ Production (kt) (% Non-EOR)	Bravo Dome, NM CO ₂ Production (kt) (% Non-EOR)	West Bravo Dome, NM CO ₂ Production (kt) (% Non-EOR)	McCallum Dome, CO CO ₂ Production (kt) (% Non- EOR)	Total CO ₂ Production from Extraction and Capture Facilities (kt)	% Non- EOR ^a
1990	1,344 (100%)	63 (1%)	+	65 (100%)	NA	NA
2005	1,254 (27%)	58 (1%)	+	63 (100%)	NA	NA
2015	NA	NA	NA	NA	64,800 ^b	8%
2016	NA	NA	NA	NA	55,900 ^b	8%
2017	NA	NA	NA	NA	59,900 ^b	8%
2018	NA	NA	NA	NA	58,400 ^b	7%
2019	NA	NA	NA	NA	61,300 ^b	8%

+ Does not exceed 0.5 percent.

NA (Not Available)

^a Includes only food & beverage applications.

^b For 2010 through 2019, the publicly available GHGRP data were aggregated at the national level based on GHGRP CBI criteria.

13 **Uncertainty and Time-Series Consistency – TO BE UPDATED**

14 There is uncertainty associated with the data reported through EPA’s GHGRP. Specifically, there is uncertainty
 15 associated with the amount of CO₂ consumed for food and beverage applications, given the GHGRP does have
 16 provisions that Subpart PP reporters are not required to report to the GHGRP if their emissions fall below certain
 17 thresholds, in addition to the exclusion of the amount of CO₂ transferred to all other end-use categories. This latter
 18 category might include CO₂ quantities that are being used for non-EOR industrial applications such as firefighting.
 19 Second, uncertainty is associated with the exclusion of imports/exports data for CO₂ suppliers. Currently these
 20 data are not publicly available through EPA’s GHGRP and hence are excluded from this analysis. EPA verifies annual
 21 facility-level reports through a multi-step process (e.g., combination of electronic checks and manual reviews by
 22 staff) to identify potential errors and ensure that data submitted to EPA are accurate, complete, and consistent.
 23 Based on the results of the verification process, EPA follows up with facilities to resolve mistakes that may have
 24 occurred.⁵⁶

25 The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-55. Carbon dioxide
 26 consumption CO₂ emissions for 2018 were estimated to be between 4.2 and 4.7 MMT CO₂ Eq. at the 95 percent

⁵⁶ See <https://www.epa.gov/sites/production/files/2015-07/documents/ghgrp_verification_factsheet.pdf>.

confidence level. This indicates a range of approximately 5 percent below to 5 percent above the emission estimate of 4.5 MMT CO₂ Eq.

Table 4-55: Approach 2 Quantitative Uncertainty Estimates for CO₂ Emissions from CO₂ Consumption (MMT CO₂ Eq. and Percent)

Source	Gas	2018 Emission Estimate (MMT CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			(MMT CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
CO ₂ Consumption	CO ₂	4.5	4.2	4.7	-5%	+5%

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

Methodological approaches were applied to the entire time series to ensure consistency in emissions from 1990 through 2018.

QA/QC and Verification

General quality assurance/quality control (QA/QC) procedures were applied consistent with the U.S. Inventory QA/QC plan, which is in accordance with Volume 1, Chapter 6 of *2006 IPCC Guidelines* as described in the introduction of the IPPU chapter (see Annex 8 for more details). More details on the greenhouse gas calculation, monitoring and QA/QC methods applicable to CO₂ Consumption can be found under Subpart PP (Suppliers of Carbon Dioxide) of the regulation (40 CFR Part 98).⁵⁷ EPA verifies annual facility-level GHGRP reports through a multi-step process (e.g., combination of electronic checks and manual reviews) to identify potential errors and ensure that data submitted to EPA are accurate, complete, and consistent (EPA 2015).⁵⁸ Based on the results of the verification process, EPA follows up with facilities to resolve mistakes that may have occurred. The post-submittals checks are consistent with a number of general and category-specific QC procedures, including range checks, statistical checks, algorithm checks, and year-to-year checks of reported data and emissions.

Recalculations Discussion

For the current Inventory, updated GHGRP Subpart PP data were available for the 2015 through 2018 portion of the time series, resulting in recalculations for each of these years. Data from EPA's GHGRP (Subpart PP) were previously unavailable for use for the years 2015 through 2018, so the emissions estimates for 2015 through 2018 had been held constant from 2014. Compared to the previous Inventory, emissions increased by 10 percent for 2015 (470 kt CO₂ Eq.), increased by 4 percent for 2016 (170 kt CO₂ Eq.), increased by 2 percent for 2017 (110 kt CO₂ Eq.) and decreased by 8 percent for 2018 (340 kt CO₂ Eq.).

Planned Improvements

EPA will continue to evaluate the potential to include additional GHGRP data on other emissive end-uses to improve the accuracy and completeness of estimates for this source category. Particular attention will be made to ensuring time-series consistency of the emissions estimates presented in future Inventory reports, consistent with IPCC and UNFCCC guidelines. This is required as the facility-level reporting data from EPA's GHGRP, with the program's initial requirements for reporting of emissions in calendar year 2010, are not available for all inventory years (i.e., 1990 through 2009) as required for this Inventory. In implementing improvements and integration of

⁵⁷ See <http://www.ecfr.gov/cgi-bin/text-idx?tpl=/ecfrbrowse/Title40/40cfr98_main_02.tpl>.

⁵⁸ See <https://www.epa.gov/sites/production/files/2015-07/documents/ghgrp_verification_factsheet.pdf>.

1 data from EPA’s GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories
2 will be relied upon.⁵⁹

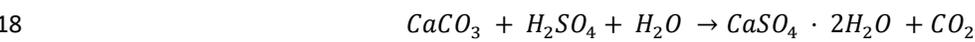
3 These improvements are still in process and will be incorporated into future Inventory reports. These are near- to
4 medium-term improvements.

5 4.16 Phosphoric Acid Production (CRF Source 6 Category 2B10)

7 Phosphoric acid (H₃PO₄) is a basic raw material used in the production of phosphate-based fertilizers. Phosphoric
8 acid production from natural phosphate rock is a source of carbon dioxide (CO₂) emissions, due to the chemical
9 reaction of the inorganic carbon (calcium carbonate) component of the phosphate rock.

10 Phosphate rock is mined in Florida and North Carolina, which account for more than 75 percent of total domestic
11 output, and in Idaho and Utah (USGS 2020). It is used primarily as a raw material for wet-process phosphoric acid
12 production. The composition of natural phosphate rock varies, depending on the location where it is mined.
13 Natural phosphate rock mined in the United States generally contains inorganic carbon in the form of calcium
14 carbonate (limestone) and may also contain organic carbon.

15 The phosphoric acid production process involves chemical reaction of the calcium phosphate (Ca₃(PO₄)₂)
16 component of the phosphate rock with sulfuric acid (H₂SO₄) and recirculated phosphoric acid (H₃PO₄) (EFMA 2000).
17 The generation of CO₂, however, is due to the associated limestone-sulfuric acid reaction, as shown below:



19 Total U.S. phosphate rock production used in 2019 was an estimated 23.0 million metric tons (USGS 2020). Total
20 imports of phosphate rock to the United States in 2019 were estimated to be approximately 2.0 million metric tons
21 (USGS 2020). Between 2015 and 2018, most of the imported phosphate rock (79 percent) came from Peru, with 20
22 percent from Morocco and 1 percent from other sources (USGS 2020). All phosphate rock mining companies in the
23 U.S. are vertically integrated with fertilizer plants that produce phosphoric acid located near the mines. The
24 phosphoric acid production facilities that use imported phosphate rock are located in Louisiana.

25 Over the 1990 to 2019 period, domestic phosphoric acid production has decreased by nearly 54 percent. Total CO₂
26 emissions from phosphoric acid production were 0.9 MMT CO₂ Eq. (891 kt CO₂) in 2019 (see Table 4-56). Domestic
27 consumption of phosphate rock in 2019 was estimated to have decreased 4 percent relative to 2018 levels (USGS
28 2020).

29 **Table 4-56: CO₂ Emissions from Phosphoric Acid Production (MMT CO₂ Eq. and kt)**

Year	MMT CO ₂ Eq.	kt
1990	1.5	1,529
2005	1.3	1,342
2015	1.0	999
2016	1.0	998
2017	1.0	1,028
2018	0.9	940
2019	0.9	891

⁵⁹ See <http://www.ipcc-nggip.iges.or.jp/public/tb/TFI_Technical_Bulletin_1.pdf>.

1 Methodology

2 Carbon dioxide emissions from production of phosphoric acid from phosphate rock are estimated by multiplying
3 the average amount of inorganic carbon (expressed as CO₂) contained in the natural phosphate rock as calcium
4 carbonate by the amount of phosphate rock that is used annually to produce phosphoric acid, accounting for
5 domestic production and net imports for consumption. The estimation methodology is as follows:

$$6 \quad E_{pa} = C_{pr} \times Q_{pr}$$

7 where,

E_{pa}	=	CO ₂ emissions from phosphoric acid production, metric tons
C_{pr}	=	Average amount of carbon (expressed as CO ₂) in natural phosphate rock, metric ton CO ₂ / metric ton phosphate rock
Q_{pr}	=	Quantity of phosphate rock used to produce phosphoric acid

8
9 The CO₂ emissions calculation methodology assumes that all of the inorganic C (calcium carbonate) content of the
10 phosphate rock reacts to produce CO₂ in the phosphoric acid production process and is emitted with the stack gas.
11 The methodology also assumes that none of the organic C content of the phosphate rock is converted to CO₂ and
12 that all of the organic C content remains in the phosphoric acid product. The United States uses a country-specific
13 methodology consistent with an IPCC Tier 1 approach to calculate emissions from production of phosphoric acid
14 from phosphate rock.⁶⁰

15 From 1993 to 2004, the U.S. Geological Survey (USGS) *Mineral Yearbook: Phosphate Rock* disaggregated phosphate
16 rock mined annually in Florida and North Carolina from phosphate rock mined annually in Idaho and Utah, and
17 reported the annual amounts of phosphate rock exported and imported for consumption (see Table 4-57). For the
18 years 1990 through 1992, and 2005 through 2019, only nationally aggregated mining data was reported by USGS.
19 For the years 1990, 1991, and 1992, the breakdown of phosphate rock mined in Florida and North Carolina, and
20 the amount mined in Idaho and Utah, are approximated using data reported by USGS for the average share of U.S.
21 production in those states from 1993 to 2004. For the years 2005 through 2019, the same approximation method
22 is used, but data for the share of U.S. production in those states were obtained from the USGS commodity
23 specialist for phosphate rock (USGS 2012). Data for domestic sales or consumption of phosphate rock, exports of
24 phosphate rock (primarily from Florida and North Carolina), and imports of phosphate rock for consumption for
25 1990 through 2010 were obtained from USGS *Minerals Yearbook: Phosphate Rock* (USGS 1994 through 2015b),
26 and from USGS *Minerals Commodity Summaries: Phosphate Rock* (USGS 2016 through 2020). From 2004 through
27 2019, the USGS reported no exports of phosphate rock from U.S. producers (USGS 2020).

28 The carbonate content of phosphate rock varies depending upon where the material is mined. Composition data
29 for domestically mined and imported phosphate rock were provided by the Florida Institute of Phosphate Research
30 (FIPR 2003a). Phosphate rock mined in Florida contains approximately 1 percent inorganic C, and phosphate rock
31 imported from Morocco contains approximately 1.46 percent inorganic C. Calcined phosphate rock mined in North
32 Carolina and Idaho contains approximately 0.41 percent and 0.27 percent inorganic C, respectively (see Table
33 4-58). Similar to the phosphate rock mined in Morocco, phosphate rock mined in Peru contains approximately 5
34 percent CO₂ (Golder Associates and M3 Engineering 2016).

35 Carbonate content data for phosphate rock mined in Florida are used to calculate the CO₂ emissions from
36 consumption of phosphate rock mined in Florida and North Carolina (more than 75 percent of domestic
37 production), and carbonate content data for phosphate rock mined in Morocco and Peru are used to calculate CO₂
38 emissions from consumption of imported phosphate rock. The CO₂ emissions calculation assumes that all of the
39 domestic production of phosphate rock is used in uncalcined form. As of 2006, the USGS noted that one phosphate
40 rock producer in Idaho produces calcined phosphate rock; however, no production data were available for this

⁶⁰ The 2006 IPCC Guidelines do not provide a method for estimating process emissions (CO₂) from Phosphoric Acid Production.

1 single producer (USGS 2006). The USGS confirmed that no significant quantity of domestic production of
 2 phosphate rock is in the calcined form (USGS 2012).

3 **Table 4-57: Phosphate Rock Domestic Consumption, Exports, and Imports (kt)**

Location/Year	1990	2005	2015	2016	2017	2018	2019
U.S. Domestic Consumption	49,800	35,200	26,200	26,700	26,300	23,300	23,000
FL and NC	42,494	28,160	20,960	21,360	21,040	18,640	18,400
ID and UT	7,306	7,040	5,240	5,340	5,260	4,660	4,600
Exports—FL and NC	6,240	0	0	0	0	0	0
Imports	451	2,630	1,960	1,590	2,470	2,770	2,000
Total U.S. Consumption	44,011	37,830	28,160	28,290	28,770	26,070	25,000

4 **Table 4-58: Chemical Composition of Phosphate Rock (Percent by Weight)**

Composition	Central Florida	North Florida	North Carolina (calcined)	Idaho (calcined)	Morocco
Total Carbon (as C)	1.60	1.76	0.76	0.60	1.56
Inorganic Carbon (as C)	1.00	0.93	0.41	0.27	1.46
Organic Carbon (as C)	0.60	0.83	0.35	0.00	0.10
Inorganic Carbon (as CO ₂)	3.67	3.43	1.50	1.00	5.00

Source: FIPR (2003a).

5 **Uncertainty and Time-Series Consistency – TO BE UPDATED** 6 **FOR FINAL REPORT**

7 Phosphate rock production data used in the emission calculations were developed by the USGS through monthly
 8 and semiannual voluntary surveys of the active phosphate rock mines during 2019. Prior to 2006, USGS provided
 9 the data disaggregated regionally; however, beginning in 2006, only total U.S. phosphate rock production was
 10 reported. Regional production for 2019 was estimated based on regional production data from 2005 to 2011 and
 11 multiplied by regionally-specific emission factors. There is uncertainty associated with the degree to which the
 12 estimated 2019 regional production data represents actual production in those regions. Total U.S. phosphate rock
 13 production data are not considered to be a significant source of uncertainty because all the domestic phosphate
 14 rock producers report their annual production to the USGS. Data for exports of phosphate rock used in the
 15 emission calculations are reported to the USGS by phosphate rock producers and are not considered to be a
 16 significant source of uncertainty. Data for imports for consumption are based on international trade data collected
 17 by the U.S. Census Bureau. These U.S. government economic data are not considered to be a significant source of
 18 uncertainty.

19 An additional source of uncertainty in the calculation of CO₂ emissions from phosphoric acid production is the
 20 carbonate composition of phosphate rock, as the composition of phosphate rock varies depending upon where the
 21 material is mined and may also vary over time. The Inventory relies on one study (FIPR 2003a) of chemical
 22 composition of the phosphate rock; limited data are available beyond this study. Another source of uncertainty is
 23 the disposition of the organic carbon content of the phosphate rock. A representative of FIPR indicated that in the
 24 phosphoric acid production process the organic C content of the mined phosphate rock generally remains in the
 25 phosphoric acid product, which is what produces the color of the phosphoric acid product (FIPR 2003b). Organic
 26 carbon is therefore not included in the calculation of CO₂ emissions from phosphoric acid production.

27 A third source of uncertainty is the assumption that all domestically-produced phosphate rock is used in
 28 phosphoric acid production and used without first being calcined. Calcination of the phosphate rock would result
 29 in conversion of some of the organic C in the phosphate rock into CO₂. However, according to air permit
 30 information available to the public, at least one facility has calcining units permitted for operation (NCDENR 2013).

31 Finally, USGS indicated that in 2017 less than 5 percent of domestically-produced phosphate rock was used to
 32 manufacture elemental phosphorus and other phosphorus-based chemicals, rather than phosphoric acid (USGS

2019b). According to USGS, there is only one domestic producer of elemental phosphorus, in Idaho, and no data were available concerning the annual production of this single producer. Elemental phosphorus is produced by reducing phosphate rock with coal coke, and it is therefore assumed that 100 percent of the carbonate content of the phosphate rock will be converted to CO₂ in the elemental phosphorus production process. The calculation for CO₂ emissions assumes that phosphate rock consumption, for purposes other than phosphoric acid production, results in CO₂ emissions from 100 percent of the inorganic carbon content in phosphate rock, but none from the organic carbon content.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-59. 2019 phosphoric acid production CO₂ emissions were estimated to be between 0.8 and 1.2 MMT CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 18 percent below and 20 percent above the emission estimate of 0.9 MMT CO₂ Eq.

Table 4-59: Approach 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Phosphoric Acid Production (MMT CO₂ Eq. and Percent)

Source	Gas	2019 Emission Estimate (MMT CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a (MMT CO ₂ Eq.)			
			Lower Bound	Upper Bound	Lower Bound (%)	Upper Bound (%)
Phosphoric Acid Production	CO ₂	0.9	0.8	1.2	-18%	+20%

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

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

QA/QC and Verification

For more information on the general QA/QC process applied to this source category, consistent with the U.S. Inventory QA/QC plan, which is in accordance with Volume 1, Chapter 6 of *2006 IPCC Guidelines* as described in the introduction of the IPPU chapter (see Annex 8 for more details).

Recalculations Discussion

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

Planned Improvements

EPA continues to evaluate potential improvements to the Inventory estimates for this source category, which include direct integration of EPA's GHGRP data for 2010 through 2019 along with assessing applicability of reported GHGRP data to update the inorganic C content of phosphate rock for prior years to ensure time series consistency. Specifically, EPA would need to assess that averaged inorganic C content data (by region or other approaches) meets GHGRP confidential business information (CBI) screening criteria. EPA would then need to assess the applicability of GHGRP data for the averaged inorganic C content (by region or other approaches) from 2010 through 2019, along with other information to inform estimates in prior years in the required time series (1990 through 2009) based on the sources of phosphate rock used in production of phosphoric acid over time. In implementing improvements and integration of data from EPA's GHGRP, the latest guidance from the IPCC on the

1 use of facility-level data in national inventories will be relied upon.⁶¹ These long-term planned improvements are
2 still in development by EPA and have not been implemented into the current Inventory report.

3 4.17 Iron and Steel Production (CRF Source 4 Category 2C1) and Metallurgical Coke 5 Production

6 Iron and steel production is a multi-step process that generates process-related emissions of carbon dioxide (CO₂)
7 and methane (CH₄) as raw materials are refined into iron and then transformed into crude steel. Emissions from
8 conventional fuels (e.g., natural gas, fuel oil) consumed for energy purposes during the production of iron and steel
9 are accounted for in the Energy chapter.

10 Iron and steel production includes six distinct production processes: coke production, sinter production, direct
11 reduced iron (DRI) production, pig iron⁶² production, electric arc furnace (EAF) steel production, and basic oxygen
12 furnace (BOF) steel production. The number of production processes at a particular plant is dependent upon the
13 specific plant configuration. Most process CO₂ generated from the iron and steel industry is a result of the
14 production of crude iron.

15 In addition to the production processes mentioned above, CO₂ is also generated at iron and steel mills through the
16 consumption of process byproducts (e.g., blast furnace gas, coke oven gas) used for various purposes including
17 heating, annealing, and electricity generation. Process byproducts sold for use as synthetic natural gas are also
18 included in these calculations. In general, CO₂ emissions are generated in these production processes through the
19 reduction and consumption of various carbon-containing inputs (e.g., ore, scrap, flux, coke byproducts). Fugitive
20 CH₄ emissions can also be generated from these processes, as well as from sinter, direct iron and pellet
21 production.

22 Currently, there are approximately nine integrated iron and steel steelmaking facilities that utilize BOFs to refine
23 and produce steel from iron. As of 2018, these facilities have 21 active blast furnaces between them. Almost 100
24 steelmaking facilities utilize EAFs to produce steel primarily from recycled ferrous scrap (USGS 2019). The trend in
25 the United States for integrated facilities has been a shift towards fewer BOFs and more EAFs. EAFs use scrap steel
26 as their main input and use significantly less energy than BOFs. There are also 14 cokemaking facilities, of which 3
27 facilities are co-located with integrated iron and steel facilities (ACCCI 2020). In the United States, four states
28 account for roughly 51 percent of total raw steel production: Indiana, Ohio, Michigan, and Pennsylvania (USGS
29 2019).

30 Total annual production of crude steel in the United States was fairly constant between 2000 and 2008 and ranged
31 from a low of 99,320,000 tons to a high of 109,880,000 tons (2001 and 2004, respectively). Due to the decrease in
32 demand caused by the global economic downturn (particularly from the automotive industry), crude steel
33 production in the United States sharply decreased to 65,459,000 tons in 2009. Crude steel production was fairly
34 constant from 2011 through 2014, and after a dip in production from 2014 to 2015, crude steel production has
35 slowly and steadily increased for the past few years. The United States was the fourth largest producer of raw steel

⁶¹ See <http://www.ipcc-nggip.iges.or.jp/public/tb/TFI_Technical_Bulletin_1.pdf>.

⁶² Pig iron is the common industry term to describe what should technically be called crude iron. Pig iron is a subset of crude iron that has lost popularity over time as industry trends have shifted. Throughout this report, pig iron will be used interchangeably with crude iron, but it should be noted that in other data sets or reports pig iron and crude iron may not be used interchangeably and may provide different values.

1 in the world, behind China, India and Japan, accounting for approximately 4.6 percent of world production in 2019
2 (AISI 2004 through 2020).

3 The majority of CO₂ emissions from the iron and steel production process come from the use of metallurgical coke
4 in the production of pig iron and from the consumption of other process byproducts, with lesser amounts emitted
5 from the use of flux and from the removal of carbon from pig iron used to produce steel.

6 According to the *2006 IPCC Guidelines*, the production of metallurgical coke from coking coal is considered to be an
7 energy use of fossil fuel, and the use of coke in iron and steel production is considered to be an industrial process
8 source. Therefore, the *2006 IPCC Guidelines* suggest that emissions from the production of metallurgical coke
9 should be reported separately in the Energy sector, while emissions from coke consumption in iron and steel
10 production should be reported in the Industrial Processes and Product Use sector. The approaches and emission
11 estimates for both metallurgical coke production and iron and steel production, however, are presented here
12 because much of the relevant activity data is used to estimate emissions from both metallurgical coke production
13 and iron and steel production. For example, some byproducts (e.g., coke oven gas) of the metallurgical coke
14 production process are consumed during iron and steel production, and some byproducts of the iron and steel
15 production process (e.g., blast furnace gas) are consumed during metallurgical coke production. Emissions
16 associated with the consumption of these byproducts are attributed at the point of consumption. Emissions
17 associated with the use of conventional fuels (e.g., natural gas, fuel oil) for electricity generation, heating and
18 annealing, or other miscellaneous purposes downstream of the iron and steelmaking furnaces are reported in the
19 Energy chapter.

20 Metallurgical Coke Production

21 Emissions of CO₂ from metallurgical coke production in 2019 were 1.4 MMT CO₂ Eq. (1,366 kt CO₂) (see Table 4-60
22 and Table 4-61). Emissions increased slightly in 2019 by 7 percent from 2018 levels and have decreased by 76
23 percent (4.2 MMT CO₂ Eq.) since 1990. Coke production in 2019 was about 2 percent lower than in 2018 and 51
24 percent below 1990.

25 **Table 4-60: CO₂ Emissions from Metallurgical Coke Production (MMT CO₂ Eq.)**

Gas	1990	2005	2015	2016	2017	2018	2019
CO ₂	5.6	3.9	4.4	2.6	2.0	1.3	1.4
Total	5.6	3.9	4.4	2.6	2.0	1.3	1.4

26 **Table 4-61: CO₂ Emissions from Metallurgical Coke Production (kt)**

Gas	1990	2005	2015	2016	2017	2018	2019
CO ₂	5,608	3,921	4,417	2,643	1,978	1,282	1,366
Total	5,608	3,921	4,417	2,643	1,978	1,282	1,366

28

29 Iron and Steel Production

30 Emissions of CO₂ and CH₄ from iron and steel production in 2019 were 46.8 MMT CO₂ Eq. (46,753 kt) and 0.0077
31 MMT CO₂ Eq. (0.3 kt CH₄), respectively (see Table 4-62 through Table 4-65), totaling approximately 46.8 MMT CO₂
32 Eq. Emissions slightly decreased in 2019 from 2018 and have decreased overall since 1990 due to restructuring of
33 the industry, technological improvements, and increased scrap steel utilization. Carbon dioxide emission estimates
34 include emissions from the consumption of carbonaceous materials in the blast furnace, EAF, and BOF, as well as
35 blast furnace gas and coke oven gas consumption for other activities at the steel mill.

36 In 2019, domestic production of pig iron decreased by 7 percent from 2018 levels. Overall, domestic pig iron
37 production has declined since the 1990s. Pig iron production in 2019 was 53 percent lower than in 2000 and 55
38 percent below 1990. Carbon dioxide emissions from iron production have decreased by 83 percent since 1990.
39 Carbon dioxide emissions from steel production have decreased by 28 percent (2.2 MMT CO₂ Eq.) since 1990,
40 while overall CO₂ emissions from iron and steel production have declined by 60 percent (71.1 MMT CO₂ Eq.) from
41 1990 to 2019.

1 **Table 4-62: CO₂ Emissions from Iron and Steel Production (MMT CO₂ Eq.)**

Source/Activity Data	1990	2005	2015	2016	2017	2018	2019
Sinter Production	2.4	1.7	1.0	0.9	0.9	0.9	0.9
Iron Production	45.7	17.7	10.3	9.9	8.2	9.6	9.3
Pellet Production	1.8	1.5	1.0	0.9	0.9	0.9	0.9
Steel Production	8.0	9.4	6.9	6.9	6.2	5.8	5.8
Other Activities ^a	41.2	35.9	24.3	22.5	22.4	24.1	23.2
Total	99.1	66.2	43.5	41.0	38.6	41.3	39.9

Note: Totals may not sum due to independent rounding.

^a Includes emissions from blast furnace gas and coke oven gas combustion for activities at the steel mill other than consumption in blast furnace, EAFs, or BOFs.

2 **Table 4-63: CO₂ Emissions from Iron and Steel Production (kt)**

Source/Activity Data	1990	2005	2015	2016	2017	2018	2019
Sinter Production	2,448	1,663	1,016	877	869	937	876
Iron Production	45,704	17,664	10,333	9,930	8,239	9,583	9,275
Pellet Production	1,817	1,503	964	869	867	924	867
Steel Production	7,964	9,395	6,936	6,854	6,218	5,754	5,750
Other Activities ^a	41,193	35,934	24,280	22,451	22,396	24,149	23,158
Total	99,122	66,155	43,525	40,979	38,587	41,345	39,924

Note: Totals may not sum due to independent rounding.

^a Includes emissions from blast furnace gas and coke oven gas combustion for activities at the steel mill other than consumption in blast furnace, EAFs, or BOFs.

3 **Table 4-64: CH₄ Emissions from Iron and Steel Production (MMT CO₂ Eq.)**

Source/Activity Data	1990	2005	2015	2016	2017	2018	2019
Sinter Production	+	+	+	+	+	+	+
Total	+						

+ Does not exceed 0.05 MMT CO₂ Eq.

4 **Table 4-65: CH₄ Emissions from Iron and Steel Production (kt)**

Source/Activity Data	1990	2005	2015	2016	2017	2018	2019
Sinter Production	0.9	0.6	0.3	0.3	0.3	0.3	0.3
Total	0.9	0.6	0.3	0.3	0.3	0.3	0.3

5 Methodology

6 Emission estimates presented in this chapter utilize a country-specific approach based on Tier 2 methodologies
 7 provided by the *2006 IPCC Guidelines*. These Tier 2 methodologies call for a mass balance accounting of the
 8 carbonaceous inputs and outputs during the iron and steel production process and the metallurgical coke
 9 production process. Tier 1 methods are used for certain iron and steel production processes (i.e., sinter
 10 production, pellet production and DRI production) for which available data are insufficient to apply a Tier 2
 11 method.

12 The Tier 2 methodology equation is as follows:

13
$$E_{CO_2} = \left[\sum_a (Q_a \times C_a) - \sum_b (Q_b \times C_b) \right] \times \frac{44}{12}$$

14 where,

15 E_{CO_2} = Emissions from coke, pig iron, EAF steel, or BOF steel production, metric tons
 16 a = Input material a
 17 b = Output material b

1	Q_a	=	Quantity of input material a , metric tons
2	C_a	=	Carbon content of input material a , metric tons C/metric ton material
3	Q_b	=	Quantity of output material b , metric tons
4	C_b	=	Carbon content of output material b , metric tons C/metric ton material
5	44/12	=	Stoichiometric ratio of CO ₂ to C
6			

7 The Tier 1 methodology equations are as follows:

$$8 \quad E_{s,p} = Q_s \times EF_{s,p}$$

$$9 \quad E_{d,CO_2} = Q_d \times EF_{d,CO_2}$$

$$10 \quad E_{p,CO_2} = Q_p \times EF_{p,CO_2}$$

11 where,

12	$E_{s,p}$	=	Emissions from sinter production process for pollutant p (CO ₂ or CH ₄), metric ton
13	Q_s	=	Quantity of sinter produced, metric tons
14	$EF_{s,p}$	=	Emission factor for pollutant p (CO ₂ or CH ₄), metric ton p /metric ton sinter
15	E_{d,CO_2}	=	Emissions from DRI production process for CO ₂ , metric ton
16	Q_d	=	Quantity of DRI produced, metric tons
17	EF_{d,CO_2}	=	Emission factor for CO ₂ , metric ton CO ₂ /metric ton DRI
18	Q_p	=	Quantity of pellets produced, metric tons
19	EF_{p,CO_2}	=	Emission factor for CO ₂ , metric ton CO ₂ /metric ton pellets produced
20			

21 Metallurgical Coke Production

22 Coking coal is used to manufacture metallurgical coke which is used primarily as a reducing agent in the production
 23 of iron and steel, but is also used in the production of other metals including zinc and lead (see Zinc Production and
 24 Lead Production sections of this chapter). Emissions associated with producing metallurgical coke from coking coal
 25 are estimated and reported separately from emissions that result from the iron and steel production process. To
 26 estimate emissions from metallurgical coke production, a Tier 2 method provided by the *2006 IPCC Guidelines* was
 27 utilized. The amount of carbon contained in materials produced during the metallurgical coke production process
 28 (i.e., coke, coke breeze and coke oven gas) is deducted from the amount of carbon contained in materials
 29 consumed during the metallurgical coke production process (i.e., natural gas, blast furnace gas, and coking coal).
 30 Light oil, which is produced during the metallurgical coke production process, is excluded from the deductions due
 31 to data limitations. The amount of carbon contained in these materials is calculated by multiplying the material-
 32 specific carbon content by the amount of material consumed or produced (see Table 4-66). The amount of coal tar
 33 produced was approximated using a production factor of 0.03 tons of coal tar per ton of coking coal consumed.
 34 The amount of coke breeze produced was approximated using a production factor of 0.075 tons of coke breeze per
 35 ton of coking coal consumed (AISI 2008; DOE 2000). Data on the consumption of carbonaceous materials (other
 36 than coking coal) as well as coke oven gas production were available for integrated steel mills only (i.e., steel mills
 37 with co-located coke plants). Therefore, carbonaceous material (other than coking coal) consumption and coke
 38 oven gas production were excluded from emission estimates for merchant coke plants. Carbon contained in coke
 39 oven gas used for coke-oven underfiring was not included in the deductions to avoid double-counting.

1 **Table 4-66: Material Carbon Contents for Metallurgical Coke Production**

Material	kg C/kg
Coal Tar ^a	0.62
Coke ^a	0.83
Coke Breeze ^a	0.83
Coking Coal ^b	0.75
Material	kg C/GJ
Coke Oven Gas ^c	12.1
Blast Furnace Gas ^c	70.8

^a Source: IPCC (2006), Vol. 3 Chapter 4, Table 4.3

^b Source: EIA (2017c)

^c Source: IPCC (2006), Vol. 2 Chapter 1, Table 1.3

2 Although the 2006 IPCC Guidelines provide a Tier 1 CH₄ emission factor for metallurgical coke production (i.e., 0.1 g
 3 CH₄ per metric ton of coke production), it is not appropriate to use because CO₂ emissions were estimated using
 4 the Tier 2 mass balance methodology. The mass balance methodology makes a basic assumption that all carbon
 5 that enters the metallurgical coke production process either exits the process as part of a carbon-containing
 6 output or as CO₂ emissions. This is consistent with a preliminary assessment of aggregated facility-level
 7 greenhouse gas CH₄ emissions reported by coke production facilities under EPA's GHGRP. The assessment indicates
 8 that CH₄ emissions from coke production are insignificant and below 500 kt or 0.05 percent of total national
 9 emissions. Pending resources and significance, EPA continues to assess the possibility of including these emissions
 10 in future Inventories to enhance completeness but has not incorporated these emissions into this report.

11 Data relating to the mass of coking coal consumed at metallurgical coke plants and the mass of metallurgical coke
 12 produced at coke plants were taken from the Energy Information Administration (EIA) *Quarterly Coal Report:
 13 October through December* (EIA 1998 through 2019) (see Table 4-67). Data on the volume of natural gas
 14 consumption, blast furnace gas consumption, and coke oven gas production for metallurgical coke production at
 15 integrated steel mills were obtained from the American Iron and Steel Institute (AISI) *Annual Statistical Report*
 16 (AISI 2004 through 2020) and through personal communications with AISI (AISI 2008) (see Table 4-68). The factor
 17 for the quantity of coal tar produced per ton of coking coal consumed was provided by AISI (AISI 2008). The factor
 18 for the quantity of coke breeze produced per ton of coking coal consumed was obtained through Table 2-1 of the
 19 report *Energy and Environmental Profile of the U.S. Iron and Steel Industry* (DOE 2000). Currently, data on natural
 20 gas consumption and coke oven gas production at merchant coke plants were not available and were excluded
 21 from the emission estimate. Carbon contents for metallurgical coke, coal tar, coke oven gas, and blast furnace gas
 22 were provided by the 2006 IPCC Guidelines. The C content for coke breeze was assumed to equal the C content of
 23 coke. Carbon contents for coking coal was from EIA.

24 **Table 4-67: Production and Consumption Data for the Calculation of CO₂ Emissions from
 25 Metallurgical Coke Production (Thousand Metric Tons)**

Source/Activity Data	1990	2005	2015	2016	2017	2018	2019
Metallurgical Coke Production							
Coking Coal Consumption at Coke Plants	35,269	21,259	17,879	14,955	15,910	16,635	16,261
Coke Production at Coke Plants	25,054	15,167	12,479	10,755	11,746	12,525	12,215
Coal Breeze Production	2,645	1,594	1,341	1,122	1,193	1,248	1,220
Coal Tar Production	1,058	638	536	449	477	499	488

26 **Table 4-68: Production and Consumption Data for the Calculation of CO₂ Emissions from
 27 Metallurgical Coke Production (Million ft³)**

Source/Activity Data	1990	2005	2015	2016	2017	2018	2019
Metallurgical Coke Production							
Coke Oven Gas Production	250,767	114,213	84,336	74,807	74,997	80,750	77,692
Natural Gas Consumption	599	2,996	2,338	2,077	2,103	2,275	2,189
Blast Furnace Gas Consumption	24,602	4,460	4,185	3,741	3,683	4,022	3,914

1 Iron and Steel Production

2 To estimate emissions from pig iron production in the blast furnace, the amount of carbon contained in the
3 produced pig iron and blast furnace gas were deducted from the amount of carbon contained in inputs (i.e.,
4 metallurgical coke, sinter, natural ore, pellets, natural gas, fuel oil, coke oven gas, carbonate fluxes or slagging
5 materials, and direct coal injection). The carbon contained in the pig iron, blast furnace gas, and blast furnace
6 inputs was estimated by multiplying the material-specific C content by each material type (see Table 4-69). Carbon
7 in blast furnace gas used to pre-heat the blast furnace air is combusted to form CO₂ during this process. Carbon
8 contained in blast furnace gas used as a blast furnace input was not included in the deductions to avoid double-
9 counting.

10 Emissions from steel production in EAFs were estimated by deducting the carbon contained in the steel produced
11 from the carbon contained in the EAF anode, charge carbon, and scrap steel added to the EAF. Small amounts of
12 carbon from DRI and pig iron to the EAFs were also included in the EAF calculation. For BOFs, estimates of carbon
13 contained in BOF steel were deducted from C contained in inputs such as natural gas, coke oven gas, fluxes (e.g.
14 burnt lime or dolomite), and pig iron. In each case, the carbon was calculated by multiplying material-specific
15 carbon contents by each material type (see Table 4-69). For EAFs, the amount of EAF anode consumed was
16 approximated by multiplying total EAF steel production by the amount of EAF anode consumed per metric ton of
17 steel produced (0.002 metric tons EAF anode per metric ton steel produced [AISI 2008]). The amount of flux (e.g.,
18 burnt lime or dolomite) used in pig iron production was deducted from the “Other Process Uses of Carbonates”
19 source category (CRF Source Category 2A4) to avoid double-counting.

20 Carbon dioxide emissions from the consumption of blast furnace gas and coke oven gas for other activities
21 occurring at the steel mill were estimated by multiplying the amount of these materials consumed for these
22 purposes by the material-specific carbon content (see Table 4-69).

23 Carbon dioxide emissions associated with the sinter production, direct reduced iron production, pig iron
24 production, steel production, and other steel mill activities were summed to calculate the total CO₂ emissions from
25 iron and steel production (see Table 4-62 and Table 4-63).

26 **Table 4-69: Material Carbon Contents for Iron and Steel Production**

Material	kg C/kg
Coke	0.83
Direct Reduced Iron	0.02
Dolomite	0.13
EAF Carbon Electrodes	0.82
EAF Charge Carbon	0.83
Limestone	0.12
Pig Iron	0.04
Steel	0.01

Material	kg C/GJ
Coke Oven Gas	12.1
Blast Furnace Gas	70.8

Source: IPCC (2006), Table 4.3. Coke Oven Gas and Blast Furnace Gas, Table 1.3.

27 The production process for sinter results in fugitive emissions of CH₄, which are emitted via leaks in the production
28 equipment, rather than through the emission stacks or vents of the production plants. The fugitive emissions were
29 calculated by applying Tier 1 emission factors taken from the *2006 IPCC Guidelines* for sinter production (see Table
30 4-70). Although the *1995 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1995) provide a Tier 1 CH₄ emission factor for pig
31 iron production, it is not appropriate to use because CO₂ emissions were estimated using the Tier 2 mass balance
32 methodology. The mass balance methodology makes a basic assumption that all carbon that enters the pig iron
33 production process either exits the process as part of a carbon-containing output or as CO₂ emissions; the
34 estimation of CH₄ emissions is precluded. Annual analysis of facility-level emissions reported during iron
35 production further supports this assumption and indicates that CH₄ emissions are below 500 kt CO₂ Eq. and well

1 below 0.05 percent of total national emissions. The production of direct reduced iron also results in emissions of
 2 CH₄ through the consumption of fossil fuels (e.g., natural gas, etc.); however, these emission estimates are
 3 excluded due to data limitations. Pending further analysis and resources, EPA may include these emissions in
 4 future reports to enhance completeness. EPA is still assessing the possibility of including these emissions in future
 5 reports and have not included this data in the current report.

6 **Table 4-70: CH₄ Emission Factors for Sinter and Pig Iron Production**

Material Produced	Factor	Unit
Sinter	0.07	kg CH ₄ /metric ton

Source: IPCC (2006), Table 4.2.

7 Emissions of CO₂ from sinter production, direct reduced iron production and pellet production were estimated by
 8 multiplying total national sinter production and the total national direct reduced iron production by Tier 1 CO₂
 9 emission factors (see Table 4-71). Because estimates of sinter production, direct reduced iron production, and
 10 pellet production were not available, production was assumed to equal consumption.

11 **Table 4-71: CO₂ Emission Factors for Sinter Production, Direct Reduced Iron Production, and
 12 Pellet Production**

Material Produced	Metric Ton CO ₂ /Metric Ton
Sinter	0.2
Direct Reduced Iron	0.7
Pellet Production	0.03

Source: IPCC (2006), Table 4.1.

13 The consumption of coking coal, natural gas, distillate fuel, and coal used in iron and steel production are adjusted
 14 for within the Energy chapter to avoid double-counting of emissions reported within the IPPU chapter as these
 15 fuels were consumed during non-energy related activities. More information on this methodology and examples of
 16 adjustments made between the IPPU and Energy chapters are described in Annex 2.1, Methodology for Estimating
 17 Emissions of CO₂ from Fossil Fuel Combustion.

18 Sinter consumption and pellet consumption data for 1990 through 2019 were obtained from AISI's *Annual
 19 Statistical Report* (AISI 2004 through 2020) and through personal communications with AISI (AISI 2008) (see Table
 20 4-72). In general, direct reduced iron (DRI) consumption data were obtained from the U.S. Geological Survey
 21 (USGS) *Minerals Yearbook – Iron and Steel Scrap* (USGS 1991 through 2017) and personal communication with the
 22 USGS Iron and Steel Commodity Specialist (Fenton 2015 through 2019); however, data for DRI consumed in EAFs
 23 were not available for the years 1990 and 1991. EAF DRI consumption in 1990 and 1991 was calculated by
 24 multiplying the total DRI consumption for all furnaces by the EAF share of total DRI consumption in 1992. Also,
 25 data for DRI consumed in BOFs were not available for the years 1990 through 1993. BOF DRI consumption in 1990
 26 through 1993 was calculated by multiplying the total DRI consumption for all furnaces (excluding EAFs and cupola)
 27 by the BOF share of total DRI consumption (excluding EAFs and cupola) in 1994.

28 The Tier 1 CO₂ emission factors for sinter production, direct reduced iron production and pellet production were
 29 obtained through the *2006 IPCC Guidelines* (IPCC 2006). Time-series data for pig iron production, coke, natural gas,
 30 fuel oil, sinter, and pellets consumed in the blast furnace; pig iron production; and blast furnace gas produced at
 31 the iron and steel mill and used in the metallurgical coke ovens and other steel mill activities were obtained from
 32 AISI's *Annual Statistical Report* (AISI 2004 through 2020) and through personal communications with AISI (AISI
 33 2008) (see Table 4-72 and Table 4-73).

34 Data for EAF steel production, flux, EAF charge carbon, and natural gas consumption were obtained from AISI's
 35 *Annual Statistical Report* (AISI 2004 through 2020) and through personal communications with AISI (AISI 2006
 36 through 2016 and AISI 2008). The factor for the quantity of EAF anode consumed per ton of EAF steel produced
 37 was provided by AISI (AISI 2008). Data for BOF steel production, flux, natural gas, natural ore, pellet, sinter
 38 consumption as well as BOF steel production were obtained from AISI's *Annual Statistical Report* (AISI 2004
 39 through 2020) and through personal communications with AISI (AISI 2008). Data for EAF and BOF scrap steel, pig

1 iron, and DRI consumption were obtained from the USGS *Minerals Yearbook – Iron and Steel Scrap* (USGS 1991
 2 through 2017). Data on coke oven gas and blast furnace gas consumed at the iron and steel mill (other than in the
 3 EAF, BOF, or blast furnace) were obtained from AISI’s *Annual Statistical Report* (AISI 2004 through 2020) and
 4 through personal communications with AISI (AISI 2008).

5 Data on blast furnace gas and coke oven gas sold for use as synthetic natural gas were obtained from EIA’s *Natural*
 6 *Gas Annual* (EIA 2020). Carbon contents for direct reduced iron, EAF carbon electrodes, EAF charge carbon,
 7 limestone, dolomite, pig iron, and steel were provided by the *2006 IPCC Guidelines*. The carbon contents for
 8 natural gas, fuel oil, and direct injection coal were obtained from EIA (EIA 2017c) and EPA (EPA 2010). Heat
 9 contents for fuel oil and direct injection coal were obtained from EIA (EIA 1992, 2011); natural gas heat content
 10 was obtained from Table 37 of AISI’s *Annual Statistical Report* (AISI 2004 through 2020). Heat contents for coke
 11 oven gas and blast furnace gas were provided in Table 37 of AISI’s *Annual Statistical Report* (AISI 2004 through
 12 2020) and confirmed by AISI staff (Carroll 2016).

13 **Table 4-72: Production and Consumption Data for the Calculation of CO₂ and CH₄ Emissions**
 14 **from Iron and Steel Production (Thousand Metric Tons)**

Source/Activity Data	1990	2005	2015	2016	2017	2018	2019
Sinter Production							
Sinter Production	12,239	8,315	5,079	4,385	4,347	4,687	4,378
Direct Reduced Iron Production							
Direct Reduced Iron Production	516	1,303	2,722	C	C	C	C
Pellet Production							
Pellet Production	60,563	50,096	32,146	28,967	28,916	30,793	28,916
Pig Iron Production							
Coke Consumption	24,946	13,832	7,969	7,124	7,101	7,618	7,291
Pig Iron Production	49,669	37,222	25,436	22,293	22,395	24,058	22,302
Direct Injection Coal Consumption	1,485	2,573	2,275	1,935	2,125	2,569	2,465
EAF Steel Production							
EAF Anode and Charge Carbon Consumption	67	1,127	1,072	1,120	1,127	1,133	1,137
Scrap Steel Consumption	42,691	46,600	44,000	C	C	C	C
Flux Consumption	319	695	998	998	998	998	998
EAF Steel Production	33,511	52,194	49,451	52,589	55,825	58,904	61,172
BOF Steel Production							
Pig Iron Consumption	47,307	34,400	20,300	C	C	C	C
Scrap Steel Consumption	14,713	11,400	4,530	C	C	C	C
Flux Consumption	576	582	454	408	408	408	363
BOF Steel Production	43,973	42,705	29,396	25,888	25,788	27,704	26,591

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15 **Table 4-73: Production and Consumption Data for the Calculation of CO₂ Emissions from**
 16 **Iron and Steel Production (Million ft³ unless otherwise specified)**

Source/Activity Data	1990	2005	2015	2016	2017	2018	2019
Pig Iron Production							
Natural Gas Consumption	56,273	59,844	43,294	38,396	38,142	40,204	37,934
Fuel Oil Consumption (thousand gallons)	163,397	16,170	9,326	6,124	4,352	3,365	2,321
Coke Oven Gas Consumption	22,033	16,557	13,921	12,404	12,459	13,337	12,926
Blast Furnace Gas Production	1,439,380	1,299,980	874,670	811,005	808,499	871,860	836,033
EAF Steel Production							
Natural Gas Consumption	15,905	19,985	8,751	3,915	8,105	8,556	9,115
BOF Steel Production							
Coke Oven Gas Consumption	3,851	524	386	367	374	405	389
Other Activities							

Coke Oven Gas Consumption	224,883	97,132	70,029	62,036	62,164	67,008	64,377
Blast Furnace Gas Consumption	1,414,778	1,295,520	870,485	807,264	804,816	867,838	832,119

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

The estimates of CO₂ emissions from metallurgical coke production are based on assessing uncertainties in material production and consumption data and average carbon contents. Uncertainty is associated with the total U.S. coking coal consumption, total U.S. coke production, and materials consumed during this process. Data for coking coal consumption and metallurgical coke production are from different data sources (EIA) than data for other carbonaceous materials consumed at coke plants (AISI), which does not include data for merchant coke plants. There is uncertainty associated with the fact that coal tar and coke breeze production were estimated based on coke production because coal tar and coke breeze production data were not available. Since merchant coke plant data is not included in the estimate of other carbonaceous materials consumed at coke plants, the mass balance equation for CO₂ from metallurgical coke production cannot be reasonably completed. Therefore, for the purpose of this analysis, uncertainty parameters are applied to primary data inputs to the calculation (i.e., coking coal consumption and metallurgical coke production) only.

The estimates of CO₂ emissions from iron and steel production are based on material production and consumption data and average C contents. There is uncertainty associated with the assumption that pellet production, direct reduced iron and sinter consumption are equal to production. There is uncertainty with the representativeness of the associated IPCC default emission factors. There is uncertainty associated with the assumption that all coal used for purposes other than coking coal is for direct injection coal. There is also uncertainty associated with the C contents for pellets, sinter, and natural ore, which are assumed to equal the C contents of direct reduced iron, when consumed in the blast furnace. There is uncertainty associated with the consumption of natural ore under current industry practices. For EAF steel production, there is uncertainty associated with the amount of EAF anode and charge carbon consumed due to inconsistent data throughout the time series. Also for EAF steel production, there is uncertainty associated with the assumption that 100 percent of the natural gas attributed to “steelmaking furnaces” by AISI is process-related and nothing is combusted for energy purposes. Uncertainty is also associated with the use of process gases such as blast furnace gas and coke oven gas. Data are not available to differentiate between the use of these gases for processes at the steel mill versus for energy generation (i.e., electricity and steam generation); therefore, all consumption is attributed to iron and steel production. These data and carbon contents produce a relatively accurate estimate of CO₂ emissions. However, there are uncertainties associated with each.

For calculating the emissions estimates from iron and steel and metallurgical coke production, EPA utilizes a number of data points taken from the AISI *Annual Statistical Report (ASR)*. This report serves as a benchmark for information on steel companies in United States, regardless if they are a member of AISI, which represents integrated producers (i.e., blast furnace and EAF). During the compilation of the 1990 through 2016 Inventory report EPA initiated conversation with AISI to better understand and update the qualitative and quantitative uncertainty metrics associated with AISI data elements. AISI estimates their data collection response rate to range from 75 to 90 percent, with certain sectors of the iron and steel industry not being covered by the ASR. Therefore, there is some inherent uncertainty in the values provided in the AISI ASR, including material production and consumption data. There is also some uncertainty to which materials produced are exported to Canada. As indicated in the introduction to this section, the trend for integrated facilities has moved to more use of EAFs and fewer BOFs. This trend may not be completely captured in the current data which also increases uncertainty. EPA currently uses an uncertainty range of ±10 percent for the primary data inputs to calculate overall uncertainty from iron and steel production, consistent with *2006 IPCC Guidelines*. During EPA’s discussion with AISI, AISI noted that an uncertainty range of ±5 percent would be a more appropriate approximation to reflect their coverage of integrated steel producers in the United States. EPA will continue to assess the best range of uncertainty for these values.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-74 for metallurgical coke production and iron and steel production. Total CO₂ emissions from metallurgical coke production and iron and steel production for 2018 were estimated to be between 35.2 and 50.4 MMT CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 17 percent below and 18 percent above the emission estimate of 41.3 MMT CO₂ Eq. Total CH₄ emissions from metallurgical coke production and iron and steel production for 2018 were estimated to be between 0.006 and 0.009 MMT CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 20 percent below and 20 percent above the emission estimate of 0.008 MMT CO₂ Eq.

Table 4-74: Approach 2 Quantitative Uncertainty Estimates for CO₂ and CH₄ Emissions from Iron and Steel Production and Metallurgical Coke Production (MMT CO₂ Eq. and Percent)

Source	Gas	2018 Emission Estimate (MMT CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a (%)			
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Metallurgical Coke & Iron and Steel Production	CO ₂	41.3	35.2	50.4	-17%	+18%
Metallurgical Coke & Iron and Steel Production	CH ₄	+	+	+	-20%	+20%

+ Does not exceed 0.05 MMT CO₂ Eq.

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

Methodological approaches were applied to the entire time series to ensure consistency in emissions from 1990 through 2018.

QA/QC and Verification

For more information on the general QA/QC process applied to this source category, consistent with Volume 1, Chapter 6 of the *2006 IPCC Guidelines*, see the QA/QC and Verification Procedures section in the introduction of the IPPU chapter.

Recalculations Discussion

No recalculations or changes to calculation methodology were made to the iron and steel production and metallurgical coke production inventory in 2019.

Planned Improvements

Future improvements involve improving activity data and emission factor sources for CO₂ and CH₄ emissions estimations from pellet production. EPA will also evaluate and analyze data reported under EPA's GHGRP to improve the emission estimates for this and other Iron and Steel Production process categories. Particular attention will be made to ensure time-series consistency of the emissions estimates presented in future Inventory reports, consistent with IPCC and UNFCCC guidelines. This is required as the facility-level reporting data from EPA's GHGRP, with the program's initial requirements for reporting of emissions in calendar year 2010, are not available for all inventory years (i.e., 1990 through 2009) as required for this Inventory. 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.⁶³ This is a medium-term improvement and EPA estimates that earliest this improvement could be incorporated is the 2022 Inventory submission.

Additional improvements include accounting for emission estimates for the production of metallurgical coke in the Energy chapter as well as identifying the amount of carbonaceous materials, other than coking coal, consumed at

⁶³ See <http://www.ipcc-nggip.iges.or.jp/public/tb/TFI_Technical_Bulletin_1.pdf>.

1 merchant coke plants. Other potential improvements include identifying the amount of coal used for direct
 2 injection and the amount of coke breeze, coal tar, and light oil produced during coke production. Efforts will also
 3 be made to identify information to better characterize emissions from the use of process gases and fuels within
 4 the Energy and IPPU chapters. Additional efforts will be made to improve the reporting between the IPPU and
 5 Energy chapters, particularly the inclusion of a quantitative summary of the carbon balance in the United States.
 6 This planned improvement is a long-term improvement and is still in development; therefore, it is not included in
 7 this current Inventory report and is not expected until a future (i.e., 2022) Inventory submission.

8 EPA also received comments during the Expert Review cycle of a previous (i.e., 1990 through 2016) Inventory on
 9 recommendations to improve the description of the iron and steel industry and emissive processes. EPA began
 10 incorporating some of these recommendations into a previous Inventory (i.e., 1990 through 2016) and will require
 11 some additional time to implement other substantive changes.

12 4.18 Ferroalloy Production (CRF Source 13 Category 2C2)

14 Carbon dioxide (CO₂) and methane (CH₄) are emitted from the production of several ferroalloys. Ferroalloys are
 15 composites of iron (Fe) and other elements such as silicon (Si), manganese (Mn), and chromium (Cr). Emissions
 16 from fuels consumed for energy purposes during the production of ferroalloys are accounted for in the Energy
 17 chapter. Emissions from the production of two types of ferrosilicon (25 to 55 percent and 56 to 95 percent silicon),
 18 silicon metal (96 to 99 percent silicon), and miscellaneous alloys (32 to 65 percent silicon) have been calculated.
 19 Emissions from the production of ferrochromium and ferromanganese are not included here because of the small
 20 number of manufacturers of these materials in the United States, and therefore, government information
 21 disclosure rules prevent the publication of production data for these production facilities.

22 Similar to emissions from the production of iron and steel, CO₂ is emitted when metallurgical coke is oxidized
 23 during a high-temperature reaction with iron and the selected alloying element. Due to the strong reducing
 24 environment, CO is initially produced and eventually oxidized to CO₂. A representative reaction equation for the
 25 production of 50 percent ferrosilicon (FeSi) is given below:



27 While most of the carbon contained in the process materials is released to the atmosphere as CO₂, a percentage is
 28 also released as CH₄ and other volatiles. The amount of CH₄ that is released is dependent on furnace efficiency,
 29 operation technique, and control technology.

30 When incorporated in alloy steels, ferroalloys are used to alter the material properties of the steel. Ferroalloys are
 31 used primarily by the iron and steel industry, and production trends closely follow that of the iron and steel
 32 industry. As of 2016, 11 facilities in the United States produce ferroalloys (USGS 2020).

33 Emissions of CO₂ from ferroalloy production in 2019 were 1.6 MMT CO₂ Eq. (1,598 kt CO₂) (see Table 4-75 and
 34 Table 4-76), which is a 26 percent reduction since 1990. Emissions of CH₄ from ferroalloy production in 2019 were
 35 0.01 MMT CO₂ Eq. (0.4 kt CH₄), which is a 34 percent decrease since 1990. These decreases in emissions were
 36 mostly caused by the shutdown of two ferroalloy facilities during 2018.

37 **Table 4-75: CO₂ and CH₄ Emissions from Ferroalloy Production (MMT CO₂ Eq.)**

Gas	1990	2005	2015	2016	2017	2018	2019
CO ₂	2.2	1.4	2.0	1.8	2.0	2.1	1.6
CH ₄	+	+	+	+	+	+	+
Total	2.2	1.4	2.0	1.8	2.0	2.1	1.6

+ Does not exceed 0.05 MMT CO₂ Eq.

1 **Table 4-76: CO₂ and CH₄ Emissions from Ferroalloy Production (kt)**

Gas	1990	2005	2015	2016	2017	2018	2019
CO ₂	2,152	1,392	1,960	1,796	1,975	2,063	1,598
CH ₄	1	+	1	1	1	1	+

+ Does not exceed 0.5 kt CO₂ Eq.

2 Methodology

3 Emissions of CO₂ and CH₄ from ferroalloy production were calculated⁶⁴ using a Tier 1 method from the 2006 IPCC
 4 *Guidelines* by multiplying annual ferroalloy production by material-specific default emission factors provided by
 5 IPCC (IPCC 2006). The Tier 1 equations for CO₂ and CH₄ emissions are as follows:

$$6 E_{CO_2} = \sum_i (MP_i \times EF_i)$$

7 where,

8 E_{CO₂} = CO₂ emissions, metric tons
 9 MP_{*i*} = Production of ferroalloy type *i*, metric tons
 10 EF_{*i*} = Generic emission factor for ferroalloy type *i*, metric tons CO₂/metric ton specific
 11 ferroalloy product
 12

$$13 E_{CH_4} = \sum_i (MP_i \times EF_i)$$

14 where,

15 E_{CH₄} = CH₄ emissions, kg
 16 MP_{*i*} = Production of ferroalloy type *i*, metric tons
 17 EF_{*i*} = Generic emission factor for ferroalloy type *i*, kg CH₄/metric ton specific ferroalloy
 18 product

19 Default emission factors were used because country-specific emission factors are not currently available. The
 20 following emission factors were used to develop annual CO₂ and CH₄ estimates:

- 21 • Ferrosilicon, 25 to 55 percent Si and Miscellaneous Alloys, 32 to 65 percent Si: 2.5 metric tons CO₂/metric
 22 ton of alloy produced, 1.0 kg CH₄/metric ton of alloy produced.
- 23 • Ferrosilicon, 56 to 95 percent Si: 4.0 metric tons CO₂/metric ton alloy produced, 1.0 kg CH₄/metric ton of
 24 alloy produced.
- 25 • Silicon Metal: 5.0 metric tons CO₂/metric ton metal produced, 1.2 kg CH₄/metric ton metal produced.

26 It was assumed that 100 percent of the ferroalloy production was produced using petroleum coke in an electric arc
 27 furnace process (IPCC 2006), although some ferroalloys may have been produced with coking coal, wood, other
 28 biomass, or graphite carbon inputs. The amount of petroleum coke consumed in ferroalloy production was
 29 calculated assuming that the petroleum coke used is 90 percent carbon (C) and 10 percent inert material (Onder
 30 and Bagdoyan 1993).

31 The use of petroleum coke for ferroalloy production is adjusted for within the Energy chapter as this fuel was
 32 consumed during non-energy related activities. Additional information on the adjustments made within the Energy
 33 sector for Non-Energy Use of Fuels is described in both the Methodology section of CO₂ from Fossil Fuel

⁶⁴ EPA has not integrated aggregated facility-level GHGRP information to inform these estimates. The aggregated information (e.g., activity data and emissions) associated with production of ferroalloys did not meet criteria to shield underlying confidential business information (CBI) from public disclosure.

1 Combustion (3.1 Fossil Fuel Combustion (CRF Source Category 1A)) and Annex 2.1, Methodology for Estimating
 2 Emissions of CO₂ from Fossil Fuel Combustion.

3 Ferroalloy production data for 1990 through 2019 (see Table 4-77) were obtained from the U.S. Geological Survey
 4 (USGS) through the *Minerals Yearbook: Silicon* (USGS 1996 through 2015) and the *Mineral Industry Surveys: Silicon*
 5 (USGS 2014, 2015b, 2016b, 2017, 2018b, 2019, 2020). The following data were available from the USGS
 6 publications for the time series:

- 7 • Ferrosilicon, 25 to 55 percent Si: Annual production data were available from 1990 through 2010.
- 8 • Ferrosilicon, 56 to 95 percent Si: Annual production data were available from 1990 through 2010.
- 9 • Silicon Metal: Annual production data were available from 1990 through 2005. The production data for
 10 2005 were used as proxy for 2006 through 2010.
- 11 • Miscellaneous Alloys, 32 to 65 percent Si: Annual production data were available from 1990 through
 12 1998. Starting 1999, USGS reported miscellaneous alloys and ferrosilicon containing 25 to 55 percent
 13 silicon as a single category.

14 Starting with the 2011 publication, USGS ceased publication of production quantity by ferroalloy product and
 15 began reporting all the ferroalloy production data as a single category (i.e., Total Silicon Materials Production). This
 16 is due to the small number of ferroalloy manufacturers in the United States and government information
 17 disclosure rules. Ferroalloy product shares developed from the 2010 production data (i.e., ferroalloy product
 18 production/total ferroalloy production) were used with the total silicon materials production quantity to estimate
 19 the production quantity by ferroalloy product type for 2011 through 2019 (USGS 2013, 2014, 2015b, 2016b, 2017,
 20 2018b, 2019, 2020).

21 **Table 4-77: Production of Ferroalloys (Metric Tons)**

Year	Ferrosilicon 25%-55%	Ferrosilicon 56%-95%	Silicon Metal	Misc. Alloys 32-65%
1990	321,385	109,566	145,744	72,442
2005	123,000	86,100	148,000	NA
2015	180,372	159,151	174,477	NA
2016	165,282	145,837	159,881	NA
2017	181,775	160,390	175,835	NA
2018	189,846	167,511	183,642	NA
2019	147,034	129,736	142,229	NA

NA - Not Available for product type, aggregated along with ferrosilicon (25-55% Si)

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

24 Annual ferroalloy production was reported by the USGS in three broad categories until the 2010 publication:
 25 ferroalloys containing 25 to 55 percent silicon (including miscellaneous alloys), ferroalloys containing 56 to 95
 26 percent silicon, and silicon metal (through 2005 only, 2005 value used as proxy for 2005 through 2010). Starting
 27 with the 2011 *Minerals Yearbook*, USGS started reporting all the ferroalloy production under a single category:
 28 total silicon materials production. The total silicon materials quantity was allocated across the three categories
 29 based on the 2010 production shares for the three categories. Refer to the Methodology section for further
 30 details. Additionally, production data for silvery pig iron (alloys containing less than 25 percent silicon) are not
 31 reported by the USGS to avoid disclosing proprietary company data. Emissions from this production category,
 32 therefore, were not estimated.

33 Also, some ferroalloys may be produced using wood or other biomass as a primary or secondary carbon source
 34 (carbonaceous reductants); however, information and data regarding these practices were not available. Emissions
 35 from ferroalloys produced with wood or other biomass would not be counted under this source because wood-

based carbon is of biogenic origin.⁶⁵ Even though emissions from ferroalloys produced with coking coal or graphite inputs would be counted in national trends, they may be generated with varying amounts of CO₂ per unit of ferroalloy produced. The most accurate method for these estimates would be to base calculations on the amount of reducing agent used in the process, rather than the amount of ferroalloys produced. These data, however, were not available, and are also often considered confidential business information.

Emissions of CH₄ from ferroalloy production will vary depending on furnace specifics, such as type, operation technique, and control technology. Higher heating temperatures and techniques such as sprinkle charging will reduce CH₄ emissions; however, specific furnace information was not available or included in the CH₄ emission estimates.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-78. Ferroalloy production CO₂ emissions from 2018 were estimated to be between 1.8 and 2.3 MMT CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 12 percent below and 12 percent above the emission estimate of 2.1 MMT CO₂ Eq. Ferroalloy production CH₄ emissions were estimated to be between a range of approximately 12 percent below and 12 percent above the emission estimate of 0.01 MMT CO₂ Eq.

Table 4-78: Approach 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Ferroalloy Production (MMT CO₂ Eq. and Percent)

Source	Gas	2018 Emission Estimate (MMT CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a (MMT CO ₂ Eq.)			
			Lower Bound	Upper Bound	Lower Bound (%)	Upper Bound (%)
Ferroalloy Production	CO ₂	2.1	1.8	2.3	-12%	+12%
Ferroalloy Production	CH ₄	+	+	+	-12%	+12%

+ Does not exceed 0.05 MMT CO₂ Eq.

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

Methodological approaches were applied to the entire time series to ensure consistency in emissions from 1990 through 2018. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

For more information on the general QA/QC process applied to this source category, consistent with Volume 1, Chapter 6 of the *2006 IPCC Guidelines*, see the QA/QC and Verification Procedures section in the introduction of the IPPU chapter and Annex 8.

Recalculations Discussion

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

The carbon factors used to determine the amount of petroleum coke used for ferroalloy production were updated to be consistent with the factors used in the fossil fuel combustion estimates. This update did not have an impact on process-related ferroalloy emissions presented here but did impact the amount of petroleum coke subtracted from energy use as part of the CO₂ Emissions from Fossil Fuel Combustion calculations (see Annex 2.3 for more information).

⁶⁵ Emissions and sinks of biogenic carbon are accounted for in the Land Use, Land-Use Change, and Forestry chapter.

1 Planned Improvements

2 Pending available resources and prioritization of improvements for more significant sources, EPA will continue to
3 evaluate and analyze data reported under EPA’s GHGRP that would be useful to improve the emission estimates
4 and category-specific QC procedures for the Ferroalloy Production source category. Given the small number of
5 facilities and reporting thresholds, particular attention will be made to ensure completeness and time-series
6 consistency of the emissions estimates presented in future Inventory reports, consistent with IPCC and UNFCCC
7 guidelines. This is required as the facility-level reporting data from EPA’s GHGRP, with the program’s initial
8 requirements for reporting of emissions in calendar year 2010, are not available for all inventory years (i.e., 1990
9 through 2009) as required for this Inventory. In implementing improvements and integration of data from EPA’s
10 GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will be relied
11 upon.⁶⁶ This is a long-term planned improvement and EPA is still assessing the possibility of incorporating this
12 improvement into the Inventory. This improvement has not been included in the current Inventory report.

13 4.19 Aluminum Production (CRF Source 14 Category 2C3)

15 Aluminum is a light-weight, malleable, and corrosion-resistant metal that is used in many manufactured products,
16 including aircraft, automobiles, bicycles, and kitchen utensils. As of recent reporting, the United States was the
17 twelfth largest producer of primary aluminum, with approximately 1 percent of the world total production (USGS
18 2019). The United States was also a major importer of primary aluminum. The production of primary aluminum—
19 in addition to consuming large quantities of electricity—results in process-related emissions of carbon dioxide
20 (CO₂) and two perfluorocarbons (PFCs): perfluoromethane (CF₄) and perfluoroethane (C₂F₆).

21 Carbon dioxide is emitted during the aluminum smelting process when alumina (aluminum oxide, Al₂O₃) is reduced
22 to aluminum using the Hall-Heroult reduction process. The reduction of the alumina occurs through electrolysis in
23 a molten bath of natural or synthetic cryolite (Na₃AlF₆). The reduction cells contain a carbon (C) lining that serves
24 as the cathode. Carbon is also contained in the anode, which can be a C mass of paste, coke briquettes, or
25 prebaked C blocks from petroleum coke. During reduction, most of this C is oxidized and released to the
26 atmosphere as CO₂.

27 Process emissions of CO₂ from aluminum production were estimated to be 1.9 MMT CO₂ Eq. (1,880 kt) in 2019 (see
28 Table 4-79). The C anodes consumed during aluminum production consist of petroleum coke and, to a minor
29 extent, coal tar pitch. The petroleum coke portion of the total CO₂ process emissions from aluminum production is
30 considered to be a non-energy use of petroleum coke, and is accounted for here and not under the CO₂ from Fossil
31 Fuel Combustion source category of the Energy sector. Similarly, the coal tar pitch portion of these CO₂ process
32 emissions is accounted for here.

33 **Table 4-79: CO₂ Emissions from Aluminum Production (MMT CO₂ Eq. and kt)**

Year	MMT CO ₂ Eq.	kt
1990	6.8	6,831
2005	4.1	4,142
2015	2.8	2,767
2016	1.3	1,334
2017	1.2	1,205

⁶⁶ See <http://www.ipcc-nggip.iges.or.jp/public/tb/TFI_Technical_Bulletin_1.pdf>.

2018	1.5	1,451
2019	1.9	1,880

1 In addition to CO₂ emissions, the aluminum production industry is also a source of PFC emissions. During the
2 smelting process, when the alumina ore content of the electrolytic bath falls below critical levels required for
3 electrolysis, rapid voltage increases occur, which are termed High Voltage Anode Effects (HVAEs) HVAEs cause C
4 from the anode and fluorine from the dissociated molten cryolite bath to combine, thereby producing fugitive
5 emissions of CF₄ and C₂F₆. In general, the magnitude of emissions for a given smelter and level of production
6 depends on the frequency and duration of these anode effects. As the frequency and duration of the anode effects
7 increase, emissions increase. Another type of anode effect, Low Voltage Anode Effects (LVAEs), became a concern
8 in the early 2010s as the aluminum industry increasingly began to use cell technologies with higher amperage and
9 additional anodes (IPCC 2019). LVAEs emit CF₄, and are included in PFC emission totals from 2006 forward.

10 Since 1990, emissions of CF₄ and C₂F₆ have declined by 92 percent and 90 percent, respectively, to 1.4 MMT CO₂
11 Eq. of CF₄ (0.19 kt) and 0.4 MMT CO₂ Eq. of C₂F₆ (0.03 kt) in 2019 as shown in

12 Table 4-80 and Table 4-81. This decline is due both to reductions in domestic aluminum production and to actions
13 taken by aluminum smelting companies to reduce the frequency and duration of anode effects. These actions
14 include technology and operational changes such as employee training, use of computer monitoring, and changes
15 in alumina feeding techniques. Since 1990, aluminum production has declined by 72 percent, while the combined
16 CF₄ and C₂F₆ emission rate (per metric ton of aluminum produced) has been reduced by 70 percent. PFC emissions
17 increased by approximately 8 percent between 2018 and 2019 due to increases in aluminum production. The
18 decrease in the ratio of C₂F₆ to CF₄ emissions between 2018 and 2019 may be due to a combination of a decrease
19 in the measured C₂F₆ to CF₄ weight fraction at some facilities and changes in how production is distributed among
20 facilities with different C₂F₆ to CF₄ weight fractions.

21 **Table 4-80: PFC Emissions from Aluminum Production (MMT CO₂ Eq.)**

Year	CF ₄	C ₂ F ₆	Total
1990	17.9	3.5	21.5
2005	2.9	0.6	3.4
2015	1.6	0.5	2.1
2016	1.0	0.4	1.4
2017	0.7	0.4	1.1
2018	1.2	0.4	1.6
2019	1.4	0.4	1.8

Note: Totals may not sum due to independent rounding.

22

23 **Table 4-81: PFC Emissions from Aluminum Production (kt)**

Year	CF ₄	C ₂ F ₆
1990	2.4	0.3
2005	0.4	+
2015	0.2	+
2016	0.1	+
2017	0.1	+
2018	0.2	+
2019	0.2	+

+ Does not exceed 0.05 kt.

1 In 2019, U.S. primary aluminum production totaled approximately 1.1 million metric tons, a 26 percent increase
2 from 2018 production levels (USAA 2020). In 2019, three companies managed production at seven operational
3 primary aluminum smelters. Two smelters operated at full capacity during 2019, while the other five operated at
4 reduced capacity (USGS 2020). During 2019, monthly U.S. primary aluminum production was higher for every
5 month when compared to the corresponding months in 2018, with the exception of December (USAA 2020).
6 For 2020, total production for the January to August period was approximately 0.7 million metric tons compared to
7 0.8 million metric tons for the same period in 2018, a 4.5 percent decrease (USAA 2020). Based on the decrease in
8 production, process CO₂ and PFC emissions may be lower in 2020 compared to 2019 if there are no significant
9 changes in process controls at operational facilities.

10 Methodology

11 Process CO₂ and PFC (i.e., CF₄ and C₂F₆) emission estimates from primary aluminum production for 2010 through
12 2019 are available from EPA’s GHGRP—Subpart F (Aluminum Production) (EPA 2020). Under EPA’s GHGRP,
13 facilities began reporting primary aluminum production process emissions (for 2010) in 2011; as a result, GHGRP
14 data (for 2010 through 2019) are available to be incorporated into the Inventory. EPA’s GHGRP mandates that all
15 facilities that contain an aluminum production process must report: CF₄ and C₂F₆ emissions from anode effects in
16 all prebake and Søderberg electrolysis cells, CO₂ emissions from anode consumption during electrolysis in all
17 prebake and Søderberg cells, and all CO₂ emissions from onsite anode baking. To estimate the process emissions,
18 EPA’s GHGRP uses the process-specific equations detailed in Subpart F (aluminum production).⁶⁷ These equations
19 are based on the Tier 2/Tier 3 IPCC (2006) methods for primary aluminum production, and Tier 1 methods when
20 estimating missing data elements. It should be noted that the same methods (i.e., *2006 IPCC Guidelines*) were used
21 for estimating the emissions prior to the availability of the reported GHGRP data in the Inventory. Prior to 2010,
22 aluminum production data were provided through EPA’s Voluntary Aluminum Industrial Partnership (VAIP).

23 As previously noted, the use of petroleum coke for aluminum production is adjusted for within the Energy chapter
24 as this fuel was consumed during non-energy related activities. Additional information on the adjustments made
25 within the Energy sector for Non-Energy Use of Fuels is described in both the Methodology section of CO₂ from
26 Fossil Fuel Combustion (3.1 Fossil Fuel Combustion (CRF Source Category 1A)) and Annex 2.1, Methodology for
27 Estimating Emissions of CO₂ from Fossil Fuel Combustion.

28 Process CO₂ Emissions from Anode Consumption and Anode Baking

29 Carbon dioxide emission estimates for the years prior to the introduction of EPA’s GHGRP in 2010 were estimated
30 using *2006 IPCC Guidelines* methods, but individual facility reported data were combined with process-specific
31 emissions modeling. These estimates were based on information previously gathered from EPA’s Voluntary
32 Aluminum Industrial Partnership (VAIP) program, U.S. Geological Survey (USGS) Mineral Commodity reviews, and
33 The Aluminum Association (USAA) statistics, among other sources. Since pre- and post-GHGRP estimates use the
34 same methodology, emission estimates are comparable across the time series.

35 Most of the CO₂ emissions released during aluminum production occur during the electrolysis reaction of the C
36 anode, as described by the following reaction:



38 For prebake smelter technologies, CO₂ is also emitted during the anode baking process. These emissions can
39 account for approximately 10 percent of total process CO₂ emissions from prebake smelters.

40 Depending on the availability of smelter-specific data, the CO₂ emitted from electrolysis at each smelter was
41 estimated from: (1) the smelter’s annual anode consumption, (2) the smelter’s annual aluminum production and

⁶⁷ Code of Federal Regulations, Title 40: Protection of Environment, Part 98: Mandatory Greenhouse Gas Reporting, Subpart F—Aluminum Production. See <www.epa.gov/ghgreporting/documents/pdf/infosheets/aluminumproduction.pdf>.

1 rate of anode consumption (per ton of aluminum produced) for previous and/or following years, or (3) the
 2 smelter’s annual aluminum production and IPCC default CO₂ emission factors. The first approach tracks the
 3 consumption and carbon content of the anode, assuming that all C in the anode is converted to CO₂. Sulfur, ash,
 4 and other impurities in the anode are subtracted from the anode consumption to arrive at a C consumption figure.
 5 This approach corresponds to either the IPCC Tier 2 or Tier 3 method, depending on whether smelter-specific data
 6 on anode impurities are used. The second approach interpolates smelter-specific anode consumption rates to
 7 estimate emissions during years for which anode consumption data are not available. This approach avoids
 8 substantial errors and discontinuities that could be introduced by reverting to Tier 1 methods for those years. The
 9 last approach corresponds to the IPCC Tier 1 method (IPCC 2006) and is used in the absence of present or historic
 10 anode consumption data.

11 The equations used to estimate CO₂ emissions in the Tier 2 and 3 methods vary depending on smelter type (IPCC
 12 2006). For Prebake cells, the process formula accounts for various parameters, including net anode consumption,
 13 and the sulfur, ash, and impurity content of the baked anode. For anode baking emissions, the formula accounts
 14 for packing coke consumption, the sulfur and ash content of the packing coke, as well as the pitch content and
 15 weight of baked anodes produced. For Söderberg cells, the process formula accounts for the weight of paste
 16 consumed per metric ton of aluminum produced, and pitch properties, including sulfur, hydrogen, and ash
 17 content.

18 Through the VAIP, anode consumption (and some anode impurity) data have been reported for 1990, 2000, 2003,
 19 2004, 2005, 2006, 2007, 2008, and 2009. Where available, smelter-specific process data reported under the VAIP
 20 were used; however, if the data were incomplete or unavailable, information was supplemented using industry
 21 average values recommended by IPCC (2006). Smelter-specific CO₂ process data were provided by 18 of the 23
 22 operating smelters in 1990 and 2000, by 14 out of 16 operating smelters in 2003 and 2004, 14 out of 15 operating
 23 smelters in 2005, 13 out of 14 operating smelters in 2006, 5 out of 14 operating smelters in 2007 and 2008, and 3
 24 out of 13 operating smelters in 2009. For years where CO₂ emissions data or CO₂ process data were not reported
 25 by these companies, estimates were developed through linear interpolation, and/or assuming representative (e.g.,
 26 previously reported or industry default) values.

27 In the absence of any previous historical smelter-specific process data (i.e., 1 out of 13 smelters in 2009; 1 out of
 28 14 smelters in 2006, 2007, and 2008; 1 out of 15 smelters in 2005; and 5 out of 23 smelters between 1990 and
 29 2003), CO₂ emission estimates were estimated using Tier 1 Söderberg and/or Prebake emission factors (metric ton
 30 of CO₂ per metric ton of aluminum produced) from IPCC (2006).

31 **Process PFC Emissions from Anode Effects**

32 **High Voltage Anode Effects**

33 Smelter-specific PFC emissions from aluminum production for 2010 through 2019 were reported to EPA under its
 34 GHGRP. To estimate their PFC emissions from HVAEs and report them under EPA’s GHGRP, smelters use an
 35 approach identical to the Tier 3 approach in the *2006 IPCC Guidelines* (IPCC 2006). Specifically, they use a smelter-
 36 specific slope coefficient as well as smelter-specific operating data to estimate an emission factor using the
 37 following equation:

$$38 \quad PFC = S \times AE$$

$$39 \quad AE = F \times D$$

40 where,

41			
42	PFC	=	CF ₄ or C ₂ F ₆ , kg/MT aluminum
43	S	=	Slope coefficient, PFC/AE
44	AE	=	Anode effect, minutes/cell-day
45	F	=	Anode effect frequency per cell-day
46	D	=	Anode effect duration, minutes
47			

1 They then multiply this emission factor by aluminum production to estimate PFC emissions from HVAEs. All U.S.
2 aluminum smelters are required to report their emissions under EPA’s GHGRP.

3 Perfluorocarbon emissions for the years prior to 2010 were estimated using the same equation, but the slope-
4 factor used for some smelters was technology-specific rather than smelter-specific, making the method a Tier 2
5 rather than a Tier 3 approach for those smelters. Emissions and background data were reported to EPA under the
6 VAIP. For 1990 through 2009, smelter-specific slope coefficients were available and were used for smelters
7 representing between 30 and 94 percent of U.S. primary aluminum production. The percentage changed from year
8 to year as some smelters closed or changed hands and as the production at remaining smelters fluctuated. For
9 smelters that did not report smelter-specific slope coefficients, IPCC technology-specific slope coefficients were
10 applied (IPCC 2006). The slope coefficients were combined with smelter-specific anode effect data collected by
11 aluminum companies and reported under the VAIP to estimate emission factors over time. For 1990 through 2009,
12 smelter-specific anode effect data were available for smelters representing between 80 and 100 percent of U.S.
13 primary aluminum production. Where smelter-specific anode effect data were not available, representative values
14 (e.g., previously reported or industry averages) were used.

15 For all smelters, emission factors were multiplied by annual production to estimate annual emissions at the
16 smelter level. For 1990 through 2009, smelter-specific production data were available for smelters representing
17 between 30 and 100 percent of U.S. primary aluminum production. (For the years after 2000, this percentage was
18 near the high end of the range.) Production at non-reporting smelters was estimated by calculating the difference
19 between the production reported under VAIP and the total U.S. production supplied by USGS or USAA, and then
20 allocating this difference to non-reporting smelters in proportion to their production capacity. Emissions were then
21 aggregated across smelters to estimate national emissions.

22 **Low Voltage Anode Effects**

23 LVAE emissions of CF₄ were estimated for 2006 through 2019 based on the Tier 1 (technology-specific, production-
24 based) method in the *2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC
25 2019). Prior to 2006, LVAE emissions are believed to have been negligible.⁶⁸ The following equation was used to
26 estimate LVAE PFC emissions:

$$27 \quad \quad \quad LVAE E_{CF_4} = LVAE EF_{CF_4} \times MP$$

28 where,

29			
30	LVAE E _{CF₄}	=	LVAE emissions of CF ₄ from aluminium production, kg CF ₄
31	LVAE EF _{CF₄}	=	LVAE emission factor for CF ₄ (default by cell technology type)
32	MP	=	metal production by cell technology type, tons Al.
33			

34 LVAE emissions estimates were then combined with HVAE emissions estimates to calculate total PFC emissions
35 from aluminum production.

36 **Production Data**

37 Between 1990 and 2009, production data were provided under the VAIP by 21 of the 23 U.S. smelters that
38 operated during at least part of that period. For the non-reporting smelters, production was estimated based on
39 the difference between reporting smelters and national aluminum production levels (USGS and USAA 1990
40 through 2009), with allocation to specific smelters based on reported production capacities (USGS 1990 through
41 2009).

⁶⁸ The *2019 Refinement* states, “Since 2006, the global aluminium industry has undergone changes in technology and operating conditions that make LVAE emissions much more prevalent¹²; these changes have occurred not only through uptake of newer technologies (e.g., PFPB_I to PFPB_M) but also during upgrades within the same technology in order to maximise productivity and reduce energy use” (IPCC 2019). Footnote #12 uses the example of PFPB_L, which is prevalent in the U.S., as an older technology that has been upgraded.

1 National primary aluminum production data for 2019 were obtained via USAA (USAA 2020). For 1990 through
 2 2001, and 2006 (see Table 4-82) data were obtained from USGS *Mineral Industry Surveys: Aluminum Annual Report*
 3 (USGS 1995, 1998, 2000, 2001, 2002, 2007). For 2002 through 2005, and 2007 through 2019, national aluminum
 4 production data were obtained from the USAA's *Primary Aluminum Statistics* (USAA 2004 through 2006, 2008
 5 through 2020).

6 **Table 4-82: Production of Primary Aluminum (kt)**

Year	kt
1990	4,048
2005	2,478
2015	1,587
2016	818
2017	741
2018	897
2019	1,126

7 Uncertainty and Time-Series Consistency

8 Uncertainty was estimated for the CO₂, CF₄, and C₂F₆ emission values reported by each individual facility to EPA's
 9 GHGRP, taking into consideration the uncertainties associated with aluminum production, anode effect minutes,
 10 and slope factors. The uncertainty bounds used for these parameters were established based on information
 11 collected under the VAIP and held constant through 2019. Uncertainty surrounding the reported CO₂, CF₄, and C₂F₆
 12 emission values were determined to have a normal distribution with uncertainty ranges of ±6, ±16, and ±20
 13 percent, respectively.

14 For the LVAE emission values not reported through EPA's GHGRP but estimated instead through a Tier 1
 15 methodology, the analysis examined uncertainty associated with primary capacity data as well as technology-
 16 specific emission factors. Uncertainty for each facility's primary capacity, reported in the USGS Yearbook, was
 17 estimated to have a Pert Beta distribution with an uncertainty range of -10/+7 percent based on the uncertainty of
 18 reported capacity data, the number of years since the facility reported new capacity data, and uncertainty in
 19 capacity utilization. Uncertainty was applied to LVAE emission factors according to technology using the
 20 uncertainty ranges provided in the *2019 Refinement to the 2006 IPCC Guidelines*. An uncertainty range for
 21 Horizontal Stud Söderberg (HSS) technology was not provided in the *2019 Refinement to the 2006 IPCC Guidelines*
 22 due to insufficient data, so a normal distribution and uncertainty range of ±99 percent was applied for that
 23 technology based on expert judgment. A Monte Carlo analysis was applied to estimate the overall uncertainty of
 24 the CO₂, CF₄, and C₂F₆ emission estimates for the U.S. aluminum industry as a whole, and the results are provided
 25 below.

26 The results of this Approach 2 quantitative uncertainty analysis are summarized in Table 4-83. Aluminum
 27 production-related CO₂ emissions were estimated to be between 1.84 and 1.92 MMT CO₂ Eq. at the 95 percent
 28 confidence level. This indicates a range of approximately 2 percent below to 2 percent above the emission
 29 estimate of 1.88 MMT CO₂ Eq. Also, production-related CF₄ emissions were estimated to be between 1.22 and 1.43
 30 MMT CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 8 percent below to 8
 31 percent above the emission estimate of 1.33 MMT CO₂ Eq. Finally, aluminum production-related C₂F₆ emissions
 32 were estimated to be between 0.31 and 0.41 MMT CO₂ Eq. at the 95 percent confidence level. This indicates a
 33 range of approximately 13 percent below to 14 percent above the emission estimate of 0.36 MMT CO₂ Eq.

34

Table 4-83: Approach 2 Quantitative Uncertainty Estimates for CO₂ and PFC Emissions from Aluminum Production (MMT CO₂ Eq. and Percent)

Source	Gas	2019 Emission Estimate (MMT CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			(MMT CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Aluminum Production	CO ₂	1.88	1.84	1.92	-2%	2%
Aluminum Production	CF ₄	1.40	1.30	1.52	-8%	8%
Aluminum Production	C ₂ F ₆	0.36	0.31	0.41	-14%	14%

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

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

QA/QC and Verification

General quality assurance/quality control (QA/QC) procedures were applied consistent with the U.S. Inventory QA/QC plan, which is in accordance with Volume 1, Chapter 6 of *2006 IPCC Guidelines* as described in the introduction of the IPPU chapter (see Annex 8 for more details). For the GHGRP data, EPA verifies annual facility-level reports through a multi-step process (e.g., including a combination of pre-and post-submittal electronic checks and manual reviews by staff) to identify potential errors and ensure that data submitted to EPA are accurate, complete, and consistent (EPA 2015).⁶⁹ Based on the results of the verification process, EPA follows up with facilities to resolve mistakes that may have occurred. The post-submittals checks are consistent with a number of general and category-specific QC procedures, including: range checks, statistical checks, algorithm checks, and year-to-year checks of reported data and emissions.

Recalculations Discussion

In a few instances, GHGRP-reporting facilities revised their GHGRP reports due to previously identified reporting errors in 2015 and 2018, resulting in a slight decrease in total emissions of PFCs.

Based on the *2019 Refinement*, Low Voltage Anode Effect (LVAE) emissions were estimated for the years 2006 to 2019 using the Tier 1 production-based methodology (IPCC 2019). The Tier 1 LVAE method uses technology-based default emissions factors, multiplied by metal production. Metal production was estimated based on primary aluminum production capacity. The addition of LVAE emissions estimates resulted in slightly higher CF₄ estimates from 2006 through 2019, with LVAE emissions accounting for 5 percent of total CF₄ emissions in 2019.

4.20 Magnesium Production and Processing (CRF Source Category 2C4)

The magnesium metal production and casting industry uses sulfur hexafluoride (SF₆) as a cover gas to prevent the rapid oxidation of molten magnesium in the presence of air. Sulfur hexafluoride has been used in this application around the world for more than thirty years. A dilute gaseous mixture of SF₆ with dry air and/or carbon dioxide (CO₂) is blown over molten magnesium metal to induce and stabilize the formation of a protective crust. A small

⁶⁹ GHGRP Report Verification Factsheet. <https://www.epa.gov/sites/production/files/2015-07/documents/ghgrp_verification_factsheet.pdf>.

1 portion of the SF₆ reacts with the magnesium to form a thin molecular film of mostly magnesium oxide and
 2 magnesium fluoride. The amount of SF₆ reacting in magnesium production and processing is considered to be
 3 negligible and thus all SF₆ used is assumed to be emitted into the atmosphere. Alternative cover gases, such as
 4 AM-cover™ (containing HFC-134a), Novec™ 612 (FK-5-1-12) and dilute sulfur dioxide (SO₂) systems can and are
 5 being used by some facilities in the United States. However, many facilities in the United States are still using
 6 traditional SF₆ cover gas systems.

7 The magnesium industry emitted 1.0 MMT CO₂ Eq. (0.04 kt) of SF₆, 0.1 MMT CO₂ Eq. (0.05 kt) of HFC-134a, and
 8 0.001 MMT CO₂ Eq. (1.4 kt) of CO₂ in 2019. This represents a decrease of approximately 11 percent from total 2018
 9 emissions (see Table 4-84) and a decrease in SF₆ emissions by 11 percent. In 2019, total HFC-134a emissions
 10 decreased from 0.079 MMT CO₂ Eq. to 0.066 MMT CO₂ Eq., or a 16 percent decrease as compared to 2018
 11 emissions. FK 5-1-12 emissions were held constant from 2018. The emissions of the carrier gas, CO₂, decreased
 12 from 1.43 kt in 2018 to 1.35 kt in 2019, or 6 percent.

13 **Table 4-84: SF₆, HFC-134a, FK 5-1-12 and CO₂ Emissions from Magnesium Production and**
 14 **Processing (MMT CO₂ Eq.)**

Year	1990	2005	2015	2016	2017	2018	2019
SF ₆	5.2	2.7	1.0	1.1	1.1	1.1	1.0
HFC-134a	0.0	0.0	0.1	0.1	0.1	0.1	0.1
CO ₂	+	+	+	+	+	+	+
FK 5-1-12 ^a	0.0	0.0	+	+	+	+	+
Total	5.2	2.7	1.1	1.2	1.2	1.2	1.0

+ Does not exceed 0.05 MMT CO₂ Eq.

^a Emissions of FK 5-1-12 are not included in totals.

15 **Table 4-85: SF₆, HFC-134a, FK 5-1-12 and CO₂ Emissions from Magnesium Production and**
 16 **Processing (kt)**

Year	1990	2005	2015	2016	2017	2018	2019
SF ₆	0.2	0.1	+	+	+	+	+
HFC-134a	0.0	0.0	0.1	0.1	0.1	0.1	+
CO ₂	1.4	2.9	2.6	2.7	3.1	1.4	1.4
FK 5-1-12 ^a	0.0	0.0	+	+	+	+	+

+ Does not exceed 0.05 kt

17 Methodology

18 Emission estimates for the magnesium industry incorporate information provided by industry participants in EPA's
 19 SF₆ Emission Reduction Partnership for the Magnesium Industry as well as emissions data reported through
 20 Subpart T (Magnesium Production and Processing) of EPA's GHGRP. The Partnership started in 1999 and, in 2010,
 21 participating companies represented 100 percent of U.S. primary and secondary production and 16 percent of the
 22 casting sector production (i.e., die, sand, permanent mold, wrought, and anode casting). SF₆ emissions for 1999
 23 through 2010 from primary production, secondary production (i.e., recycling), and die casting were generally
 24 reported by Partnership participants. Partners reported their SF₆ consumption, which is assumed to be equivalent
 25 to emissions. Along with SF₆, some Partners reported their HFC-134a and FK 5-1-12 consumed, which is also
 26 assumed to be equal to emissions. The last reporting year under the Partnership was 2010. Emissions data for
 27 2011 through 2019 are obtained through EPA's GHGRP. Under the program, owners or operators of facilities that
 28 have a magnesium production or casting process must report emissions from use of cover or carrier gases, which
 29 include SF₆, HFC-134a, FK 5-1-12 and CO₂. Consequently, cover and carrier gas emissions from magnesium
 30 production and processing were estimated for three time periods, depending on the source of the emissions data:
 31 1990 through 1998 (pre-EPA Partnership), 1999 through 2010 (EPA Partnership), and 2011 through 2019 (EPA
 32 GHGRP). The methodologies described below also make use of magnesium production data published by the U.S.
 33 Geological Survey (USGS) as available.

1 **1990 through 1998**

2 To estimate emissions for 1990 through 1998, industry SF₆ emission factors were multiplied by the corresponding
3 metal production and consumption (casting) statistics from USGS. For this period, it was assumed that there was
4 no use of HFC-134a or FK 5-1-12 cover gases, and hence emissions were not estimated for these alternatives.

5 Sulfur hexafluoride emission factors from 1990 through 1998 were based on a number of sources and
6 assumptions. Emission factors for primary production were available from U.S. primary producers for 1994 and
7 1995. The primary production emission factors were 1.2 kg SF₆ per metric ton for 1990 through 1993, and 1.1 kg
8 SF₆ per metric ton for 1994 through 1997. The emission factor for secondary production from 1990 through 1998
9 was assumed to be constant at the 1999 average Partner value. An emission factor for die casting of 4.1 kg SF₆ per
10 metric ton, which was available for the mid-1990s from an international survey (Gjestland and Magers 1996), was
11 used for years 1990 through 1996. For 1996 through 1998, the emission factor for die casting was assumed to
12 decline linearly to the level estimated based on Partner reports in 1999. This assumption is consistent with the
13 trend in SF₆ sales to the magnesium sector that was reported in the RAND survey of major SF₆ manufacturers,
14 which showed a decline of 70 percent from 1996 to 1999 (RAND 2002). Sand casting emission factors for 1990
15 through 2001 were assumed to be the same as the 2002 emission factor. The emission factors for the other
16 processes (i.e., permanent mold, wrought, and anode casting), about which less is known, were assumed to remain
17 constant at levels defined in Table 4-84. The emission factors for the other processes (i.e., permanent mold,
18 wrought, and anode casting) were based on discussions with industry representatives.

19 The quantities of CO₂ carrier gas used for each production type have been estimated using the 1999 estimated CO₂
20 emissions data and the annual calculated rate of change of SF₆ use in the 1990 through 1999 time period. For each
21 year and production type, the rate of change of SF₆ use between the current year and the subsequent year was
22 first estimated. This rate of change was then applied to the CO₂ emissions of the subsequent year to determine the
23 CO₂ emission of the current year. The emissions of carrier gases for permanent mold, wrought, and anode
24 processes are not estimated in this Inventory.

25 **1999 through 2010**

26 The 1999 through 2010 emissions from primary and secondary production are based on information provided by
27 EPA's industry Partners. In some instances, there were years of missing Partner data, including SF₆ consumption
28 and metal processed. For these situations, emissions were estimated through interpolation where possible, or by
29 holding company-reported emissions (as well as production) constant from the previous year. For alternative cover
30 gases, including HFC-134a and FK 5-1-12, mainly reported data was relied upon. That is, unless a Partner reported
31 using an alternative cover gas, it was not assumed it was used. Emissions of alternate gases were also estimated
32 through linear interpolation where possible.

33 The die casting emission estimates for 1999 through 2010 were also based on information supplied by industry
34 Partners. When a Partner was determined to be no longer in production, its metal production and usage rates
35 were set to zero. Missing data on emissions or metal input was either interpolated or held constant at the last
36 available reported value. In 1999 through 2010, Partners were assumed to account for all die casting tracked by
37 USGS. For 1999, die casters who were not Partners were assumed to be similar to Partners who cast small parts.
38 Due to process requirements, these casters consume larger quantities of SF₆ per metric ton of processed
39 magnesium than casters that process large parts. Consequently, emission estimates from this group of die casters
40 were developed using an average emission factor of 5.2 kg SF₆ per metric ton of magnesium. This emission factor
41 was developed using magnesium production and SF₆ usage data for the year 1999. In 2008, the derived emission
42 factor for die casting began to increase after many years of largely decreasing emission factors. As determined
43 through an analysis of activity data reported from the USGS, this increase is due to a temporary decrease in
44 production at many facilities between 2008 and 2010, which reflects the change in production that occurred
45 during the recession.

46 The emissions from other casting operations were estimated by multiplying emission factors (kg SF₆ per metric ton
47 of metal produced or processed) by the amount of metal produced or consumed from USGS, with the exception of
48 some years for which Partner sand casting emissions data are available. The emission factors for sand casting

1 activities were acquired through the data reported by the Partnership for 2002 to 2006. For 1999-2001, the sand
 2 casting emission factor was held constant at the 2002 Partner-reported level. For 2007 through 2010, the sand
 3 casting Partner did not report and the reported emission factor from 2005 was applied to the Partner and to all
 4 other sand casters. Activity data for 2005 was obtained from USGS (USGS 2005b).

5 The emission factors for primary production, secondary production and sand casting for the 1999 to 2010 are not
 6 published to protect company-specific production information. However, the emission factor for primary
 7 production has not risen above the average 1995 Partner value of 1.1 kg SF₆ per metric ton. The emission factors
 8 for the other industry sectors (i.e., permanent mold, wrought, and anode casting) were based on discussions with
 9 industry representatives. The emission factors for casting activities are provided below in Table 4-86.

10 The emissions of HFC-134a and FK-5-1-12 were included in the estimates for only instances where Partners
 11 reported that information to the Partnership. Emissions of these alternative cover gases were not estimated for
 12 instances where emissions were not reported.

13 Carbon dioxide carrier gas emissions were estimated using the emission factors developed based on GHGRP-
 14 reported carrier gas and cover gas data, by production type. It was assumed that the use of carrier gas, by
 15 production type, is proportional to the use of cover gases. Therefore, an emission factor, in kg CO₂ per kg cover gas
 16 and weighted by the cover gases used, was developed for each of the production types. GHGRP data on which
 17 these emissions factors are based was available for primary, secondary, die casting and sand casting. The emission
 18 factors were applied to the total quantity of all cover gases used (SF₆, HFC-134a, and FK-5-1-12) by production type
 19 in this time period. Carrier gas emissions for the 1999 through 2010 time period were only estimated for those
 20 Partner companies that reported using CO₂ as a carrier gas through the GHGRP. Using this approach helped ensure
 21 time-series consistency. The emissions of carrier gases for permanent mold, wrought, and anode processes are not
 22 estimated in this Inventory.

23 **Table 4-86: SF₆ Emission Factors (kg SF₆ per metric ton of magnesium)**

Year	Die Casting ^a	Permanent Mold	Wrought	Anodes
1999	1.75 ^b	2	1	1
2000	0.72	2	1	1
2001	0.72	2	1	1
2002	0.71	2	1	1
2003	0.81	2	1	1
2004	0.79	2	1	1
2005	0.77	2	1	1
2006	0.88	2	1	1
2007	0.64	2	1	1
2008	0.97	2	1	1
2009	1.41	2	1	1
2010	1.43	2	1	1

^a Weighted average includes all die casters, Partners and non-Partners. For the majority of the time series (2000 through 2010), Partners made up 100 percent of die casters in the United States.

^b Weighted average that includes an estimated emission factor of 5.2 kg SF₆ per metric ton of magnesium for die casters that do not participate in the Partnership.

24 **2011 through 2019**

25 For 2011 through 2019, for the primary and secondary producers, GHGRP-reported cover and carrier gases
 26 emissions data were used. For sand and die casting, some emissions data was obtained through EPA's GHGRP.
 27 Additionally, in 2018 a new GHGRP reporter began reporting permanent mold emissions. The balance of the
 28 emissions for this industry segment was estimated based on previous Partner reporting (i.e., for Partners that did
 29 not report emissions through EPA's GHGRP) or were estimated by multiplying emission factors by the amount of
 30 metal produced or consumed. Partners who did not report through EPA's GHGRP were assumed to have continued

1 to emit SF₆ at the last reported level, which was from 2010 in most cases, unless publicly available sources
2 indicated that these facilities have closed or otherwise eliminated SF₆ emissions from magnesium production (ARB
3 2015). Many Partners that did report through the GHGRP showed increases in SF₆ emissions driven by increased
4 production related to a continued economic recovery after the 2008 recession. One Partner in particular reported
5 an anonymously large increase in SF₆ emissions from 2010-2011, further driving increases in emissions between
6 the two time periods of inventory estimates. All Partners were assumed to have continued to consume magnesium
7 at the last reported level. Where the total metal consumption estimated for the Partners fell below the U.S. total
8 reported by USGS, the difference was multiplied by the emission factors discussed in the section above, i.e., non-
9 partner emission factors. For the other types of production and processing (i.e., permanent mold, wrought, and
10 anode casting), emissions were estimated by multiplying the industry emission factors with the metal production
11 or consumption statistics obtained from USGS (USGS 2020). USGS data for 2019 was not yet available at the time
12 of the analysis, so the 2017 values were held constant through 2019 as a proxy. Where data was submitted late or
13 with errors or not available for 2019 through the GHGRP, EPA held values constant at previous year's levels for
14 emissions.

15 **Uncertainty and Time-Series Consistency**

16 Uncertainty surrounding the total estimated emissions in 2019 is attributed to the uncertainties around SF₆, HFC-
17 134a, and CO₂ emission estimates. To estimate the uncertainty surrounding the estimated 2019 SF₆ emissions from
18 magnesium production and processing, the uncertainties associated with three variables were estimated: (1)
19 emissions reported by magnesium producers and processors for 2019 through EPA's GHGRP, (2) emissions
20 estimated for magnesium producers and processors that reported via the Partnership in prior years but did not
21 report 2019 emissions through EPA's GHGRP, and (3) emissions estimated for magnesium producers and
22 processors that did not participate in the Partnership or report through EPA's GHGRP. An uncertainty of 5 percent
23 was assigned to the emissions (usage) data reported by each GHGRP reporter for all the cover and carrier gases
24 (per the *2006 IPCC Guidelines*). If facilities did not report emissions data during the current reporting year through
25 EPA's GHGRP, SF₆ emissions data were held constant at the most recent available value reported through the
26 Partnership. The uncertainty associated with these values was estimated to be 30 percent for each year of
27 extrapolation. The uncertainty of the total inventory estimate remained relatively constant between 2018 and
28 2019.

29 Alternate cover gas and carrier gases data was set equal to zero if the facilities did not report via the GHGRP. For
30 those industry processes that are not represented in the Partnership, such as permanent mold and wrought
31 casting, SF₆ emissions were estimated using production and consumption statistics reported by USGS and
32 estimated process-specific emission factors (see Table 4-87). The uncertainties associated with the emission
33 factors and USGS-reported statistics were assumed to be 75 percent and 25 percent, respectively. Emissions
34 associated with die casting and sand casting activities utilized emission factors based on Partner reported data
35 with an uncertainty of 75 percent. In general, where precise quantitative information was not available on the
36 uncertainty of a parameter, a conservative (upper-bound) value was used.

37 Additional uncertainties exist in these estimates that are not addressed in this methodology, such as the basic
38 assumption that SF₆ neither reacts nor decomposes during use. The melt surface reactions and high temperatures
39 associated with molten magnesium could potentially cause some gas degradation. Previous measurement studies
40 have identified SF₆ cover gas degradation in die casting applications on the order of 20 percent (Bartos et al. 2007).
41 Sulfur hexafluoride may also be used as a cover gas for the casting of molten aluminum with high magnesium
42 content; however, the extent to which this technique is used in the United States is unknown.

43 The results of this Approach 2 quantitative uncertainty analysis are summarized in Table 4-87. Total emissions
44 associated with magnesium production and processing were estimated to be between 0.95 and 1.12 MMT CO₂ Eq.
45 at the 95 percent confidence level. This indicates a range of approximately 8 percent below to 8 percent above the
46 2019 emission estimate of 1.03 MMT CO₂ Eq. The uncertainty estimates for 2019 are similar to the uncertainty
47 reported for 2018 in the previous Inventory.

1 **Table 4-87: Approach 2 Quantitative Uncertainty Estimates for SF₆, HFC-134a and CO₂**
 2 **Emissions from Magnesium Production and Processing (MMT CO₂ Eq. and Percent)**

Source	Gas	2019 Emission Estimate (MMT CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			(MMT CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Magnesium Production	SF ₆ , HFC- 134a, CO ₂	1.03	0.95	1.12	-8%	8%

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

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

6 QA/QC and Verification

7 For the GHGRP data, EPA verifies annual facility-level reports through a multi-step process (e.g., including a
 8 combination of pre-and post-submittal electronic checks and manual reviews by staff) to identify potential errors
 9 and ensure that data submitted to EPA are accurate, complete, and consistent (EPA 2015).⁷⁰ Based on the results
 10 of the verification process, EPA follows up with facilities to resolve mistakes that may have occurred. The post-
 11 submittals checks are consistent with a number of general and category-specific QC procedures, including: range
 12 checks, statistical checks, algorithm checks, and year-to-year checks of reported data and emissions.

13 For more information on the general QA/QC process applied to this source category, consistent with Volume 1,
 14 Chapter 6 of the *2006 IPCC Guidelines*, see the QA/QC and Verification Procedures section in the introduction of
 15 the IPPU chapter and Annex 8 for more details.

16 Recalculations Discussion

17 Die casting and sand volumes were updated based on the release of the 2017 USGS Minerals Yearbook (USGS
 18 2017). Additionally, one facility's emissions were revised for 2017 and 2018 to reflect its confirmed closure. These
 19 revisions resulted in slightly higher emissions in 2017 and reduced emissions in 2018. Throughout the time series,
 20 these changes resulted in an average increase in emissions of .001 MMT CO₂ Eq. (1.4 percent) for HFCs and a .001
 21 MMT CO₂ Eq. (0.1 percent) for SF₆.

22 Planned Improvements

23 Cover gas research conducted over the last decade has found that SF₆ used for magnesium melt protection can
 24 have degradation rates on the order of 20 percent in die casting applications (Bartos et al. 2007). Current emission
 25 estimates assume (per the *2006 IPCC Guidelines*) that all SF₆ utilized is emitted to the atmosphere. Additional
 26 research may lead to a revision of the *2006 IPCC Guidelines* to reflect this phenomenon and until such time,
 27 developments in this sector will be monitored for possible application to the Inventory methodology. Usage and
 28 emission details of carrier gases in permanent mold, wrought, and anode processes will be researched as part of a
 29 future Inventory. Based on this research and data from a permanent mold facility newly reporting the GHGRP, it
 30 will be determined if CO₂ carrier gas emissions are to be estimated.

⁷⁰ GHGRP Report Verification Factsheet. <https://www.epa.gov/sites/production/files/2015-07/documents/ghgrp_verification_factsheet.pdf>.

1 Additional emissions are generated as byproducts from the use of alternate cover gases, which are not currently
2 accounted for. Research on this topic is developing, and as reliable emission factors become available, these
3 emissions will be incorporated into the Inventory.

4 4.21 Lead Production (CRF Source Category 5 2C5)

6 In 2019, lead was produced in the United States only using secondary production processes. Until 2014, lead
7 production in the United States involved both primary and secondary processes—both of which emit carbon
8 dioxide (CO₂) (Sjardin 2003). Emissions from fuels consumed for energy purposes during the production of lead are
9 accounted for in the Energy chapter.

10 Primary production of lead through the direct smelting of lead concentrate produces CO₂ emissions as the lead
11 concentrates are reduced in a furnace using metallurgical coke (Sjardin 2003). Primary lead production, in the form
12 of direct smelting, previously occurred at a single smelter in Missouri. This primary lead smelter was closed at the
13 end of 2013. In 2014, the smelter processed a small amount of residual lead during demolition of the site (USGS
14 2015), and in 2018, the smelter processed no lead (USGS 2016, 2019).

15 Similar to primary lead production, CO₂ emissions from secondary lead production result when a reducing agent,
16 usually metallurgical coke, is added to the smelter to aid in the reduction process. Carbon dioxide emissions from
17 secondary production also occur through the treatment of secondary raw materials (Sjardin 2003). Secondary
18 production primarily involves the recycling of lead acid batteries and post-consumer scrap at secondary smelters.
19 Secondary lead production has increased in the United States over the past decade, while primary lead production
20 has decreased to production levels of zero. In 2019, secondary lead production accounted for 100 percent of total
21 lead production. The lead-acid battery industry accounted for more than 93 percent of the reported U.S. lead
22 consumption in 2019 (USGS 2020).

23 In 2019, total secondary lead production in the United States increased from 2018. The United States has become
24 more reliant on imported refined lead in recent years, owing to the closure of the last primary lead smelter in
25 2013. Exports of spent SLI batteries have been generally decreasing since 2014, however they have increased back
26 up to the 2014 level for 2019 (USGS 2015 through 2020). In the first 10 months of 2019, 22.9 million spent SLI lead-
27 acid batteries were exported, essentially unchanged compared with that in the same time period in 2018 (USGS
28 2020).

29 As in 2018, U.S. primary lead production remained at production levels of zero for 2019. This is due to the closure
30 of the only domestic primary lead smelter in 2013 (year-end), as stated previously. In 2019, U.S. secondary lead
31 production was greater than 2018 levels and has increased by 30 percent since 1990 (USGS 1995 through 2020).

32 In 2019, U.S. lead production totaled 1,200,000 metric tons (USGS 2020). The resulting emissions of CO₂ from 2019
33 lead production were estimated to be 0.5 MMT CO₂ Eq. (540 kt) (see Table 4-88).

34 The United States was the fourth largest mine producer of lead in the world, behind China, Australia, and Peru, and
35 accounted for approximately 6 percent of world production in 2019 (USGS 2020).

36 **Table 4-88: CO₂ Emissions from Lead Production (MMT CO₂ Eq. and kt)**

Year	MMT CO ₂ Eq.	Kt
1990	0.5	516
2005	0.6	553
2015	0.5	473
2016	0.5	500

2017	0.5	513
2018	0.5	513
2019	0.5	540

1 After a steady increase in total emissions from 1995 to 2000, total emissions have gradually decreased since 2000,
 2 slightly increased since 2015, and are currently 5 percent higher than 1990 levels.

3 Methodology

4 The methods used to estimate emissions for lead production⁷¹ are based on Sjardin’s work (Sjardin 2003) for lead
 5 production emissions and Tier 1 methods from the 2006 IPCC Guidelines. The Tier 1 equation is as follows:

$$6 \quad CO_2 \text{ Emissions} = (DS \times EF_{DS}) + (S \times EF_S)$$

7 where,

- 8 DS = Lead produced by direct smelting, metric ton
- 9 S = Lead produced from secondary materials
- 10 EF_{DS} = Emission factor for direct Smelting, metric tons CO₂/metric ton lead product
- 11 EF_S = Emission factor for secondary materials, metric tons CO₂/metric ton lead product

12 For primary lead production using direct smelting, Sjardin (2003) and the IPCC (2006) provide an emission factor of
 13 0.25 metric tons CO₂/metric ton lead. For secondary lead production, Sjardin (2003) and IPCC (2006) provide an
 14 emission factor of 0.25 metric tons CO₂/metric ton lead for direct smelting, as well as an emission factor of 0.2
 15 metric tons CO₂/metric ton lead produced for the treatment of secondary raw materials (i.e., pretreatment of lead
 16 acid batteries). Since the secondary production of lead involves both the use of the direct smelting process and the
 17 treatment of secondary raw materials, Sjardin recommends an additive emission factor to be used in conjunction
 18 with the secondary lead production quantity. The direct smelting factor (0.25) and the sum of the direct smelting
 19 and pretreatment emission factors (0.45) are multiplied by total U.S. primary and secondary lead production,
 20 respectively, to estimate CO₂ emissions.

21 The production and use of coking coal for lead production is adjusted for within the Energy chapter as this fuel was
 22 consumed during non-energy related activities. Additional information on the adjustments made within the Energy
 23 sector for Non-Energy Use of Fuels is described in both the Methodology section of CO₂ from Fossil Fuel
 24 Combustion (3.1 Fossil Fuel Combustion (CRF Source Category 1A)) and Annex 2.1, Methodology for Estimating
 25 Emissions of CO₂ from Fossil Fuel Combustion.

26 The 1990 through 2019 activity data for primary and secondary lead production (see Table 4-89) were obtained
 27 from the U.S. Geological Survey (USGS 1995 through 2020).

⁷¹ EPA has not integrated aggregated facility-level Greenhouse Gas Reporting Program (GHGRP) information to inform these estimates. The aggregated information (e.g., activity data and emissions) associated with Lead Production did not meet criteria to shield underlying confidential business information (CBI) from public disclosure.

1 **Table 4-89: Lead Production (Metric Tons)**

Year	Primary	Secondary
1990	404,000	922,000
2005	143,000	1,150,000
2015	0	1,050,000
2016	0	1,110,000
2017	0	1,140,000
2018	0	1,140,000
2019	0	1,200,000

2 **Uncertainty and Time-Series Consistency – TO BE UPDATED**

3 Uncertainty associated with lead production relates to the emission factors and activity data used. The direct
 4 smelting emission factor used in primary production is taken from Sjardin (2003) who averaged the values
 5 provided by three other studies (Dutrizac et al. 2000; Morris et al. 1983; Ullman 1997). For secondary production,
 6 Sjardin (2003) added a CO₂ emission factor associated with battery treatment. The applicability of these emission
 7 factors to plants in the United States is uncertain. There is also a smaller level of uncertainty associated with the
 8 accuracy of primary and secondary production data provided by the USGS which is collected via voluntary surveys;
 9 the uncertainty of the activity data is a function of the reliability of reported plant-level production data and the
 10 completeness of the survey response.

11 The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-90. Lead production CO₂
 12 emissions in 2018 were estimated to be between 0.4 and 0.6 MMT CO₂ Eq. at the 95 percent confidence level. This
 13 indicates a range of approximately 15 percent below and 15 percent above the emission estimate of 0.5 MMT CO₂
 14 Eq.

15 **Table 4-90: Approach 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Lead
 16 Production (MMT CO₂ Eq. and Percent)**

Source	Gas	2018 Emission Estimate (MMT CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Lead Production	CO ₂	0.5	0.4	0.6	-15%	+15%

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

17 Methodological approaches discussed below were applied to applicable years to ensure time-series consistency in
 18 emissions from 1990 through 2018. Details on the emission trends through time are described in more detail in the
 19 Methodology section, above.

20 **QA/QC and Verification**

21 For more information on the general QA/QC process applied to this source category, consistent with Volume 1,
 22 Chapter 6 of the *2006 IPCC Guidelines*, see the QA/QC and Verification Procedures section in the introduction of
 23 the IPPU chapter.

24 Initial review of activity data show that EPA’s GHGRP Subpart R lead production data and resulting emissions are
 25 fairly consistent with those reported by USGS. EPA is still reviewing available GHGRP data, reviewing QC analysis to
 26 understand differences in data reporting (i.e., threshold implications), and assessing the possibility of including this
 27 planned improvement in future inventory reports (see Planned Improvements section below). Currently, GHGRP
 28 data are used for QA purposes only.

Recalculations Discussion

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

Planned Improvements

Pending resources and prioritization of improvements for more significant sources, EPA will continue to evaluate and analyze data reported under EPA's GHGRP that would be useful to improve the emission estimates and category-specific QC for the Lead Production source category, in particular considering completeness of reported lead production given the reporting threshold. Particular attention will be made to ensuring time-series consistency of the emissions estimates presented in future Inventory reports, consistent with IPCC and UNFCCC guidelines. This is required as the facility-level reporting data from EPA's GHGRP, with the program's initial requirements for reporting of emissions in calendar year 2010, are not available for all inventory years (i.e., 1990 through 2009) as required for this Inventory. 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.⁷²

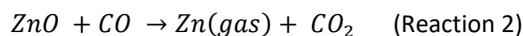
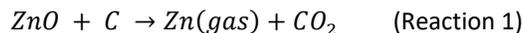
4.22 Zinc Production (CRF Source Category 2C6)

Zinc production in the United States consists of both primary and secondary processes. Of the primary and secondary processes used in the United States, only the electrothermic and Waelz kiln secondary processes result in non-energy carbon dioxide (CO₂) emissions (Viklund-White 2000). Emissions from fuels consumed for energy purposes during the production of zinc are accounted for in the Energy chapter.

The majority of zinc produced in the United States is used for galvanizing. Galvanizing is a process where zinc coating is applied to steel in order to prevent corrosion. Zinc is used extensively for galvanizing operations in the automotive and construction industry. Zinc is also used in the production of zinc alloys and brass and bronze alloys (e.g., brass mills, copper foundries, and copper ingot manufacturing). Zinc compounds and dust are also used, to a lesser extent, by the agriculture, chemicals, paint, and rubber industries.

Primary production in the United States is conducted through the electrolytic process, while secondary techniques include the electrothermic and Waelz kiln processes, as well as a range of other metallurgical, hydrometallurgical, and pyrometallurgical processes. Worldwide primary zinc production also employs a pyrometallurgical process using the Imperial Smelting Furnace process; however, this process is not used in the United States (Sjardin 2003).

In the electrothermic process, roasted zinc concentrate and secondary zinc products enter a sinter feed where they are burned to remove impurities before entering an electric retort furnace. Metallurgical coke is added to the electric retort furnace as a carbon-containing reductant. This concentration step, using metallurgical coke and high temperatures, reduces the zinc oxides and produces vaporized zinc, which is then captured in a vacuum condenser. This reduction process also generates non-energy CO₂ emissions.



⁷² See <http://www.ipcc-nggip.iges.or.jp/public/tb/TFI_Technical_Bulletin_1.pdf>.

1 In the Waelz kiln process, electric arc furnace (EAF) dust, which is captured during the recycling of galvanized steel,
 2 enters a kiln along with a reducing agent (typically carbon-containing metallurgical coke). When kiln temperatures
 3 reach approximately 1,100 to 1,200 degrees Celsius, zinc fumes are produced, which are combusted with air
 4 entering the kiln. This combustion forms zinc oxide, which is collected in a baghouse or electrostatic precipitator,
 5 and is then leached to remove chloride and fluoride. The use of carbon-containing metallurgical coke in a high-
 6 temperature fuming process results in non-energy CO₂ emissions. Through this process, approximately 0.33 metric
 7 tons of zinc is produced for every metric ton of EAF dust treated (Viklund-White 2000).

8 The only companies in the United States that use emissive technology to produce secondary zinc products are
 9 American Zinc Recycling (AZR) (formerly “Horsehead Corporation”), PIZO, and Steel Dust Recycling (SDR). For AZR,
 10 EAF dust is recycled in Waelz kilns at their Calumet, IL; Palmerton, PA; Rockwood, TN; and Barnwell, SC facilities.
 11 These Waelz kiln facilities produce intermediate zinc products (crude zinc oxide or calcine), most of which was
 12 transported to their Monaca, PA facility where the products were smelted into refined zinc using electrothermic
 13 technology. In April 2014, AZR permanently shut down their Monaca smelter. This was replaced by their new
 14 facility in Mooresboro, NC. The new Mooresboro facility uses a hydrometallurgical process (i.e., solvent extraction
 15 with electrowinning technology) to produce zinc products. The current capacity of the new facility is 155,000 short
 16 tons. Production at the Mooresboro facility was idled in April 2016 and re-started in February 2020, with plans to
 17 be at full capacity by 2021 (Recycling Today 2020). Direct consumption of coal, coke, and natural gas have been
 18 replaced with electricity consumption at the new Mooresboro facility. The new facility is reported to have a
 19 significantly lower greenhouse gas and other air emissions than the Monaca smelter (Horsehead 2012b).

20 The Mooresboro facility uses leaching and solvent extraction (SX) technology combined with electrowinning,
 21 melting, and casting technology. In this process, Waelz Oxide (WOX) is first washed in water to remove soluble
 22 elements such as chlorine, potassium, and sodium, and then is leached in a sulfuric acid solution to dissolve the
 23 contained zinc creating a pregnant liquor solution (PLS). The PLS is then processed in a solvent extraction step in
 24 which zinc is selectively extracted from the PLS using an organic solvent creating a purified zinc-loaded electrolyte
 25 solution. The loaded electrolyte solution is then fed into the electrowinning process in which electrical energy is
 26 applied across a series of anodes and cathodes submerged in the electrolyte solution causing the zinc to deposit on
 27 the surfaces of the cathodes. As the zinc metal builds up on these surfaces, the cathodes are periodically harvested
 28 in order to strip the zinc from their surfaces (Horsehead 2015). Hydrometallurgical production processes are
 29 assumed to be non-emissive since no carbon is used in these processes (Sjardin 2003).

30 PIZO and SDR recycle EAF dust into intermediate zinc products using Waelz kilns, and then sell the intermediate
 31 products to companies who smelt it into refined products.

32 Emissions of CO₂ from zinc production in 2019 were estimated to be 1.0 MMT CO₂ Eq. (964 kt CO₂) (see Table
 33 4-91). All 2019 CO₂ emissions resulted from secondary zinc production processes. Emissions from zinc production
 34 in the United States have increased overall since 1990 due to a gradual shift from non-emissive primary production
 35 to emissive secondary production. In 2019, emissions were estimated to be 60 percent higher than they were in
 36 1990.

37 **Table 4-91: CO₂ Emissions from Zinc Production (MMT CO₂ Eq. and kt)**

Year	MMT CO ₂ Eq.	kt
1990	0.6	632
2005	1.0	1,030
2015	0.9	933
2016	0.9	882
2017	1.0	951
2018	1.0	982
2019	1.0	964

38 In 2019, United States primary and secondary refined zinc production were estimated to total 120,000 metric tons
 39 (USGS 2020) (see Table 4-92). Domestic zinc mine production decreased in 2019, owing partially to the closure of
 40 the Pend Oreille Mine in Washington State in July after current reserves were exhausted. The mine was reopened

1 in December 2014 after being closed since 2009 (USGS 2020). Refined zinc production increased to a 5-year high of
 2 950,000 tons in 2019 (USGS 2020). Primary zinc production (primary slab zinc) in 2018 is used as a proxy for 2019,
 3 while secondary zinc production in 2019 increased by 27 percent compared to 2018.

4 **Table 4-92: Zinc Production (Metric Tons)**

Year	Primary	Secondary	Total
1990	262,704	95,708	358,412
2005	191,120	156,000	347,120
2015	122,857	49,143	172,000
2016	111,000	15,000	126,000
2017	117,000	15,000	132,000
2018	101,000	15,000	116,000
2019	101,000	19,000	120,000

5 Methodology

6 The methods used to estimate non-energy CO₂ emissions from zinc production²⁵¹ using the electrothermic primary
 7 production and Waelz kiln secondary production processes are based on Tier 1 methods from the *2006 IPCC*
 8 *Guidelines* (IPCC 2006). The Tier 1 equation used to estimate emissions from zinc production is as follows:

$$9 \quad E_{CO_2} = Zn \times EF_{default}$$

10 where,

11 E_{CO_2} = CO₂ emissions from zinc production, metric tons
 12 Zn = Quantity of zinc produced, metric tons
 13 $EF_{default}$ = Default emission factor, metric tons CO₂/metric ton zinc produced

14
 15 The Tier 1 emission factors provided by IPCC for Waelz kiln-based secondary production were derived from
 16 metallurgical coke consumption factors and other data presented in Viklund-White (2000). These coke
 17 consumption factors as well as other inputs used to develop the Waelz kiln emission factors are shown below. IPCC
 18 does not provide an emission factor for electrothermic processes due to limited information; therefore, the Waelz
 19 kiln-specific emission factors were also applied to zinc produced from electrothermic processes. Starting in 2014,
 20 refined zinc produced in the United States used hydrometallurgical processes and is assumed to be non-emissive.

21 For Waelz kiln-based production, IPCC recommends the use of emission factors based on EAF dust consumption, if
 22 possible, rather than the amount of zinc produced since the amount of reduction materials used is more directly
 23 dependent on the amount of EAF dust consumed. Since only a portion of emissive zinc production facilities
 24 consume EAF dust, the emission factor based on zinc production is applied to the non-EAF dust consuming facilities
 25 while the emission factor based on EAF dust consumption is applied to EAF dust consuming facilities.

26 The Waelz kiln emission factor based on the amount of zinc produced was developed based on the amount of
 27 metallurgical coke consumed for non-energy purposes per ton of zinc produced (i.e., 1.19 metric tons coke/metric
 28 ton zinc produced) (Viklund-White 2000), and the following equation:

²⁵¹ EPA has not integrated aggregated facility-level Greenhouse Gas Reporting Program (GHGRP) information to inform these estimates. The aggregated information (e.g., activity data and emissions) associated with Zinc Production did not meet criteria to shield underlying confidential business information (CBI) from public disclosure.

$$EF_{Waelz\ Kiln} = \frac{1.19 \text{ metric tons coke}}{\text{metric tons zinc}} \times \frac{0.85 \text{ metric tons C}}{\text{metric tons coke}} \times \frac{3.67 \text{ metric tons CO}_2}{\text{metric tons C}} = \frac{3.70 \text{ metric tons CO}_2}{\text{metric tons zinc}}$$

The Waelz kiln emission factor based on the amount of EAF dust consumed was developed based on the amount of metallurgical coke consumed per ton of EAF dust consumed (i.e., 0.4 metric tons coke/metric ton EAF dust consumed) (Viklund-White 2000), and the following equation:

$$EF_{EAF\ Dust} = \frac{0.4 \text{ metric tons coke}}{\text{metric tons EAF Dust}} \times \frac{0.85 \text{ metric tons C}}{\text{metric tons coke}} \times \frac{3.67 \text{ metric tons CO}_2}{\text{metric tons C}} = \frac{1.24 \text{ metric tons CO}_2}{\text{metric tons EAF Dust}}$$

The total amount of EAF dust consumed by AZR at their Waelz kilns was available from AZR (formerly “Horsehead Corporation”) financial reports for years 2006 through 2015 (Horsehead 2007, 2008, 2010a, 2011, 2012a, 2013, 2014, 2015, and 2016) and from AZR for 2016, 2017, 2018, and 2019 (AZR 2020). Consumption levels for 1990 through 2005 were extrapolated using the percentage change in annual refined zinc production at secondary smelters in the United States, as provided by the U.S. Geological Survey (USGS) *Minerals Yearbook: Zinc* (USGS 1995 through 2006). The EAF dust consumption values for each year were then multiplied by the 1.24 metric tons CO₂/metric ton EAF dust consumed emission factor to develop CO₂ emission estimates for AZR’s Waelz kiln facilities.

The amount of EAF dust consumed by SDR and their total production capacity were obtained from SDR’s facility in Alabama for the years 2011 through 2017 (SDR 2012, 2014, 2015, and 2017). SDR data for 2018 and 2019 were not available at time of Public Review so 2017 data was used as a proxy. SDR’s facility in Alabama underwent expansion in 2011 to include a second unit (operational since early- to mid-2012) and expanded its capacity in 2017 (SDR 2018). SDR’s facility has been operational since 2008. Annual consumption data for SDR was not publicly available for the years 2008, 2009, and 2010. These data were estimated using data for AZR’s Waelz kilns for 2008 through 2010 (Horsehead 2007, 2008, 2010a, 2010b, and 2011). Annual capacity utilization ratios were calculated using AZR’s annual consumption and total capacity for the years 2008 through 2010. AZR’s annual capacity utilization ratios were multiplied with SDR’s total capacity to estimate SDR’s consumption for each of the years, 2008 through 2010 (SDR 2013).

PIZO Technologies Worldwide LLC’s facility in Arkansas has been operational since 2009. The amount of EAF dust consumed by PIZO’s facility for 2009 through 2019 was not publicly available. EAF dust consumption for PIZO’s facility for 2009 and 2010 were estimated by calculating annual capacity utilization of AZR’s Waelz kilns and multiplying this utilization ratio by PIZO’s total capacity (PIZO 2012). EAF dust consumption for PIZO’s facility for 2011 through 2019 were estimated by applying the average annual capacity utilization rates for AZR and SDR (Grupo PROMAX) to PIZO’s annual capacity (Horsehead 2012, 2013, 2014, 2015, and 2016; SDR 2012, 2014 and 2017; PIZO 2012, 2014 and 2017). The 1.24 metric tons CO₂/metric ton EAF dust consumed emission factor was then applied to PIZO’s and SDR’s estimated EAF dust consumption to develop CO₂ emission estimates for those Waelz kiln facilities.

Refined zinc production levels for AZR’s Monaca, PA facility (utilizing electrothermic technology) were available from the company for years 2005 through 2013 (Horsehead 2008, 2011, 2012, 2013, and 2014). The Monaca facility was permanently shut down in April 2014 and was replaced by AZR’s new facility in Mooresboro, NC. The new facility uses hydrometallurgical process to produce refined zinc products. This process is assumed to be non-emissive. Production levels for 1990 through 2004 were extrapolated using the percentage changes in annual refined zinc production at secondary smelters in the United States as provided by USGS *Minerals Yearbook: Zinc* (USGS 1995 through 2005). The 3.70 metric tons CO₂/metric ton zinc emission factor was then applied to the Monaca facility’s production levels to estimate CO₂ emissions for the facility. The Waelz kiln production emission factor was applied in this case rather than the EAF dust consumption emission factor since AZR’s Monaca facility did not consume EAF dust.

The production and use of coking coal for zinc production is adjusted for within the Energy chapter as this fuel was consumed during non-energy related activities. Additional information on the adjustments made within the Energy sector for Non-Energy Use of Fuels is described in both the Methodology section of CO₂ from Fossil Fuel

1 Combustion (3.1 Fossil Fuel Combustion (CRF Source Category 1A)) and Annex 2.1, Methodology for Estimating
 2 Emissions of CO₂ from Fossil Fuel Combustion.

3 Beginning with the 2017 USGS *Minerals Commodity Summary: Zinc*, United States primary and secondary refined
 4 zinc production were reported as one value, total refined zinc production. Prior to this publication, primary and
 5 secondary refined zinc production statistics were reported separately. For the current Inventory report, EPA
 6 sought expert judgment from the USGS mineral commodity expert to assess approaches for splitting total
 7 production into primary and secondary values. For years 2016 through 2019, only one facility produced primary
 8 zinc. Primary zinc produced from this facility was subtracted from the USGS 2016 to 2019 total zinc production
 9 statistic to estimate secondary zinc production for these years.

10 Uncertainty and Time-Series Consistency – TO BE UPDATED

11 The uncertainty associated with these estimates is two-fold, relating to activity data and emission factors used.

12 First, there is uncertainty associated with the amount of EAF dust consumed in the United States to produce
 13 secondary zinc using emission-intensive Waelz kilns. The estimate for the total amount of EAF dust consumed in
 14 Waelz kilns is based on (1) an EAF dust consumption value reported annually by AZR/Horsehead Corporation as
 15 part of its financial reporting to the Securities and Exchange Commission (SEC), and (2) an EAF dust consumption
 16 value obtained from the Waelz kiln facility operated in Alabama by Steel Dust Recycling LLC. Since actual EAF dust
 17 consumption information is not available for PIZO’s facility (2009 through 2010) and SDR’s facility (2008 through
 18 2010), the amount is estimated by multiplying the EAF dust recycling capacity of the facility (available from the
 19 company’s website) by the capacity utilization factor for AZR (which is available from Horsehead Corporation
 20 financial reports). Also, the EAF dust consumption for PIZO’s facility for 2011 through 2016 was estimated by
 21 multiplying the average capacity utilization factor developed from AZR and SDR’s annual capacity utilization rates
 22 by PIZO’s EAF dust recycling capacity. Therefore, there is uncertainty associated with the assumption used to
 23 estimate PIZO and SDR’s annual EAF dust consumption values (except SDR’s EAF dust consumption for 2011
 24 through 2017, which were obtained from SDR’s recycling facility in Alabama).

25 Second, there is uncertainty associated with the emission factors used to estimate CO₂ emissions from secondary
 26 zinc production processes. The Waelz kiln emission factors are based on materials balances for metallurgical coke
 27 and EAF dust consumed as provided by Viklund-White (2000). Therefore, the accuracy of these emission factors
 28 depend upon the accuracy of these materials balances. Data limitations prevented the development of emission
 29 factors for the electrothermic process. Therefore, emission factors for the Waelz kiln process were applied to both
 30 electrothermic and Waelz kiln production processes.

31 The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-93. Zinc production CO₂
 32 emissions from 2018 were estimated to be between 0.8 and 1.2 MMT CO₂ Eq. at the 95 percent confidence level.
 33 This indicates a range of approximately 16 percent below and 16 percent above the emission estimate of 1.0 MMT
 34 CO₂ Eq.

35 **Table 4-93: Approach 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Zinc**
 36 **Production (MMT CO₂ Eq. and Percent)**

Source	Gas	2018 Emission Estimate (MMT CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a (MMT CO ₂ Eq.)			
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Zinc Production	CO ₂	1.0	0.8	1.2	-16%	+16%

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

37 Methodological approaches were applied to the entire time series to ensure consistency in emissions from 1990
 38 through 2018. Details on the emission trends through time are described in more detail in the Methodology
 39 section, above.

1 QA/QC and Verification

2 For more information on the general QA/QC process applied to this source category, consistent with Volume 1,
3 Chapter 6 of the *2006 IPCC Guidelines*, see the QA/QC and Verification Procedures section in the introduction of
4 the IPPU chapter.

5 Recalculations Discussion

6 Updated data on EAF dust consumed and EAF dust capacity was available for 2015 through 2019. Compared to the
7 previous Inventory, total CO₂ emissions decreased by between zero and six percent each year.

8 Planned Improvements

9 Pending resources and prioritization of improvements for more significant sources, EPA will continue to evaluate
10 and analyze data reported under EPA's GHGRP that would be useful to improve the emission estimates and
11 category-specific QC for the Zinc Production source category, in particular considering completeness of reported
12 zinc production given the reporting threshold. Given the small number of facilities in the United States, particular
13 attention will be made to risks for disclosing CBI and ensuring time-series consistency of the emissions estimates
14 presented in future Inventory reports, consistent with IPCC and UNFCCC guidelines. This is required as the facility-
15 level reporting data from EPA's GHGRP, with the program's initial requirements for reporting of emissions in
16 calendar year 2010, are not available for all inventory years (i.e., 1990 through 2009) as required for this Inventory.
17 In implementing improvements and integration of data from EPA's GHGRP, the latest guidance from the IPCC on
18 the use of facility-level data in national inventories will be relied upon.²⁵² This is a long-term planned improvement
19 and EPA is still assessing the possibility of including this improvement in future Inventory reports.

20 4.23 Electronics Industry (CRF Source 21 Category 2E)

22 The electronics industry uses multiple greenhouse gases in its manufacturing processes. In semiconductor
23 manufacturing, these include long-lived fluorinated greenhouse gases used for plasma etching and chamber
24 cleaning (CRF Source Category 2E1), fluorinated heat transfer fluids (CRF Source Category 2E4) used for
25 temperature control and other applications, and nitrous oxide (N₂O) used to produce thin films through chemical
26 vapor deposition (reported under CRF Source Category 2H3). Similar to semiconductor manufacturing, the
27 manufacturing of micro-electro-mechanical systems (MEMS) devices (reported under CRF Source Category 2E5
28 Other) and photovoltaic cells (CRF Source Category 2E3) requires the use of multiple long-lived fluorinated
29 greenhouse gases for various processes.

30 The gases most commonly employed in plasma etching and chamber cleaning are trifluoromethane
31 (hydrofluorocarbon (HFC)-23 or CHF₃), perfluoromethane (CF₄), perfluoroethane (C₂F₆), nitrogen trifluoride (NF₃),
32 and sulfur hexafluoride (SF₆), although other fluorinated compounds such as perfluoropropane (C₃F₈) and
33 perfluorocyclobutane (c-C₄F₈) are also used. The exact combination of compounds is specific to the process
34 employed.

35 In addition to emission estimates for these seven commonly used fluorinated gases, this Inventory contains
36 emissions estimates for N₂O and a combination of other HFCs and unsaturated, low-GWP PFCs such as C₅F₈, C₄F₆,

²⁵² See <http://www.ipcc-nggip.iges.or.jp/public/tb/TFI_Technical_Bulletin_1.pdf>.

1 HFC-32, and HFC-134a. These additional HFCs and PFCs are emitted from etching and chamber cleaning processes
2 in much smaller amounts, accounting for less than 0.02 percent of emissions (in CO₂ Eq.) from these processes.
3 These gases have been grouped as “other fluorinated gases” for the purpose of this analysis.

4 For semiconductors, a single 300 mm silicon wafer that yields between 400 to 600 semiconductor products
5 (devices or chips) may require more than 100 distinct fluorinated-gas-using process steps, principally to deposit
6 and pattern dielectric films. Plasma etching (or patterning) of dielectric films, such as silicon dioxide and silicon
7 nitride, is performed to provide pathways for conducting material to connect individual circuit components in each
8 device. The patterning process uses plasma-generated fluorine atoms, which chemically react with exposed
9 dielectric film to selectively remove the desired portions of the film. The material removed as well as undissociated
10 fluorinated gases flow into waste streams and, unless emission abatement systems are employed, into the
11 atmosphere. Plasma enhanced chemical vapor deposition (PECVD) chambers, used for depositing dielectric films,
12 are cleaned periodically using fluorinated and other gases. During the cleaning cycle the gas is converted to
13 fluorine atoms in plasma, which etches away residual material from chamber walls, electrodes, and chamber
14 hardware. Undissociated fluorinated gases and other products pass from the chamber to waste streams and,
15 unless abatement systems are employed, into the atmosphere.

16 In addition to emissions of unreacted gases, some fluorinated compounds can also be transformed in the plasma
17 processes into different fluorinated compounds which are then exhausted, unless abated, into the atmosphere.
18 For example, when C₂F₆ is used in cleaning or etching, CF₄ is typically generated and emitted as a process
19 byproduct. In some cases, emissions of the byproduct gas can rival or even exceed emissions of the input gas, as is
20 the case for NF₃ used in remote plasma chamber cleaning, which often generates CF₄ as a byproduct.

21 Besides dielectric film etching and PECVD chamber cleaning, much smaller quantities of fluorinated gases are used
22 to etch polysilicon films and refractory metal films like tungsten.

23 Nitrous oxide is used in manufacturing semiconductor devices to produce thin films by CVD and nitridation
24 processes as well as for N-doping of compound semiconductors and reaction chamber conditioning (Doering
25 2000).

26 Liquid perfluorinated compounds are also used as heat transfer fluids (F-HTFs) for temperature control, device
27 testing, cleaning substrate surfaces and other parts, and soldering in certain types of semiconductor
28 manufacturing production processes. Leakage and evaporation of these fluids during use is a source of fluorinated
29 gas emissions (EPA 2006). Unweighted F-HTF emissions consist primarily of perfluorinated amines,
30 hydrofluoroethers, perfluoropolyethers (specifically, PFPPIEs), and perfluoroalkylmorpholines. One percent or less
31 consist of HFCs, PFCs, and SF₆ (where PFCs are defined as compounds including only carbon and fluorine). With the
32 exceptions of the hydrofluoroethers and most of the HFCs, all of these compounds are very long-lived in the
33 atmosphere and have global warming potentials (GWPs) near 10,000.²⁵³

34 For 2019, total GWP-weighted emissions of all fluorinated greenhouse gases and N₂O from deposition, etching,
35 and chamber cleaning processes in the U.S. semiconductor industry were estimated to be 4.6 MMT CO₂ Eq. Less
36 than 0.02 percent of total emissions from semiconductor manufacturing consist of a combination of HFCs other
37 than HFC-23 and unsaturated, low-GWP PFCs including C₄F₆, C₄F₈O, C₅F₈, HFC-32, HFC-41, and HFC-134a. These
38 gases have been grouped as “Other F-GHGs”. Emissions from all fluorinated greenhouse gases and N₂O are
39 presented in Table 4-94 and Table 4-95 below for the years 1990, 2005, and the period 2015 to 2019. Emissions of
40 F-HTFs that are HFCs, PFCs or SF₆ are presented in Table 4-94. Table 4-96 shows F-HTF emissions in tons by
41 compound group based on reporting to EPA’s Greenhouse Gas Reporting Program (GHGRP) during years 2013

²⁵³ The GWP of PFPPIE, a perfluoropolyether used as an F-HTF, is included in the *IPCC Fourth Assessment Report* with a value of 10,300. The GWPs of the perfluorinated amines and perfluoroalkylmorpholines that are used as F-HTFs have not been evaluated in the peer-reviewed literature. However, evaluations by the manufacturer indicate that their GWPs are near 10,000 (78 FR 20632), which is expected given that these compounds are both saturated and fully fluorinated. EPA assigns a default GWP of 10,000 to compounds that are both saturated and fully fluorinated and that do not have chemical-specific GWPs in either the Fourth or the Fifth Assessment Reports.

1 through 2019. Emissions of F-HTFs that are not HFCs, PFCs or SF₆ are not included in inventory totals and are
2 included for informational purposes only.

3 The rapid growth of this industry and the increasing complexity (growing number of layers)²⁵⁴ of semiconductor
4 products led to an increase in emissions of 153 percent between 1990 and 1999, when emissions peaked at 9.1
5 MMT CO₂ Eq. Emissions began to decline after 1999, reaching a low point in 2009 before rebounding slightly and
6 more or less plateauing at the current level, which represents a 49 percent decline from 1999 levels. Together,
7 industrial growth, adoption of emissions reduction technologies (including but not limited to abatement
8 technologies) and shifts in gas usages resulted in a net increase in emissions of approximately 29 percent between
9 1990 and 2019. Total emissions from semiconductor manufacture in 2019 were slightly lower than 2018 emissions,
10 decreasing by 9 percent. This is likely due in part to reduced production in 2019 as compared to 2018. Increased
11 abatement of F-GHGs also contributed to the decrease in emissions.

12 The emissions reported by facilities manufacturing MEMS included emissions of C₂F₆, C₃F₈, c-C₄F₈, CF₄, HFC-23, NF₃,
13 and SF₆,²⁵⁵ and were equivalent to only 0.09 percent to 0.34 percent of the total reported emissions from
14 electronics manufacturing in 2011 to 2019. Emissions ranged from 0.0009 to 0.0185 MMT CO₂ Eq. from 1991 to
15 2019. Based upon information in the World Fab Forecast (WFF), it appears that some GHGRP reporters that
16 manufacture both semiconductors and MEMS are reporting their emissions as only from semiconductor
17 manufacturing (GHGRP reporters must choose a single classification per fab). Emissions from non-reporters have
18 not been estimated.

19 Total GWP-weighted emissions from manufacturing of photovoltaic cells were estimated to range from 0.0003
20 MMT CO₂ Eq. to 0.0326 MMT CO₂ Eq. from 1998 to 2019 and were equivalent to between 0.003 percent to 0.67
21 percent of the total reported emissions from electronics manufacturing. Emissions from manufacturing of
22 photovoltaic cells were estimated based on reported data from a single manufacturer between 2015 and 2017.
23 Reported emissions from photovoltaic cell manufacturing consisted of CF₄, C₂F₆, c-C₄F₈, and CHF₃.²⁵⁶

24 Emissions from all fluorinated greenhouse gases from photovoltaic and MEMS manufacturing are in Table 4-94.
25 While EPA has developed an elementary methodology to estimate emissions from non-reporters and to back-cast
26 emissions from these sources for the entire time series, there is very high uncertainty associated with these
27 emissions.

28 Only F-HTF emissions that consist of HFC, PFC and SF₆ are included in the Inventory totals; emissions of other F-
29 HTFs, which account for the vast majority of F-HTF emissions, are provided for informational purposes and are not
30 included in the Inventory totals. Since reporting of F-HTF emissions began under EPA's GHGRP in 2011, total F-HTF
31 emissions (reported and estimated non-reported) have fluctuated between 0.6 MMT CO₂ Eq. and 0.9 MMT CO₂
32 Eq., with an overall declining trend. An analysis of the data reported to EPA's GHGRP indicates that F-HTF
33 emissions account for anywhere between 13 percent and 19 percent of total annual emissions (F-GHG, N₂O and F-

²⁵⁴ Complexity is a term denoting the circuit required to connect the active circuit elements (transistors) on a chip. Increasing miniaturization, for the same chip size, leads to increasing transistor density, which, in turn, requires more complex interconnections between those transistors. This increasing complexity is manifested by increasing the levels (i.e., layers) of wiring, with each wiring layer requiring fluorinated gas usage for its manufacture.

²⁵⁵ Gases not reported by MEMS manufacturers to the GHGRP are currently listed as "NE" in the CRF. Since no facilities report using these gases, emissions of these gases are not estimated for this sub-sector. However, there is insufficient data to definitively conclude that they are not used by non-reporting facilities.

²⁵⁶ Gases not reported by PV manufacturers to the GHGRP are currently listed as "NE" in the CRF. Since no facilities report using these gases, emissions of these gases are not estimated for this sub-sector. However, there is insufficient data to definitively conclude that they are not used by non-reporting facilities.

1 HTFs) from semiconductor manufacturing.²⁵⁷ Table 4-96 shows F-HTF emissions in tons by compound group based
 2 on reporting to EPA's GHGRP during years 2012 through 2019.²⁵⁸

3 **Table 4-94: PFC, HFC, SF₆, NF₃, and N₂O Emissions from Electronics Manufacture²⁵⁹ (MMT**
 4 **CO₂ Eq.)**

Year	1990	2005	2015	2016	2017	2018	2019
CF ₄	0.8	1.1	1.5	1.5	1.6	1.7	1.6
C ₂ F ₆	2.0	2.0	1.3	1.2	1.2	1.1	0.9
C ₃ F ₈	+	0.1	0.1	0.1	0.1	0.1	0.1
c-C ₄ F ₈	0.0	0.1	0.1	0.1	0.1	0.1	0.1
HFC-23	0.2	0.2	0.3	0.3	0.4	0.4	0.3
SF ₆	0.5	0.7	0.7	0.8	0.7	0.8	0.8
NF ₃	+	0.5	0.6	0.6	0.6	0.6	0.6
Other F-GHGs	+	+	+	+	+	+	+
Total F-GHGs	3.6	4.6	4.7	4.7	4.6	4.8	4.3
N ₂ O ²⁶⁰	+	0.1	0.2	0.2	0.3	0.3	0.2
HFC, PFC and SF ₆ F-HTFs	0.000	0.012	0.019	0.018	0.021	0.022	0.029
MEMS	0.000	0.013	0.006	0.005	0.006	0.008	0.011
PV	0.000	0.005	0.033	0.029	0.029	0.029	0.029
Total	3.6	4.8	5.0	5.0	4.9	5.1	4.6

+ Does not exceed 0.5 kt

5 **Table 4-95: PFC, HFC, SF₆, NF₃, and N₂O Emissions from Electronics Manufacture (Metric**
 6 **Tons)**

Year	1990	2005	2015	2016	2017	2018	2019
CF ₄	115	146	206	208	218	232	214
C ₂ F ₆	160	162	110	99	96	92	77
C ₃ F ₈	0	9	16	14	12	12	10
c-C ₄ F ₈	0	11	6	5	6	6	6
HFC-23	15	14	22	23	24	25	21
SF ₆	22	31	32	36	31	33	33
NF ₃	3	29	33	33	35	36	35
N ₂ O	120	412	789	792	920	857	755
Total	435	813	1,213	1,212	1,342	1,293	1,151

7 **Table 4-96: F-HTF Emissions from Electronics Manufacture by Compound Group (Metric**
 8 **Tons)**

Year	2013	2014	2015	2016	2017	2018	2019
HFCs	4.6	2.0	1.6	2.7	1.7	1.7	2.4

²⁵⁷ Emissions data for HTFs (in tons of gas) from the semiconductor industry from 2011 through 2019 were obtained from the EPA GHGRP annual facility emissions reports.

²⁵⁸ Many fluorinated heat transfer fluids consist of perfluoropolymethylisopropyl ethers (PFPMIEs) of different molecular weights and boiling points that are distilled from a mixture. "BP 200 °C" (and similar terms below) indicate the boiling point of the fluid in degrees Celsius. For more information, see <<https://www.regulations.gov/document?D=EPA-HQ-OAR-2009-0927-0276>>.

²⁵⁹ An extremely small portion of emissions included in the totals for Electronics Manufacture are from the manufacturing of MEMS and photovoltaic cells.

²⁶⁰ Emissions of N₂O from semiconductor manufacturing are reported in the CRF under 2H3.

PFCs	0.4	0.2	0.3	0.3	0.2	0.4	0.3
SF ₆	0.4	0.9	0.6	0.5	0.7	0.6	0.3
HFEs	25.4	25.2	19.0	13.5	16.5	23.3	7.2
PFPMEs	18.8	18.2	20.8	17.3	14.3	17.7	16.2
Perfluoroalkylmorpholines	10.7	10.8	8.1	7.6	5.2	5.9	5.7
Perfluorotrialkylamines	29.5	49.3	43.8	38.6	37.6	40.0	34.4
Total F-HTFs	89.9	106.7	94.4	80.6	76.2	89.7	66.4

1

2 **Table 4-97: F-GHG^a Emissions from PV and MEMS manufacturing (MMT CO₂ Eq.)**

Year	1990	2005	2015	2016	2017	2018	2019
MEMS	0.0	0.013	0.006	0.005	0.006	0.008	0.011
PV	0.0	0.005	0.033	0.029	0.029	0.029	0.029

^a F-GHGs from PV manufacturing include an unspecified mix of HFCs and PFCs, F-GHGs from MEMS manufacturing includes those gases but also NF₃ and SF₆.

3 Methodology

4 Emissions are based on data reported through Subpart I, Electronics Manufacture, of EPA's GHGRP, Partner-
5 reported emissions data received through EPA's PFC²⁶¹ Reduction/Climate Partnership, EPA's PFC Emissions
6 Vintage Model (PEVM)—a model that estimates industry emissions from etching and chamber cleaning processes
7 in the absence of emission control strategies (Burton and Beizaie 2001)²⁶²—and estimates of industry activity (i.e.,
8 total manufactured layer area). The availability and applicability of reported emissions data from the EPA
9 Partnership and EPA's GHGRP and activity data differ across the 1990 through 2019 time series. Consequently,
10 fluorinated greenhouse gas (F-GHG) emissions from etching and chamber cleaning processes for semiconductors
11 were estimated using seven distinct methods, one each for the periods 1990 through 1994, 1995 through 1999,
12 2000 through 2006, 2007 through 2010, 2011 and 2012, 2013 and 2014, and 2015 through 2019. Nitrous oxide
13 emissions were estimated using five distinct methods, one each for the period 1990 through 1994, 1995 through
14 2010, 2011 and 2012, 2013 and 2014, and 2015 through 2019. The methodology discussion below for these time
15 periods focuses on semiconductor emissions from etching, chamber cleaning, and uses of N₂O. Other emissions for
16 MEMS, PV, and HTFs were estimated using the approaches described immediately below.

17 GHGRP-reported emissions from the manufacturing of MEMS are available for the years 2011 to 2019. Emissions
18 from fabs that reported to the GHGRP as manufacturing MEMS are not included in the semiconductor
19 manufacturing totals reported above. Emissions from manufacturing of MEMS for years prior to 2011 were
20 calculated by linearly interpolating emissions between 1990 (at zero MMT CO₂ Eq.) and 2011, the first year where
21 emissions from manufacturing of MEMS was reported to the GHGRP. Based upon information in the World Fab
22 Forecast (WFF), it appears that some GHGRP reporters that manufacture both semiconductors and MEMS are
23 reporting their emissions as only from semiconductor manufacturing; however, emissions from MEMS
24 manufacturing are likely being included in semiconductor totals. Emissions were not estimated for non-reporters.

25 GHGRP-reported emissions from the manufacturing of photovoltaic cells are only available between 2015 and
26 2017 and are from a single manufacturer. These reported emissions are scaled by the ratio of reporters to non-
27 reporters to estimate the total U.S. emissions from PV. EPA estimates the emissions from manufacturing of PVs
28 from non-reporting facilities by multiplying the estimated capacity of non-reporters by a calculated emissions

²⁶¹ In the context of the EPA Partnership and PEVM, PFC refers to perfluorocompounds, not perfluorocarbons.

²⁶² A Partner refers to a participant in the U.S. EPA PFC Reduction/Climate Partnership for the Semiconductor Industry. Through a Memorandum of Understanding (MoU) with the EPA, Partners voluntarily reported their PFC emissions to the EPA by way of a third party, which aggregated the emissions through 2010.

1 factor based on GHGRP reported emissions per megawatt from 2015 and 2016. Manufacturing capacities in
2 megawatts were drawn from DisplaySearch, a 2015 Congressional Research Service Report on U.S. Solar
3 Photovoltaic Manufacturing,²⁶³ and self-reported capacity by the GHGRP reporter.²⁶⁴ EPA estimated that during
4 the 2015 to 2017 period, 28 percent of emissions were reported through the GHGRP. These capacities are
5 estimated for the full time series by linearly scaling the total U.S. capacity between zero in 1997 to the total
6 capacity reported of crystalline silicon (c-Si) PV manufacturing in 2000 in DisplaySearch and then linearly scaling
7 between the total capacity of c-Si PV manufacturing in DisplaySearch in 2009 to the total capacity of c-Si PV
8 manufacturing reported in the Congressional Research Service report in 2012. Capacities were held constant for
9 non-reporters for 2012 to 2019. Average emissions per MW from the GHGRP reporter in 2015 and 2016 were then
10 applied to the total capacity prior to 2015. Emissions for 2014 from the GHGRP reporter were scaled to the
11 number of months open in 2014. For 2016 and 2017, emissions per MW (capacity) from the GHGRP reporter were
12 applied to the non-reporters. For 2018 and 2019, emissions were held constant to 2017 estimates, since there is
13 no evidence that much growth has occurred in the U.S. PV cell manufacturing industry in the last two years.

14 Facility emissions of F-HTFs from semiconductor manufacturing are reported to EPA under its GHGRP and are
15 available for the years 2011 through 2019. EPA estimates the emissions of F-HTFs from non-reporting facilities by
16 calculating the ratio of GHGRP-reported fluorinated HTF emissions to GHGRP reported F-GHG emissions from
17 etching and chamber cleaning processes, and then multiplying this ratio by the F-GHG emissions from etching and
18 chamber cleaning processes estimated for non-reporting facilities. Fluorinated HTF use in semiconductor
19 manufacturing is assumed to have begun in the early 2000s and to have gradually displaced other HTFs (e.g., de-
20 ionized water and glycol) in electronics manufacturing (EPA 2006). For time-series consistency, EPA interpolated
21 the share of F-HTF emissions to F-GHG emissions between 2000 (at 0 percent) and 2011 (at 22 percent) and
22 applied these shares to the unadjusted F-GHG emissions during those years to estimate the fluorinated HTF
23 emissions.

24 **1990 through 1994**

25 From 1990 through 1994, Partnership data were unavailable and emissions were modeled using PEVM (Burton and
26 Beizaie 2001).²⁶⁵ The 1990 to 1994 emissions are assumed to be uncontrolled, since reduction strategies such as
27 chemical substitution and abatement were yet to be developed.

28 PEVM is based on the recognition that fluorinated greenhouse gas emissions from semiconductor manufacturing
29 vary with: (1) the number of layers that comprise different kinds of semiconductor devices, including both silicon
30 wafer and metal interconnect layers, and (2) silicon consumption (i.e., the area of semiconductors produced) for
31 each kind of device. The product of these two quantities, Total Manufactured Layer Area (TMLA), constitutes the
32 activity data for semiconductor manufacturing. PEVM also incorporates an emission factor that expresses
33 emissions per unit of manufactured layer-area. Emissions are estimated by multiplying TMLA by this emission
34 factor.

35 PEVM incorporates information on the two attributes of semiconductor devices that affect the number of layers:
36 (1) linewidth technology (the smallest manufactured feature size),²⁶⁶ and (2) product type (discrete, memory or

²⁶³ Platzer, Michaela D. (2015) *U.S. Solar Photovoltaic Manufacturing: Industry Trends, Global Competition, Federal Support*. Congressional Research Service. January 27, 2015. <<https://fas.org/sgp/crs/misc/R42509.pdf>>.

²⁶⁴ DisplaySearch. 2010. DisplaySearch Q4'09 Quarterly FPD Supply/Demand and Capital Spending Report. DisplaySearch, LLC.

²⁶⁵ Various versions of the PEVM exist to reflect changing industrial practices. From 1990 to 1994 emissions estimates are from PEVM v1.0, completed in September 1998. The emission factor used to estimate 1990 to 1994 emissions is an average of the 1995 and 1996 emissions factors, which were derived from Partner reported data for those years.

²⁶⁶ By decreasing features of Integrated Circuit components, more components can be manufactured per device, which increases its functionality. However, as those individual components shrink it requires more layers to interconnect them to achieve the functionality. For example, a microprocessor manufactured with 65 nm feature sizes might contain as many as 1 billion transistors and require as many as 11 layers of component interconnects to achieve functionality, while a device

1 logic).²⁶⁷ For each linewidth technology, a weighted average number of layers is estimated using VLSI product-
2 specific worldwide silicon demand data in conjunction with complexity factors (i.e., the number of layers per
3 Integrated Circuit (IC) specific to product type (Burton and Beizaie 2001; ITRS 2007). PEVM derives historical
4 consumption of silicon (i.e., square inches) by linewidth technology from published data on annual wafer starts
5 and average wafer size (VLSI Research, Inc. 2012).

6 The emission factor in PEVM is the average of four historical emission factors, each derived by dividing the total
7 annual emissions reported by the Partners for each of the four years between 1996 and 1999 by the total TMLA
8 estimated for the Partners in each of those years. Over this period, the emission factors varied relatively little (i.e.,
9 the relative standard deviation for the average was 5 percent). Since Partners are believed not to have applied
10 significant emission reduction measures before 2000, the resulting average emission factor reflects uncontrolled
11 emissions and hence may be use here to estimate 1990 through 1994 emissions. The emission factor is used to
12 estimate U.S. uncontrolled emissions using publicly-available data on world (including U.S.) silicon consumption.

13 As it was assumed for this time period that there was no consequential adoption of fluorinated-gas-reducing
14 measures, a fixed distribution of fluorinated-gas use was assumed to apply to the entire U.S. industry to estimate
15 gas-specific emissions. This distribution was based upon the average fluorinated-gas purchases made by
16 semiconductor manufacturers during this period and the application of IPCC default emission factors for each gas
17 (Burton and Beizaie 2001).

18 PEVM only addressed the seven main F-GHGs (CF₄, C₂F₆, C₃F₈, c-C₄F₈, HFC-23, SF₆, and NF₃) used in semiconductor
19 manufacturing. Through reporting under Subpart I of EPA's GHGRP, data on other F-GHGs (C₄F₆, C₅F₈, HFC-32, HFC-
20 41, HFC-134a) used in semiconductor manufacturing became available and EPA was therefore able to extrapolate
21 this data across the entire 1990 to 2018 timeseries. To estimate emissions for these "other F-GHGs", emissions
22 data from Subpart I were used to estimate the average share or percentage contribution of these gases as
23 compared to total F-GHG emissions and then these shares were applied to all years prior to reported data from
24 Subpart I (1990 through 2010) and to the emissions from non-reporters from 2011 to 2018.

25 To estimate N₂O emissions, it is assumed the proportion of N₂O emissions estimated for 1995 (discussed below)
26 remained constant for the period of 1990 through 1994.

27 **1995 through 1999**

28 For 1995 through 1999, total U.S. emissions were extrapolated from the total annual emissions reported by the
29 Partners (1995 through 1999). Partner-reported emissions are considered more representative (e.g., in terms of
30 capacity utilization in a given year) than PEVM-estimated emissions, and are used to generate total U.S. emissions
31 when applicable. The emissions reported by the Partners were divided by the ratio of the total capacity of the
32 plants operated by the Partners and the total capacity of all of the semiconductor plants in the United States; this
33 ratio represents the share of capacity attributable to the Partnership. This method assumes that Partners and non-
34 Partners have identical capacity utilizations and distributions of manufacturing technologies. Plant capacity data is
35 contained in the World Fab Forecast (WFF) database and its predecessors, which is updated quarterly. Gas-specific
36 emissions were estimated using the same method as for 1990 through 1994.

37 For this time period emissions of other F-GHGs (C₄F₆, C₅F₈, HFC-32, HFC-41, HFC-134a) were estimated using the
38 method described above for 1990 to 1994.

39 For this time period, the N₂O emissions were estimated using an emission factor that was applied to the annual,
40 total U.S. TMLA manufactured. The emission factor was developed using a regression-through-the-origin (RTO)

manufactured with 130 nm feature size might contain a few hundred million transistors and require 8 layers of component interconnects (ITRS 2007).

²⁶⁷ Memory devices manufactured with the same feature sizes as microprocessors (a logic device) require approximately one-half the number of interconnect layers, whereas discrete devices require only a silicon base layer and no interconnect layers (ITRS 2007). Since discrete devices did not start using PFCs appreciably until 2004, they are only accounted for in the PEVM emissions estimates from 2004 onwards.

1 model: GHGRP reported N₂O emissions were regressed against the corresponding TMLA of facilities that reported
2 no use of abatement systems. Details on EPA's GHGRP reported emissions and development of emission factor
3 using the RTO model are presented in the 2011 through 2012 section. The total U.S. TMLA for 1995 through 1999
4 was estimated using PEVM.

5 **2000 through 2006**

6 Emissions for the years 2000 through 2006—the period during which Partners began the consequential application
7 of fluorinated greenhouse gas-reduction measures—were estimated using a combination of Partner-reported
8 emissions and adjusted PEVM modeled emissions. The emissions reported by Partners for each year were
9 accepted as the quantity emitted from the share of the industry represented by those Partners. Remaining
10 emissions, those from non-Partners, were estimated using PEVM, with one change. To ensure time-series
11 consistency and to reflect the increasing use of remote clean technology (which increases the efficiency of the
12 production process while lowering emissions of fluorinated greenhouse gases), the average non-Partner emission
13 factor (PEVM emission factor) was assumed to begin declining gradually during this period. Specifically, the non-
14 Partner emission factor for each year was determined by linear interpolation, using the end points of 1999 (the
15 original PEVM emission factor) and 2011 (a new emission factor determined for the non-Partner population based
16 on GHGRP-reported data, described below).

17 The portion of the U.S. total emissions attributed to non-Partners is obtained by multiplying PEVM's total U.S.
18 emissions figure by the non-Partner share of U.S. total silicon capacity for each year as described above.²⁶⁸ Gas-
19 specific emissions from non-Partners were estimated using linear interpolation between the gas-specific emissions
20 distributions of 1999 (assumed to be the same as that of the total U.S. Industry in 1994) and 2011 (calculated from
21 a subset of non-Partners that reported through the GHGRP as a result of emitting more than 25,000 MT CO₂ Eq.
22 per year). Annual updates to PEVM reflect published figures for actual silicon consumption from VLSI Research,
23 Inc., revisions and additions to the world population of semiconductor manufacturing plants, and changes in IC
24 fabrication practices within the semiconductor industry (see ITRS 2008 and Semiconductor Equipment and
25 Materials Industry 2011).^{269, 270, 271}

26 For this time period emissions of other F-GHGs (C₄F₆, C₅F₈, HFC-32, HFC-41, HFC-134a) were estimated using the

²⁶⁸ This approach assumes that the distribution of linewidth technologies is the same between Partners and non-Partners. As discussed in the description of the method used to estimate 2007 emissions, this is not always the case.

²⁶⁹ Special attention was given to the manufacturing capacity of plants that use wafers with 300 mm diameters because the actual capacity of these plants is ramped up to design capacity, typically over a 2 to 3 year period. To prevent overstating estimates of partner-capacity shares from plants using 300 mm wafers, *design* capacities contained in WFF were replaced with estimates of *actual installed* capacities for 2004 published by Citigroup Smith Barney (2005). Without this correction, the partner share of capacity would be overstated, by approximately 5 percent. For perspective, approximately 95 percent of all new capacity additions in 2004 used 300 mm wafers, and by year-end those plants, on average, could operate at approximately 70 percent of the design capacity. For 2005, actual installed capacities were estimated using an entry in the World Fab Watch database (April 2006 Edition) called "wafers/month, 8-inch equivalent," which denoted the actual installed capacity instead of the fully-ramped capacity. For 2006, actual installed capacities of new fabs were estimated using an average monthly ramp rate of 1100 wafer starts per month (wspm) derived from various sources such as semiconductor fabtech, industry analysts, and articles in the trade press. The monthly ramp rate was applied from the first-quarter of silicon volume (FQSV) to determine the average design capacity over the 2006 period.

²⁷⁰ In 2006, the industry trend in co-ownership of manufacturing facilities continued. Several manufacturers, who are Partners, now operate fabs with other manufacturers, who in some cases are also Partners and in other cases are not Partners. Special attention was given to this occurrence when estimating the Partner and non-Partner shares of U.S. manufacturing capacity.

²⁷¹ Two versions of PEVM are used to model non-Partner emissions during this period. For the years 2000 to 2003 PEVM v3.2.0506.0507 was used to estimate non-Partner emissions. During this time, discrete devices did not use PFCs during manufacturing and therefore only memory and logic devices were modeled in the PEVM v3.2.0506.0507. From 2004 onwards, discrete device fabrication started to use PFCs, hence PEVM v4.0.0701.0701, the first version of PEVM to account for PFC emissions from discrete devices, was used to estimate non-Partner emissions for this time period.

1 method described above for 1990 to 1994.
2 Nitrous oxide emissions were estimated using the same methodology as the 1995 through 1999 methodology.

3 **2007 through 2010**

4 For the years 2007 through 2010, emissions were also estimated using a combination of Partner reported
5 emissions and adjusted PEVM modeled emissions to provide estimates for non-Partners; however, two
6 improvements were made to the estimation method employed for the previous years in the time series. First, the
7 2007 through 2010 emission estimates account for the fact that Partners and non-Partners employ different
8 distributions of manufacturing technologies, with the Partners using manufacturing technologies with greater
9 transistor densities and therefore greater numbers of layers.²⁷² Second, the scope of the 2007 through 2010
10 estimates was expanded relative to the estimates for the years 2000 through 2006 to include emissions from
11 research and development (R&D) fabs. This additional enhancement was feasible through the use of more detailed
12 data published in the WFF. PEVM databases were updated annually as described above. The published world
13 average capacity utilization for 2007 through 2010 was used for production fabs, while for R&D fabs a 20 percent
14 figure was assumed (SIA 2009).

15 In addition, publicly-available utilization data was used to account for differences in fab utilization for
16 manufacturers of discrete and IC products for 2010 emissions for non-Partners. The Semiconductor Capacity
17 Utilization (SICAS) Reports from SIA provides the global semiconductor industry capacity and utilization,
18 differentiated by discrete and IC products (SIA 2009 through 2011). PEVM estimates were adjusted using
19 technology-weighted capacity shares that reflect the relative influence of different utilization. Gas-specific
20 emissions for non-Partners were estimated using the same method as for 2000 through 2006.

21 For this time period emissions of other F-GHGs (C₅F₈, CH₂F₂, CH₃F, CH₂FCF₃, C₂H₂F₄) were estimated using the
22 method described above for 1990 to 1994.

23 Nitrous oxide emissions were estimated using the same methodology as the 1995 through 1999 methodology.

24 **2011 through 2012**

25 The fifth method for estimating emissions from semiconductor manufacturing covers the period 2011 through
26 2012. This methodology differs from previous years because the EPA's Partnership with the semiconductor
27 industry ended (in 2010) and reporting under EPA's GHGRP began. Manufacturers whose estimated uncontrolled
28 emissions equal or exceed 25,000 MT CO₂ Eq. per year (based on default F-GHG-specific emission factors and total
29 capacity in terms of substrate area) are required to report their emissions to EPA. This population of reporters to
30 EPA's GHGRP included both historical Partners of EPA's PFC Reduction/Climate Partnership as well as non-Partners
31 some of which use gallium arsenide (GaAs) technology in addition to Si technology.²⁷³ Emissions from the
32 population of manufacturers that were below the reporting threshold were also estimated for this time period
33 using EPA-developed emission factors and estimates of facility-specific production obtained from WFF. Inventory
34 totals reflect the emissions from both reporting and non-reporting populations.

35 Under EPA's GHGRP, semiconductor manufacturing facilities report emissions of F-GHGs (for all types of F-GHGs)
36 used in etch and clean processes as well as emissions of fluorinated heat transfer fluids. (Fluorinated heat transfer
37 fluids are used to control process temperatures, thermally test devices, and clean substrate surfaces, among other
38 applications.) They also report N₂O emissions from CVD and other processes. The F-GHGs and N₂O were

²⁷² EPA considered applying this change to years before 2007, but found that it would be difficult due to the large amount of data (i.e., technology-specific global and non-Partner TMLA) that would have to be examined and manipulated for each year. This effort did not appear to be justified given the relatively small impact of the improvement on the total estimate for 2007 and the fact that the impact of the improvement would likely be lower for earlier years because the estimated share of emissions accounted for by non-Partners is growing as Partners continue to implement emission-reduction efforts.

²⁷³ GaAs and Si technologies refer to the wafer on which devices are manufactured, which use the same PFCs but in different ways.

1 aggregated, by gas, across all semiconductor manufacturing GHGRP reporters to calculate gas-specific emissions
2 for the GHGRP-reporting segment of the U.S. industry. At this time, emissions that result from heat transfer fluid
3 use that are HFC, PFC and SF₆ are included in the total emission estimates from semiconductor manufacturing, and
4 these GHGRP-reported emissions have been compiled and presented in Table 4-94. F-HTF emissions resulting from
5 other types of gases (e.g., HFEs) are not presented in semiconductor manufacturing totals in Table 4-94 and Table
6 4-95 but are shown in Table 4-96 for informational purposes.

7 Changes to the default emission factors and default destruction or removal efficiencies (DREs) used for GHGRP
8 reporting affected the emissions trend between 2013 and 2014. These changes did not reflect actual emission rate
9 changes but data improvements. Therefore, for the current Inventory, EPA adjusted the time series of GHGRP-
10 reported data for 2011 through 2013 to ensure time-series consistency using a series of calculations that took into
11 account the characteristics of a facility (e.g., wafer size and abatement use). To adjust emissions for facilities that
12 did not report abatement in 2011 through 2013, EPA simply applied the revised emission factors to each facility's
13 estimated gas consumption by gas, process type and wafer size. In 2014, EPA also started collecting information on
14 fab-wide DREs and the gases abated by process type, which were used in calculations for adjusting emissions from
15 facilities that abated F-GHGs in 2011 through 2013.

- 16 • To adjust emissions for facilities that abated emissions in 2011 through 2013, EPA first calculated the
17 quantity of gas abated in 2014 using reported F-GHG emissions, the revised default DREs (or the
18 estimated site-specific DRE,²⁷⁴ if a site-specific DRE was indicated), and the fab-wide DREs reported in
19 2014.²⁷⁵ To adjust emissions for facilities that abated emissions in 2011 through 2013, EPA first estimated
20 the percentage of gas passing through abatement systems for remote plasma clean in 2014 using the ratio
21 of emissions reported for CF₄ and NF₃.
- 22 • EPA then estimated the quantity of NF₃ abated for remote plasma clean in 2014 using the ratio of
23 emissions reported for CF₄ (which is not abated) and NF₃. This abated quantity was then subtracted from
24 the total abated quantity calculated as described in the bullet above.
- 25 • To account for the resulting remaining abated quantity, EPA assumed that the percentage of gas passing
26 through abatement systems was the same across all remaining gas and process type combinations where
27 abatement was reported for 2014.
- 28 • The percentage of gas abated was then assumed to be the same in 2011 through 2013 (if the facility
29 claimed abatement that year) as in 2014 for each gas abated in 2014.

30 The revised emission factors and DREs were then applied to the estimated gas consumption for each facility by gas,
31 process type and wafer size.²⁷⁶

32 For the segment of the semiconductor industry that is below EPA's GHGRP reporting threshold, and for R&D
33 facilities, which are not covered by EPA's GHGRP, emission estimates are based on EPA-developed emission factors
34 for the F-GHGs and N₂O and estimates of manufacturing activity. The new emission factors (in units of mass of CO₂
35 Eq./TMLA [million square inches (MSI)]) are based on the emissions reported under EPA's GHGRP by facilities
36 without abatement and on the TMLA estimates for these facilities based on the WFF (SEMI 2012, 2013).²⁷⁷ In a

²⁷⁴ EPA generally assumed site-specific DREs were as follows: CF₄, Etch (90 percent); all other gases, Etch (98 percent); NF₃,
Clean (95 percent); CF₄, Clean (80 percent), and all other gases, Clean (80 percent). There were a few exceptions where a higher
DRE was assumed to ensure the calculations operated correctly when there was 100 percent abatement.

²⁷⁵ If abatement information was not available for 2014 or the reported incorrectly in 2014, data from 2015 or 2016 was
substituted.

²⁷⁶ Since facilities did not report by fab before 2014, fab-wide DREs were averaged if a facility had more than one fab. For
facilities that reported more than one wafer size per facility, the percentages of a facility's emissions per wafer size were
estimated in 2014 and applied to earlier years, if possible. If the percentage of emissions per wafer size were unknown, a 50/50
split was used.

²⁷⁷ EPA does not have information on fab-wide DREs for this time period, so it is not possible to estimate uncontrolled
emissions from fabs that reported point-of-use abatement. These fabs were therefore excluded from the regression analysis.
(They are still included in the national totals.)

1 refinement of the method used to estimate emissions for the non-Partner population for prior years, different
2 emission factors were developed for different subpopulations of fabs, disaggregated by wafer size (200 mm and
3 300 mm). For each of these groups, a subpopulation-specific emission factor was obtained using a regression-
4 through-the-origin (RTO) model: facility-reported aggregate emissions of seven F-GHGs (CF₄, C₂F₆, C₃F₈, c-C₄F₈,
5 CHF₃, SF₆ and NF₃)²⁷⁸ were regressed against the corresponding TMLA to estimate an aggregate F-GHG emissions
6 factor (CO₂ Eq./MSI TMLA), and facility-reported N₂O emissions were regressed against the corresponding TMLA to
7 estimate a N₂O emissions factor (CO₂ Eq./MSI TMLA). For each subpopulation, the slope of the RTO model is the
8 emission factor for that subpopulation. Information on the use of point-of-use abatement by non-reporting fabs
9 was not available; thus, EPA conservatively assumed that non-reporting facilities did not use point-of-use
10 abatement.

11 For 2011 and 2012, estimates of TMLA relied on the capacity utilization of the fabs published by the U.S. Census
12 Bureau's Historical Data Quarterly Survey of Plant Capacity Utilization (USCB 2011, 2012). Similar to the
13 assumption for 2007 through 2010, facilities with only R&D activities were assumed to utilize only 20 percent of
14 their manufacturing capacity. All other facilities in the United States are assumed to utilize the average percent of
15 the manufacturing capacity without distinguishing whether fabs produce discrete products or logic products.

16 Non-reporting fabs were then broken out into subpopulations by wafer size (200 mm and 300 mm). using
17 information available through the WFF. The appropriate emission factor was applied to the total TMLA of each
18 subpopulation of non-reporting facilities to estimate the GWP-weighted emissions of that subpopulation.

19 Gas-specific, GWP-weighted emissions for each subpopulation of non-reporting facilities were estimated using the
20 corresponding reported distribution of gas-specific, GWP-weighted emissions from which the aggregate emission
21 factors, based on GHGRP-reported data, were developed. Estimated in this manner, the non-reporting population
22 accounted for 4.9 and 5.0 percent of U.S. emissions in 2011 and 2012, respectively. The GHGRP-reported emissions
23 and the calculated non-reporting population emissions are summed to estimate the total emissions from
24 semiconductor manufacturing.

25 **2013 and 2014**

26 For 2013 and 2014, as for 2011 and 2012, F-GHG and N₂O emissions data received through EPA's GHGRP were
27 aggregated, by gas, across all semiconductor-manufacturing GHGRP reporters to calculate gas-specific emissions
28 for the GHGRP-reporting segment of the U.S. industry. However, for these years WFF data was not available.
29 Therefore, an updated methodology that does not depend on the WFF derived activity data was used to estimate
30 emissions for the segment of the industry that are not covered by EPA's GHGRP. For the facilities that did not
31 report to the GHGRP (i.e., which are below EPA's GHGRP reporting threshold or are R&D facilities), emissions were
32 estimated based on the proportion of total U.S. emissions attributed to non-reporters for 2011 and 2012. EPA used
33 a simple averaging method by first estimating this proportion for both F-GHGs and N₂O for 2011, 2012, and 2015
34 through 2019, resulting in one set of proportions for F-GHGs and one set for N₂O, and then applied the average of
35 each set to the 2013 and 2014 GHGRP reported emissions to estimate the non-reporters' emissions. Fluorinated
36 gas-specific, GWP-weighted emissions for non-reporters were estimated using the corresponding reported
37 distribution of gas-specific, GWP-weighted emissions reported through EPA's GHGRP for 2013 and 2014.

38 GHGRP-reported emissions in 2013 were adjusted to capture changes to the default emission factors and default
39 destruction or removal efficiencies used for GHGRP reporting, affecting the emissions trend between 2013 and
40 2014. EPA used the same method to make these adjustments as described above for 2011 and 2012 GHGRP data.

41 **2015 through 2019**

42 Similar to the methods described above for 2011 and 2012, and 2013 and 2014, EPA relied upon emissions data
43 reported directly through the GHGRP. For 2015 through 2019, EPA took an approach similar to the one used for

²⁷⁸ Only seven gases were aggregated because inclusion of F-GHGs that are not reported in the Inventory results in overestimation of emission factor that is applied to the various non-reporting subpopulations.

1 2011 and 2012 to estimate emissions for the segment of the semiconductor industry that is below EPA's GHGRP
2 reporting threshold, and for R&D facilities, which are not covered by EPA's GHGRP. However, in a change from
3 previous years, EPA was able to develop new annual emission factors for 2015 through 2019 using TMLA from WFF
4 and a more comprehensive set of emissions, i.e., fabs with as well as without abatement control, as new
5 information about the use of abatement in GHGRP fabs and fab-wide were available. Fab-wide DREs represent
6 total fab CO₂ Eq.-weighted controlled F-GHG and N₂O emissions (emissions after the use of abatement) divided by
7 total fab CO₂ Eq.-weighted uncontrolled F-GHG and N₂O emissions (emission prior to the use of abatement).

8 Using information about reported emissions and the use of abatement and fab-wide DREs, EPA was able to
9 calculate uncontrolled emissions (each total F-GHG and N₂O) for every GHGRP reporting fab. Using this, coupled
10 with TMLA estimated using methods described above (see 2011 through 2012), EPA derived emission factors by
11 year, gas type (F-GHG or N₂O), and wafer size (200 mm and less or 300 mm) by dividing the total annual emissions
12 reported by GHGRP reporters by the total TMLA estimated for those reporters. These emission factors were
13 multiplied by estimates of non-reporter TMLA to arrive at estimates of total F-GHG and N₂O emissions for non-
14 reporters for each year. For each wafer size, the total F-GHG emissions were disaggregated into individual gases
15 using the shares of total emissions represented by those gases in the emissions reported to the GHGRP by
16 unabated fabs producing that wafer size.

17 **Data Sources**

18 GHGRP reporters, which consist of former EPA Partners and non-Partners, estimated their emissions using a
19 default emission factor method established by EPA. Like the Tier 2c Method in the *2019 Refinement to the 2006*
20 *IPCC Guidelines*, this method uses different emission and byproduct generation factors for different F-GHGs and
21 process types and uses factors for different wafer sizes (i.e., 300mm vs. 150 and 200mm) and CVD clean subtypes
22 (in situ thermal, in situ plasma, and remote plasma). Starting with 2014 reported emissions, EPA's GHGRP required
23 semiconductor manufacturers to apply updated emission factors to estimate their F-GHG emissions. For the years
24 2011 through 2013 reported emissions, semiconductor manufacturers used older emission factors to estimate
25 their F-GHG emissions (Federal Register / Vol. 75, No. 230 /December 1, 2010, 74829). Subpart I emission factors
26 were updated for 2014 by EPA as a result of a larger set of emission factor data becoming available as part of the
27 Subpart I petition process, which took place from 2011 through 2013.

28 Historically, partners estimated and reported their emissions using a range of methods and uneven
29 documentation. It is assumed that most Partners used a method at least as accurate as the IPCC's Tier 2a
30 Methodology, recommended in the *2006 IPCC Guidelines*. Partners are estimated to have accounted for between
31 56 and 79 percent of F-GHG emissions from U.S. semiconductor manufacturing between 1995 and 2010, with the
32 percentage declining in recent years as Partners increasingly implemented abatement measures.

33 Estimates of operating plant capacities and characteristics for Partners and non-Partners were derived from the
34 Semiconductor Equipment and Materials Industry (SEMI) WFF (formerly World Fab Watch) database (1996 through
35 2012 and 2015) (e.g., Semiconductor Materials and Equipment Industry 2017). Actual worldwide capacity
36 utilizations for 2008 through 2010 were obtained from Semiconductor International Capacity Statistics (SICAS) (SIA
37 2009 through 2011). Estimates of the number of layers for each linewidth was obtained from International
38 Technology Roadmap for Semiconductors: 2013 Edition (Burton and Beizaie 2001; ITRS 2007; ITRS 2008; ITRS 2011;
39 ITRS 2013). PEVM utilized the WFF, SICAS, and ITRS, as well as historical silicon consumption estimates published

1 of the gases are abated (i.e., the maximum value) and that 50 percent is the most likely value and the minimum is
2 zero percent. Consideration of abatement then resulted in four additional industry segments, two 200-mm wafer-
3 processing segments (one fully and one partially abating each gas) and two 300-mm wafer-processing segment
4 (one fully and the other partially abating each gas). Gas-specific emission uncertainties were estimated by
5 convolving the distributions of unabated emissions with the appropriate distribution of abatement efficiency for
6 fully and partially abated facilities using a Monte Carlo simulation.

7 The uncertainty in $E_{R,F-GHG}$ is obtained by allocating the estimates of uncertainties to the total GHGRP-reported
8 emissions from each of the six industry segments, and then running a Monte Carlo simulation which results in the
9 95 percent CI for emissions from GHGRP-reporting facilities ($E_{R,F-GHG}$).

10 The uncertainty in E_{R,N_2O} is obtained by assuming that the uncertainty in the emissions reported by each of the
11 GHGRP reporting facilities results from the uncertainty in quantity of N_2O consumed and the N_2O emission factor
12 (or utilization). Similar to analyses completed for Subpart I (see Technical Support for Modifications to the
13 Fluorinated Greenhouse Gas Emission Estimation Method Option for Semiconductor Facilities under Subpart I,
14 docket EPA-HQ-OAR-2011-0028), the uncertainty of N_2O consumed was assumed to be 20 percent. Consumption
15 of N_2O for GHGRP reporting facilities was estimated by back-calculating from emissions reported and assuming no
16 abatement. The quantity of N_2O utilized (the complement of the emission factor) was assumed to have a triangular
17 distribution with a minimum value of zero percent, mode of 20 percent and maximum value of 84 percent. The
18 minimum was selected based on physical limitations, the mode was set equivalent to the Subpart I default N_2O
19 utilization rate for chemical vapor deposition, and the maximum was set equal to the maximum utilization rate
20 found in ISMI Analysis of Nitrous Oxide Survey Data (ISMI 2009). The inputs were used to simulate emissions for
21 each of the GHGRP reporting, N_2O -emitting facilities. The uncertainty for the total reported N_2O emissions was
22 then estimated by combining the uncertainties of each facilities' reported emissions using Monte Carlo simulation.

23 The estimate of uncertainty in $E_{NR,F-GHG}$ and E_{NR,N_2O} entailed developing estimates of uncertainties for the emissions
24 factors and the corresponding estimates of TMLA.

25 The uncertainty in TMLA depends on the uncertainty of two variables—an estimate of the uncertainty in the
26 average annual capacity utilization for each level of production of fabs (e.g., full scale or R&D production) and a
27 corresponding estimate of the uncertainty in the number of layers manufactured. For both variables, the
28 distributions of capacity utilizations and number of manufactured layers are assumed triangular for all categories
29 of non-reporting fabs. The most probable utilization is assumed to be 82 percent, with the highest and lowest
30 utilization assumed to be 89 percent, and 70 percent, respectively. For the triangular distributions that govern the
31 number of possible layers manufactured, it is assumed the most probable value is one layer less than reported in
32 the ITRS; the smallest number varied by technology generation between one and two layers less than given in the
33 ITRS and largest number of layers corresponded to the figure given in the ITRS.

34 The uncertainty bounds for the average capacity utilization and the number of layers manufactured are used as
35 inputs in a separate Monte Carlo simulation to estimate the uncertainty around the TMLA of both individual
36 facilities as well as the total non-reporting TMLA of each sub-population.

37 The uncertainty around the emission factors for non-reporting facilities is dependent on the uncertainty of the
38 total emissions (MMT CO_2 Eq. units) and the TMLA of each reporting facility in that category. For each wafer size
39 for reporting facilities, total emissions were regressed on TMLA (with an intercept forced to zero) for 10,000
40 emission and 10,000 TMLA values in a Monte Carlo simulation, which results in 10,000 total regression coefficients
41 (emission factors). The 2.5th and the 97.5th percentile of these emission factors are determined, and the bounds
42 are assigned as the percent difference from the estimated emission factor.

43 The final step in estimating the uncertainty in emissions of reporting and non-reporting facilities is convolving the
44 distribution of reported emissions, emission factors, and TMLA using Monte Carlo simulation. For this final Monte
45 Carlo simulation, the distributions of the reported F-GHG gas- and wafer size-specific emissions are assumed to be
46 normally distributed and the uncertainty bounds are assigned at 1.96 standard deviations around the estimated
47 mean. There were some instances, though, where departures from normality were observed for variables, including
48 for the distributions of the gas- and wafer size-specific N_2O emissions, TMLA, and non-reporter emission factors,

1 both for F-GHGs and N₂O. As a result, the distributions for these parameters were assumed to follow a pert beta
 2 distribution.

3 The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-98, which is also
 4 obtained by convolving—using Monte Carlo simulation—the distributions of emissions for each reporting and non-
 5 reporting facility. The emissions estimate for total U.S. F-GHG and N₂O emissions from semiconductor
 6 manufacturing were estimated to be between 4.3 and 4.8 MMT CO₂ Eq. at a 95 percent confidence level. This
 7 range represents 6 percent below to 6 percent above the 2019 emission estimate of 4.6 MMT CO₂ Eq. for
 8 semiconductor emissions for the main seven gases. This range and the associated percentages apply to the
 9 estimate of total emissions rather than those of individual gases. Uncertainties associated with individual gases will
 10 be somewhat higher than the aggregate, but were not explicitly modeled.

11 **Table 4-98: Approach 2 Quantitative Uncertainty Estimates for HFC, PFC, SF₆, NF₃ and N₂O**
 12 **Emissions from Semiconductor Manufacture (MMT CO₂ Eq. and Percent)^a**

Source	Gas	2019 Emission Estimate (MMT CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^b (%)			
			Lower Bound ^c	Upper Bound ^c	Lower Bound	Upper Bound
Semiconductor Manufacture	HFC, PFC, SF ₆ , NF ₃ , and N ₂ O	4.6	4.3	4.8	-6%	6%

^a This uncertainty analysis does not include quantification of the uncertainty of emissions from other F-GHGs for semiconductors, heat transfer fluids, PV, and MEMS.

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

^c Absolute lower and upper bounds were calculated using the corresponding lower and upper bounds in percentages.

13 It should be noted that the uncertainty analysis for this source category does not quantify the uncertainty of HFC,
 14 PFC, and SF₆ emissions from the use of heat transfer fluids or the other F-GHGs. While these emissions are
 15 included in the semiconductor manufacturing F-GHG total emissions, they make up a small portion of total
 16 emissions from the source category (less than 1 percent). Any uncertainty of these emissions would have minimal
 17 impact on the overall uncertainty estimates, and therefore the uncertainties associated for HTF HFC, PFC, and SF₆
 18 emissions was not included in this analysis for this Inventory year.

19 Similarly, the uncertainty was not quantified for emissions from the manufacturing of photovoltaics and micro-
 20 electro-mechanical devices. These emissions make up a small portion of total emissions from the source category.
 21 Any uncertainty of these emissions would have minimal impact on the overall uncertainty estimates, and therefore
 22 associated uncertainties were not included.

23 In an effort to improve the uncertainty analysis for this source category other F-GHGs from semiconductor
 24 manufacturing, HFC, PFC, and SF₆ emissions from the use of heat transfer fluids and manufacturing of PVs and
 25 MEMS may be added in future inventory years (see Planned Improvements section below). The emissions reported
 26 under EPA’s GHGRP for 2014, 2015, 2016, 2017, 2018, and 2019, which are included in the overall emissions
 27 estimates, were based on an updated set of default emission factors.

28 QA/QC and Verification

29 For its GHGRP data, EPA verifies annual facility-level reports through a multi-step process (e.g., including a
 30 combination of pre-and post-submittal electronic checks and manual reviews by staff) to identify potential errors
 31 and ensure that data submitted to EPA are accurate, complete, and consistent (EPA 2015).²⁸⁰ Based on the results
 32 of the verification process, EPA follows up with facilities to resolve mistakes that may have occurred. The post-

²⁸⁰ GHGRP Report Verification Factsheet. <https://www.epa.gov/sites/production/files/2015-07/documents/ghgrp_verification_factsheet.pdf>.

1 submittals checks are consistent with a number of general and category-specific QC procedures including range
2 checks, statistical checks, algorithm checks, and year-to-year checks of reported data and emissions.

3 For more information on the general QA/QC process applied to this source category, consistent with Volume 1,
4 Chapter 6 of the *2006 IPCC Guidelines*, see the QA/QC and Verification Procedures section in the introduction of
5 the IPPU chapter and Annex 8 for more details.

6 Recalculations Discussion

7 Emissions from 2011 through 2019 were updated to reflect updated emissions reporting in EPA's GHGRP, relative
8 to the previous Inventory. Additionally, EPA made the following changes:

- 9 • Previously, capacity utilization numbers used to develop TMLA estimates for 2015 through 2018 were
10 based on utilizations for quarter four of a given year reported to the U.S. Census Bureau. EPA adjusted
11 this approach to take an average utilization as reported across all four quarters of a reporting year. This
12 minimally affected the emission estimates for non-reporters for F-GHGs and N₂O.
- 13 • To estimate non-reporter F-GHG and N₂O emissions, EPA relies on data reported through Subpart I and
14 the World Fab Forecast. This process requires EPA to map facilities that report through Subpart I and
15 which are also represented in the World Fab Forecast. For this inventory update, EPA identified and made
16 corrections to a few instances of this mapping based on new information and additional reviews of the
17 data. This had minimal effects on emission estimates.
- 18 • As discussed in the Methodology section, emission estimates for 2011 and 2012 were recently updated to
19 take into account the revised emission factors used in 2014 and later years. For this inventory update,
20 EPA identified and made corrections to a few instances where the adjusted emissions used in the
21 regression for developing the non-reporter emission factors were recorded incorrectly.
- 22 • EPA updated its approach for adjusting the non-Partner emission factors applied to the 1999-2010 time
23 series to ensure time series consistency. This adjustment is based on a linear interpolation between a
24 PEVM-calculated emission factor from 1999 and an emission factor calculated using 2011 GHGRP-
25 reported data and World Fab Forecast data. EPA updated the 2011 emission factor used to make this
26 adjustment in order to reflect the adjustments made to the 2011 GHGRP reported data in the previous
27 inventory cycle and to ensure time series consistency for data reported through Subpart I. EPA is
28 continuing to evaluate this approach and may make additional improvements per the discussion below.
- 29 • Previously, the capacity used to develop emissions estimates from photovoltaics prior to 2012 was
30 estimated using a linear extrapolation between 0 in 1997 and the known U.S. production capacity in
31 2012. EPA identified a new source of capacity data for 2000 through 2009 and used this data to adjust the
32 estimated emissions between 1997 and 2012. A linear interpolation is now used only for the years
33 between 1997 and 2000, and again between 2009 and 2012.
- 34 • For the Monte Carlo simulations the bounds of TMLA, non-reporter emission factors, and reported N₂O
35 emissions are assumed to follow a pert beta distribution given their asymmetry. Previously, these bounds
36 were assumed to be normally distributed.

37 Planned Improvements

38 The Inventory methodology uses data reported through the EPA Partnership (for earlier years) and EPA's GHGRP
39 (for later years) to extrapolate the emissions of the non-reporting population. While these techniques are well
40 developed, the understanding of the relationship between the reporting and non-reporting populations is limited.
41 Further analysis of the reporting and non-reporting populations could aid in the accuracy of the non-reporting
42 population extrapolation in future years. In addition, the accuracy of the emissions estimates for the non-reporting
43 population could be further increased through EPA's further investigation of and improvement upon the accuracy
44 of estimated activity in the form of TMLA.

1 The Inventory uses utilization from two different sources for various time periods—SEMI to develop PEVM and to
 2 estimate non-Partner emissions for the period 1995 to 2010 and U.S. Census Bureau for 2011 through 2014. SEMI
 3 reported global capacity utilization for manufacturers through 2011. U.S. Census Bureau capacity utilization
 4 include U.S. semiconductor manufacturers as well as assemblers. Further analysis on the impacts of using a new
 5 and different source of utilization data could prove to be useful in better understanding of industry trends and
 6 impacts of utilization data sources on historical emission estimates.

7 The current Inventory now includes HFC, PFC, and SF₆ emissions resulting from the use of heat transfer fluids in the
 8 total estimates of F-GHG emissions from semiconductor manufacturing. A point of consideration for future
 9 Inventory reports is the inclusion of the uncertainty surrounding these emissions in the source category
 10 uncertainty analysis (see also Uncertainty and Time-Series Consistency section).

11 Estimates of non-reporter and non-Partner emissions are based on EPA-developed emission factors for the time
 12 periods pre-2010, 2011 through 2012, and 2015 through 2019. Based on the data available for these time periods,
 13 the methods used to develop emission factors for non-reporters and non-Partners are slightly inconsistent (e.g.,
 14 how data representing emissions and TMLA from the manufacture of various wafer sizes are aggregated or
 15 disaggregated for purposes of calculating emission factors). Further analyses to support potentially adjusting the
 16 methods for developing these emission factors could be done to better ensure consistency across the time series.

17 4.24 Substitution of Ozone Depleting 18 Substances (CRF Source Category 2F)

19 Hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs) are used as alternatives to several classes of ozone-
 20 depleting substances (ODSs) that are being phased out under the terms of the *Montreal Protocol* and the Clean Air
 21 Act Amendments of 1990.²⁸¹ Ozone depleting substances—chlorofluorocarbons (CFCs), halons, carbon
 22 tetrachloride, methyl chloroform, and hydrochlorofluorocarbons (HCFCs)—are used in a variety of industrial
 23 applications including refrigeration and air conditioning equipment, solvent cleaning, foam production,
 24 sterilization, fire extinguishing, and aerosols. Although HFCs and PFCs are not harmful to the stratospheric ozone
 25 layer, they are potent greenhouse gases. Emission estimates for HFCs and PFCs used as substitutes for ODSs are
 26 provided in Table 4-99 and Table 4-100.²⁸²

27 **Table 4-99: Emissions of HFCs and PFCs from ODS Substitutes (MMT CO₂ Eq.)**

Gas	1990	2005	2015	2016	2017	2018	2019
HFC-23	0.0	+	+	+	+	+	+
HFC-32	0.0	0.3	3.9	4.6	5.3	6.0	6.7
HFC-125	+	9.0	43.4	46.9	50.0	53.3	57.8
HFC-134a	+	80.2	73.2	68.8	64.1	61.1	59.8
HFC-143a	+	9.4	27.6	28.2	28.0	27.7	27.8
HFC-236fa	0.0	1.2	1.3	1.3	1.2	1.2	1.1
CF ₄	0.0	+	+	+	+	0.1	0.1
Others ^a	0.2	7.3	14.0	15.0	15.9	16.3	16.4
Total	0.2	107.3	163.6	164.9	164.6	165.6	169.7

Note: Totals may not sum due to independent rounding.

+ Does not exceed 0.05 MMT CO₂ Eq.

^a Others represent an unspecified mix of HFCs and PFCs, which includes HFC-152a, HFC-227ea, HFC-245fa, HFC-365mfc, HFC-43-10mee, HCFO-1233zd(E), HFO-1234yf, HFO-1234ze(E), HFO-1336mzz(Z),

281 [42 U.S.C § 7671, CAA Title VI].

282 Emissions of ODS are not included here consistent with UNFCCC reporting guidelines for national inventories noted in Box 4-1. See Annex 6.2 for more details on emissions of ODS.

C₄F₁₀, and PFC/PFPEs, the latter being a proxy for a diverse collection of PFCs and perfluoropolyethers (PFPEs) employed for solvent applications. For estimating purposes, the GWP value used for PFC/PFPEs was based upon C₆F₁₄.

1 **Table 4-100: Emissions of HFCs and PFCs from ODS Substitution (Metric Tons)**

Gas	1990	2005	2015	2016	2017	2018	2019
HFC-23	0	1	2	2	2	2	2
HFC-32	0	397	5,843	6,801	7,803	8,826	9,885
HFC-125	+	2,580	12,401	13,413	14,289	15,240	16,511
HFC-134a	+	56,052	51,213	48,126	44,797	42,694	41,814
HFC-143a	+	2,093	6,178	6,320	6,264	6,188	6,230
HFC-236fa	0	118	134	129	124	118	112
CF ₄	0	2	6	6	6	7	7
Others ^a	M	M	M	M	M	M	M

+ Does not exceed 0.5 MT.

M (Mixture of Gases).

^a Others represent an unspecified mix of HFCs and PFCs, which includes HFC-152a, HFC-227ea, HFC-245fa, HFC-365mfc, HFC-43-10mee, HCFO-1233zd(E), HFO-1234yf, HFO-1234ze(E), HFO-1336mzz(Z), C₄F₁₀, and PFC/PFPEs, the latter being a proxy for a diverse collection of PFCs and perfluoropolyethers (PFPEs) employed for solvent applications.

2 In 1990 and 1991, the only significant emissions of HFCs and PFCs as substitutes to ODSs were relatively small
 3 amounts of HFC-152a—used as an aerosol propellant and also a component of the refrigerant blend R-500 used in
 4 chillers. Beginning in 1992, HFC-134a was used in growing amounts as a refrigerant in motor vehicle air-
 5 conditioners and in refrigerant blends such as R-404A.²⁸³ In 1993, the use of HFCs in foam production began, and
 6 in 1994 ODS substitutes for halons entered widespread use in the United States as halon production was phased
 7 out. In 1995, these compounds also found applications as solvents.

8 The use and subsequent emissions of HFCs and PFCs as ODS substitutes has been increasing from small amounts in
 9 1990 to 169.7 MMT CO₂ Eq. emitted in 2019. This increase was in large part the result of efforts to phase out CFCs
 10 and other ODSs in the United States. In the short term, this trend is expected to continue, and will likely continue
 11 over the next decade as HCFCs, which are interim substitutes in many applications, are themselves phased-out
 12 under the provisions of the Copenhagen Amendments to the *Montreal Protocol*. Improvements in the technologies
 13 associated with the use of these gases and the introduction of alternative gases and technologies, however, may
 14 help to offset this anticipated increase in emissions.

15 Table 4-101 presents emissions of HFCs and PFCs as ODS substitutes by end-use sector for 1990 through 2019. The
 16 end-use sectors that contributed the most toward emissions of HFCs and PFCs as ODS substitutes in 2019 include
 17 refrigeration and air-conditioning (132.6 MMT CO₂ Eq., or approximately 78 percent), aerosols (16.3 MMT CO₂ Eq.,
 18 or approximately 10 percent), and foams (16.1 MMT CO₂ Eq., or approximately 10 percent). Within the
 19 refrigeration and air-conditioning end-use sector, large retail food was the highest emitting end-use (33.6 MMT
 20 CO₂ Eq.), followed by residential unitary air conditioning. Each of the end-use sectors is described in more detail
 21 below.

22 **Table 4-101: Emissions of HFCs and PFCs from ODS Substitutes (MMT CO₂ Eq.) by Sector**

Sector	1990	2005	2015	2016	2017	2018	2019
Refrigeration/Air Conditioning	+	89.7	124.8	126.5	126.8	128.8	132.6
Aerosols	0.2	10.7	20.8	19.2	17.6	16.0	16.3
Foams	+	4.1	13.9	15.0	15.8	16.2	16.1
Solvents	+	1.7	1.8	1.9	1.9	2.0	2.0

²⁸³ R-404A contains HFC-125, HFC-143a, and HFC-134a.

Fire Protection	+		1.1		2.3	2.4	2.5	2.6	2.8
Total		0.2	107.3		163.6	164.9	164.6	165.6	169.7

Note: Totals may not sum due to independent rounding.

+ Does not exceed 0.05 MMT CO₂ Eq.

Refrigeration/Air Conditioning

The refrigeration and air-conditioning sector includes a wide variety of equipment types that have historically used CFCs or HCFCs. End-uses within this sector include motor vehicle air-conditioning, retail food refrigeration, refrigerated transport (e.g., ship holds, truck trailers, railway freight cars), household refrigeration, residential and small commercial air-conditioning and heat pumps, chillers (large comfort cooling), cold storage facilities, and industrial process refrigeration (e.g., systems used in food processing, chemical, petrochemical, pharmaceutical, oil and gas, and metallurgical industries). As the ODS phaseout has taken effect, most equipment has been retrofitted or replaced to use HFC-based substitutes. Common HFCs in use today in refrigeration/air-conditioning equipment are HFC-134a, R-410A,²⁸⁴ R-404A, and R-507A.²⁸⁵ Lower-GWP options such as hydrofluoroolefin (HFO)-1234yf in motor vehicle air-conditioning, R-717 (ammonia) in cold storage and industrial applications, and R-744 (carbon dioxide) and HFC/HFO blends in retail food refrigeration, are also being used. These refrigerants are emitted to the atmosphere during equipment operation (as a result of component failure, leaks, and purges), as well as at manufacturing (if charged at the factory), installation, servicing, and disposal events.

Aerosols

Aerosol propellants are used in metered dose inhalers (MDIs) and a variety of personal care products and technical/specialty products (e.g., duster sprays and safety horns). Pharmaceutical companies that produce MDIs—a type of inhaled therapy used to treat asthma and chronic obstructive pulmonary disease—have replaced the use of CFCs with HFC-propellant alternatives. The earliest ozone-friendly MDIs were produced with HFC-134a, but the industry is using HFC-227ea as well. Conversely, since the use of CFC propellants was banned in 1978, most non-medical consumer aerosol products have not transitioned to HFCs, but to “not-in-kind” technologies, such as solid or roll-on deodorants and finger-pump sprays. The transition away from ODS in specialty aerosol products has also led to the introduction of non-fluorocarbon alternatives (e.g., hydrocarbon propellants) in certain applications, in addition to HFC-134a or HFC-152a. Other low-GWP options such as HFO-1234ze(E) are being used as well. These propellants are released into the atmosphere as the aerosol products are used.

Foams

Chlorofluorocarbons and HCFCs have traditionally been used as foam blowing agents to produce polyurethane (PU), polystyrene, polyolefin, and phenolic foams, which are used in a wide variety of products and applications. Since the *Montreal Protocol*, flexible PU foams as well as other types of foam, such as polystyrene sheet, polyolefin, and phenolic foam, have transitioned almost completely away from fluorocompounds, into alternatives such as CO₂ and hydrocarbons. The majority of rigid PU foams have transitioned to HFCs—primarily HFC-134a and HFC-245fa. Today, these HFCs are used to produce PU appliance, PU commercial refrigeration, PU spray, and PU panel foams—used in refrigerators, vending machines, roofing, wall insulation, garage doors, and cold storage applications. In addition, HFC-152a, HFC-134a, and CO₂ are used to produce polystyrene sheet/board foam, which is used in food packaging and building insulation. Low-GWP fluorinated foam blowing agents in use include HFO-1234ze(E) and HCFO-1233zd(E). Emissions of blowing agents occur when the foam is manufactured as well as during the foam lifetime and at foam disposal, depending on the particular foam type.

²⁸⁴ R-410A contains HFC-32 and HFC-125.

²⁸⁵ R-507A, also called R-507, contains HFC-125 and HFC-143a.

1 Solvents

2 Chlorofluorocarbons, methyl chloroform (1,1,1-trichloroethane or TCA), and to a lesser extent carbon tetrachloride
3 (CCl₄) were historically used as solvents in a wide range of cleaning applications, including precision, electronics,
4 and metal cleaning. Since their phaseout, metal cleaning end-use applications have primarily transitioned to non-
5 fluorocarbon solvents and not-in-kind processes. The precision and electronics cleaning end-uses have transitioned
6 in part to high-GWP gases, due to their high reliability, excellent compatibility, good stability, low toxicity, and
7 selective solvency. These applications rely on HFC-43-10mee, HFC-365mfc, HFC-245fa, and to a lesser extent, PFCs.
8 Electronics cleaning involves removing flux residue that remains after a soldering operation for printed circuit
9 boards and other contamination-sensitive electronics applications. Precision cleaning may apply to either
10 electronic components or to metal surfaces, and is characterized by products, such as disk drives, gyroscopes, and
11 optical components, that require a high level of cleanliness and generally have complex shapes, small clearances,
12 and other cleaning challenges. The use of solvents yields fugitive emissions of these HFCs and PFCs.

13 Fire Protection

14 Fire protection applications include portable fire extinguishers (“streaming” applications) that originally used halon
15 1211, and total flooding applications that originally used halon 1301, as well as some halon 2402. Since the
16 production and import of virgin halons were banned in the United States in 1994, the halon replacement agent of
17 choice in the streaming sector has been dry chemical, although HFC-236fa is also used to a limited extent. In the
18 total flooding sector, HFC-227ea has emerged as the primary replacement for halon 1301 in applications that
19 require clean agents. Other HFCs, such as HFC-23 and HFC-125, are used in smaller amounts. The majority of HFC-
20 227ea in total flooding systems is used to protect essential electronics, as well as in civil aviation, military mobile
21 weapons systems, oil/gas/other process industries, and merchant shipping. Fluoroketone FK-5-1-12 is also used as
22 a low-GWP option and 2-BTP is being considered. As fire protection equipment is tested or deployed, emissions of
23 HFCs occur.

24 Methodology

25 A detailed Vintaging Model of ODS-containing equipment and products was used to estimate the actual—versus
26 potential—emissions of various ODS substitutes, including HFCs and PFCs. The name of the model refers to the fact
27 that it tracks the use and emissions of various compounds for the annual “vintages” of new equipment that enter
28 service in each end-use. The Vintaging Model predicts ODS and ODS substitute use in the United States based on
29 modeled estimates of the quantity of equipment or products sold each year containing these chemicals and the
30 amount of the chemical required to manufacture and/or maintain equipment and products over time. Emissions
31 for each end-use were estimated by applying annual leak rates and release profiles, which account for the lag in
32 emissions from equipment as they leak over time. By aggregating the data for 78 different end-uses, the model
33 produces estimates of annual use and emissions of each compound. Further information on the Vintaging Model is
34 contained in Annex 3.9.

35 Uncertainty and Time-Series Consistency

36 Given that emissions of ODS substitutes occur from thousands of different kinds of equipment and from millions of
37 point and mobile sources throughout the United States, emission estimates must be made using analytical tools
38 such as the Vintaging Model or the methods outlined in IPCC (2006). Though the model is more comprehensive
39 than the IPCC default methodology, significant uncertainties still exist with regard to the levels of equipment sales,
40 equipment characteristics, and end-use emissions profiles that were used to estimate annual emissions for the
41 various compounds.

42 The uncertainty analysis quantifies the level of uncertainty associated with the aggregate emissions across the 78
43 end-uses in the Vintaging Model. In order to calculate uncertainty, functional forms were developed to simplify
44 some of the complex “vintaging” aspects of some end-use sectors, especially with respect to refrigeration and air-
45 conditioning, and to a lesser degree, fire extinguishing. These sectors calculate emissions based on the entire

lifetime of equipment, not just equipment put into commission in the current year, thereby necessitating simplifying equations. The functional forms used variables that included growth rates, emission factors, transition from ODSs, change in charge size as a result of the transition, disposal quantities, disposal emission rates, and either stock for the current year or original ODS consumption. Uncertainty was estimated around each variable within the functional forms based on expert judgment, and a Monte Carlo analysis was performed.

The most significant sources of uncertainty for this source category include the charge size for technical aerosols using HFC-134a, as well as total stock of refrigerant installed in industrial process refrigeration and cold storage equipment. For this Inventory year, uncertainty was defined for charge sizes of consumer and technical aerosols, which were assumed to be constant in the uncertainty analysis for previous Inventory reports. The updates to the uncertainty analysis for the aerosols sector resulted in increased overall uncertainty for this source category; however, the results reflect a more robust uncertainty analysis for the consumer and technical aerosol end-uses.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-102. Substitution of ozone depleting substances HFC and PFC emissions were estimated to be between 163.6 and 192.8 MMT CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 3.6 percent below to 13.6 percent above the emission estimate of 169.7 MMT CO₂ Eq.

Table 4-102: Approach 2 Quantitative Uncertainty Estimates for HFC and PFC Emissions from ODS Substitutes (MMT CO₂ Eq. and Percent)

Source	Gases	2019 Emission Estimate (MMT CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a (%)			
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Substitution of Ozone Depleting Substances	HFCs and PFCs	169.7	163.6	192.8	-3.6%	+13.6%

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

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

QA/QC and Verification

For more information on the general QA/QC process applied to this source category, consistent with Volume 1, Chapter 6 of the *2006 IPCC Guidelines*, see the QA/QC and Verification Procedures section in the introduction of the IPPU chapter. Category specific QC findings are described below.

Comparison of Reported Consumption to Modeled Consumption of HFCs

Data from EPA’s Greenhouse Gas Reporting Program (GHGRP)²⁸⁶ was also used to perform quality control as a reference scenario check on the modeled emissions from this source category as specified in *2006 IPCC Guidelines for National Greenhouse Gas Inventories*. To do so, consumption patterns demonstrated through data reported under GHGRP Subpart OO—Suppliers of Industrial Greenhouse Gases and Subpart QQ—Importers and Exporters of

²⁸⁶ For the GHGRP data, EPA verifies annual facility-level and company-level reports through a multi-step process (e.g., including a combination of pre-and post-submittal electronic checks and manual reviews by staff) to identify potential errors and ensure that data submitted to EPA are accurate, complete, and consistent (EPA (2015)). Based on the results of the verification process, EPA follows up with facilities to resolve mistakes that may have occurred. The post-submittals checks are consistent with a number of general and category-specific QC procedures, including range checks, statistical checks, algorithm checks, and year-to-year checks of reported data.

1 Fluorinated Greenhouse Gases Contained in Pre-Charged Equipment or Closed-Cell Foams were compared to the
2 modeled demand for new saturated HFCs (excluding HFC-23) used as ODS substitutes from the Vintaging Model.
3 The collection of data from suppliers of HFCs enables EPA to calculate the reporters' aggregated net supply—the
4 sum of the quantities of chemical produced or imported into the United States less the sum of the quantities of
5 chemical transformed (used as a feedstock in the production of other chemicals), destroyed, or exported from the
6 United States.²⁸⁷ This allows for a quality control check on emissions from this source because the Vintaging Model
7 uses modeled demand for new chemical as a proxy for total amount supplied, which is similar to net supply, as an
8 input to the emission calculations in the model.

9 The QA/QC and verification process for individual gases and sources in the Vintaging Model includes regular review
10 against up-to-date market information, including equipment stock estimates, leak rates, and sector transitions. In
11 addition, comparisons against published emission and consumption sources by gas and by source are performed
12 when available, including atmospheric measurements of HFC emissions for the United States and EPA's GHGRP,
13 described further below. Independent peer reviews of the Vintaging Model are periodically performed, including
14 one conducted in 2017 (EPA 2018), to confirm Vintaging Model estimates and identify updates. The HFCs and PFCs
15 within the unspecified mix of HFCs and PFCs are modelled and verified individually in the same process as all other
16 gases and sources in the Vintaging Model. The HFCs and PFCs are grouped in the unspecified mix of HFCs and PFCs
17 category only for the purposes of reporting emissions to protect Confidential Business Information (CBI).

18 *Reported Net Supply (GHGRP Top-Down Estimate)*

19 Under EPA's GHGRP, suppliers (i.e., producers, importers, and exporters) of HFCs under Subpart OO began
20 annually reporting their production, transformation, destruction, imports, and exports to EPA in 2011 (for supply
21 that occurred in 2010) and suppliers of HFCs under Subpart QQ began annually reporting their imports and exports
22 to EPA in 2012 (for supply that occurred in 2011). Beginning in 2015, bulk consumption data for aggregated HFCs
23 reported under Subpart OO were made publicly available under EPA's GHGRP. Data include all saturated HFCs
24 (except HFC-23) reported to EPA across the GHGRP-reporting time series. The data include all 26 such saturated
25 HFCs listed in Table A-1 of 40 CFR Part 98, where regulations for EPA's GHGRP are promulgated, though not all
26 species were reported in each reporting year. For the first time in 2016, net imports of HFCs contained in pre-
27 charged equipment or closed-cell foams reported under Subpart QQ were made publicly available under EPA's
28 GHGRP.

29 *Modeled Consumption (Vintaging Model Bottom-Up Estimate)*

30 The Vintaging Model, used to estimate emissions from this source category, calculates chemical demand based on
31 the quantity of equipment and products sold, serviced and retired each year, and the amount of the chemical
32 required to manufacture and/or maintain the equipment and products.²⁸⁸ It is assumed that the total demand
33 equals the amount supplied by either new production, chemical import, or quantities recovered (usually
34 reclaimed) and placed back on the market. In the Vintaging Model, demand for new chemical, as a proxy for
35 consumption, is calculated as any chemical demand (either for new equipment or for servicing existing equipment)
36 that cannot be met through recycled or recovered material. No distinction is made in the Vintaging Model
37 between whether that need is met through domestic production or imports. To calculate emissions, the Vintaging
38 Model estimates the quantity released from equipment over time. Thus, verifying the Vintaging Model's calculated
39 consumption against GHGRP reported data is one way to check the Vintaging Model's emission estimates.

40 There are eleven saturated HFC species modeled in the Vintaging Model: HFC-23, HFC-32, HFC-125, HFC-134a,
41 HFC-143a, HFC-152a, HFC-227ea, HFC-236fa, HFC-245fa, HFC-365mfc, and HFC-43-10mee. For the purposes of this

²⁸⁷ Chemical that is exported, transformed, or destroyed—unless otherwise imported back to the United States—will never be emitted in the United States.

²⁸⁸ The model builds an inventory of the in-use stock of equipment and products and ODSs and HFCs in each of the sub-applications. Emissions are subsequently estimated by applying annual and disposal emission rates to each population of equipment and products.

1 comparison, only nine HFC species are included (HFC-23 is excluded), to more closely align with the aggregated
 2 total reported under EPA’s GHGRP. While some amounts of less-used saturated HFCs, including isomers of those
 3 included in the Vintaging Model, are reportable under EPA’s GHGRP, the data are believed to represent an amount
 4 comparable to the modeled estimates as a quality control check.

5 *Comparison Results and Discussion*

6 Comparing the estimates of consumption from these two approaches (i.e., reported and modeled) ultimately
 7 supports and improves estimates of emissions, as noted in the *2006 IPCC Guidelines* (which refer to fluorinated
 8 greenhouse gas consumption based on supplies as “potential emissions”):

9 [W]hen considered along with estimates of actual emissions, the potential emissions approach can assist
 10 in validation of completeness of sources covered and as a QC check by comparing total domestic
 11 consumption as calculated in this ‘potential emissions approach’ per compound with the sum of all
 12 activity data of the various uses (IPCC 2006).

13 Table 4-103 and Figure 4-3 compare the published net supply of saturated HFCs (excluding HFC-23) in MMT CO₂
 14 Eq. as determined from Subpart OO (supply of HFCs in bulk) and Subpart QQ (supply of HFCs in products and
 15 foams) of EPA’s GHGRP for the years 2010 through 2019 (EPA 2019) and the chemical demand as calculated by the
 16 Vintaging Model for the same time series.

17 **Table 4-103: U.S. HFC Supply (MMT CO₂ Eq.)**

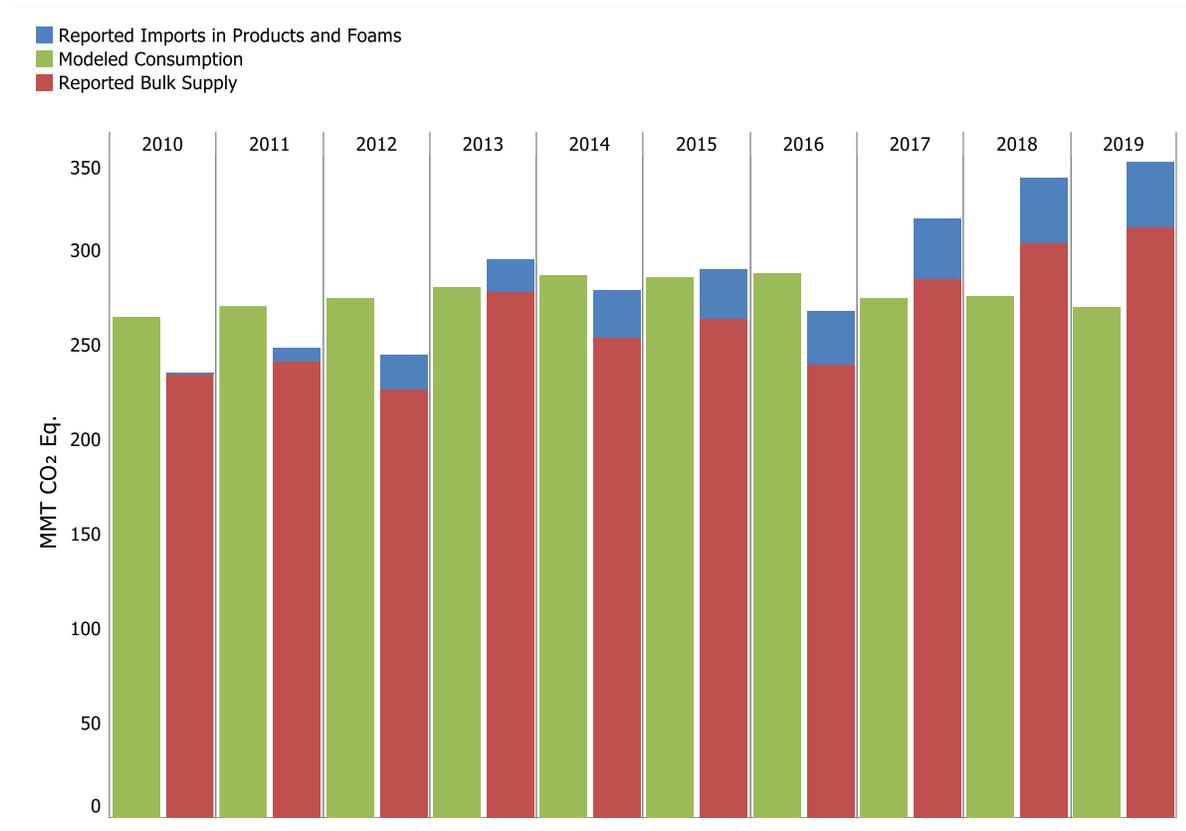
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Reported Net Supply (GHGRP)	235	248	245	295	279	290	268	317	338	324
Industrial GHG Suppliers	235	241	227	278	254	264	240	285	304	294
HFCs in Products and Foams ^a	NA	7	18	17	25	26	28	32	34	30
Modeled Supply (Vintaging Model)	265	271	275	281	287	285	288	275	275	270
Percent Difference	13%	9%	12%	-5%	3%	-2%	7%	-13%	-19%	-17%

18 NA (Not Available)

19 ^a Importers and exporters of fluorinated gases in products were not required to report 2010 data.

20

1 **Figure 4-3: U.S. HFC Consumption**



2
 3 As shown, the estimates from the Vintaging Model are lower than the GHGRP estimates by an average of 1.2
 4 percent across the time series (i.e., 2010 through 2019). Potential reasons for the differences between the
 5 reported and modeled data, include:

- 6 • The Vintaging Model includes fewer saturated HFCs than are reported to EPA’s GHGRP. However, the
 7 additional reported HFCs represent a small fraction of total HFC use for this source category, both in
 8 GWP-weighted and unweighted terms, and as such, it is not expected that the additional HFCs reported to
 9 EPA are a major driver for the difference between the two sets of estimates. To the extent lower-GWP
 10 isomers were used in lieu of the modeled chemicals (e.g., HFC-134 instead of HFC-134a), lower CO₂ Eq.
 11 amounts in the GHGRP data compared to the modeled estimates would be expected.
- 12 • Because the top-down data are reported at the time of actual production or import, and the bottom-up
 13 data are calculated at the time of actual placement on the market, there could be a temporal discrepancy
 14 when comparing data. Because the GHGRP data generally increases over time (although some year-to-
 15 year variations exist) and the Vintaging Model estimates also increase (through 2016), EPA would expect
 16 the modeled estimates to be slightly lower than the corresponding GHGRP data due to this temporal
 17 effect.
- 18 • An additional temporal effect can result from the stockpiling of chemicals by suppliers and distributors.
 19 Suppliers might decide to produce or import additional quantities of HFCs for various reasons such as
 20 expectations that prices may increase or supplies may decrease in the future. Such stockpiling behavior
 21 was seen during ODS phasedowns, but it is unclear if such behavior exists amongst HFC suppliers in
 22 anticipation of potential future controls on HFCs. Any such activity would increase the GHGRP data as
 23 compared to the modeled data. This effect may be a major reason why the GHGRP data in 2017, 2018,
 24 and 2019 are significantly higher than the modeled data.

- Under EPA’s GHGRP, all facilities that produce HFCs are required to report their quantities, whereas importers or exporters of HFCs or pre-charged equipment and closed-cell foams that contain HFCs are only required to report if either their total imports or their total exports of greenhouse gases are greater than or equal to 25,000 metric tons of CO₂ Eq. per year. Thus, some imports may not be accounted for in the GHGRP data. On the other hand, some exports might also not be accounted for in this data.
- In some years, imports and exports may be greater than consumption because the excess is being used to increase chemical or equipment stockpiles as discussed above; in other years, the opposite may hold true. Similarly, relocation of manufacturing facilities or recovery from the recession could contribute to variability in imports or exports. Averaging imports and exports net supplies over multiple years can minimize the impact of such fluctuations. For example, when the 2012 and 2013 net additions to the supply are averaged, as shown in Table 4-104, the percent difference between the consumption estimates decreases compared to the 2012-only and 2013-only estimates.

Table 4-104: Averaged U.S. HFC Demand (MMT CO₂ Eq.)

	2010- 2011 Avg.	2011- 2012 Avg.	2012- 2013 Avg.	2013- 2014 Avg.	2014- 2015 Avg.	2015- 2016 Avg.	2016- 2017 Avg.	2017- 2018 Avg.	2018- 2019 Avg.
Reported Net Supply (GHGRP)	242	247	270	287	285	279	293	328	331
Modeled Demand (Vintaging Model)	268	273	278	284	286	287	281	275	273
Percent Difference	11%	11%	3%	-1%	1%	3%	-4%	-16%	-18%

- The Vintaging Model does not reflect the dynamic nature of reported HFC consumption, with significant differences seen in each year. Whereas the Vintaging Model projects a slowly increasing overall demand through 2016, and a slight lowering after that, actual consumption for specific chemicals or equipment may vary over time and could even switch from positive to negative (indicating more chemical exported, transformed, and destroyed than produced and imported in a given year). Furthermore, consumption as calculated in the Vintaging Model is a function of demand not met by disposal recovery. If, in any given year, a significant number of units are disposed, there will be a large amount of additional recovery in that year that can cause an unexpected and not modeled decrease in demand and thus a decrease in consumption. On the other hand, if market, economic, or other factors cause less than expected disposal and recovery, actual supply would decrease, and hence consumption would increase to meet that demand not satisfied by recovered quantities, increasing the GHGRP amounts.
- The Vintaging Model is used to estimate the emissions that occur in the United States. As such, all equipment or products that contain ODS or alternatives, including saturated HFCs, are assumed to consume and emit chemicals equally as like equipment or products originally produced in the United States. The GHGRP data from Subpart OO (industrial greenhouse gas suppliers) includes HFCs produced or imported and used to fill or manufacture products that are then exported from the United States. The Vintaging Model estimates of demand and supply are not meant to incorporate such chemical. Likewise, chemicals may be used outside the United States to create products or charge equipment that is then imported to and used in the United States. The Vintaging Model estimates of demand and supply are meant to capture this chemical, as it will lead to emissions inside the United States. The GHGRP data from Subpart QQ (supply of HFCs in products) accounts for some of these differences; however, the scope of Subpart QQ does not cover all such equipment or products and the chemical contained therein. Depending on whether the United States is a net importer or net exporter of such chemical, this factor may account for some of the difference shown above or might lead to a further discrepancy.

One factor, however, would only lead to modeled estimates to be even higher than the estimates shown and hence for some years possibly higher than GHGRP data:

- Saturated HFCs are also known to be used as a cover gas in the production of magnesium. The Vintaging Model estimates here do not include the amount of HFCs for this use, but rather only the amount for uses that traditionally were served by ODS. Nonetheless, EPA expects this supply not included in the Vintaging Model estimates to be very small compared to the ODS substitute use for the years analyzed. An indication of the different magnitudes of these categories is seen in the fact that the 2019 emissions from that non-modeled source (0.1 MMT CO₂ Eq.) are much smaller than those for the ODS substitute sector (169.7 MMT CO₂ Eq.).

Using a Tier 2 bottom-up modeling methodology to estimate emissions requires assumptions and expert judgment. Comparing the Vintaging Model's estimates to GHGRP-reported estimates, particularly for more widely used chemicals, can help validate the model but it is expected that the model will have limitations. This comparison shows that Vintaging Model consumption estimates are well within the same order of magnitude as the actual consumption data as reported to EPA's GHGRP although the differences in reported net supply and modeled demand are still significant. Although it can be difficult to capture the observed market variability, the Vintaging Model is periodically reviewed and updated to ensure that the model reflects the current and future trajectory of ODS and ODS substitutes across all end-uses and the Vintaging Model will continue to be compared to available top-down estimates in order to ensure the model accurately estimates HFC consumption and emissions.

Recalculations Discussion

For the current Inventory, updates to the Vintaging Model included:

- Updating market size, substitute transitions, and charge size assumptions for Metered Dose Inhaler (MDI) aerosols to align with stakeholder input and market research (EPA 2020i);
- Replacing the commercial refrigeration foam end-use with ten discrete commercial refrigeration application end-uses:
 - Vending machine foam (EPA 2020h),
 - Stand-alone equipment foam (EPA 2020g),
 - Ice machine foam (EPA 2020f),
 - Refrigerated food processing and dispensing equipment foam (EPA 2020e),
 - Small walk-in cooler foam,
 - Large walk-in cooler foam (EPA 2020a),
 - Display case foam (CFC-11) and display case foam (CFC-12) (EPA 2020b),
 - Road transport foam, and
 - Intermodal container foam (EPA 2020c);
- Updating market transitions for the ice maker end-use based on manufacturer information on refrigerant use (EPA 2020d);
- Adjusting manufacturing emissions for domestic refrigerator foam to only include equipment manufactured within the United States, including those that are produced for export, and excluding those that are imported with foam; and
- Updating market size, manufacturing loss rate, disposal lost rate, and post-life emission rate assumptions for PU and PIR boardstock foams (EPA 2020j).

Together, these updates decreased greenhouse gas emissions on average by 0.7 percent between 1990 and 2018.

Planned Improvements

Future improvements to the Vintaging Model are planned for the Fire Suppression sector. Specifically, streaming agent fire suppression lifetimes, market size, and growth rates are under review to align more closely with real world activities.

4.25 Electrical Transmission and Distribution (CRF Source Category 2G1)

The largest use of sulfur hexafluoride (SF₆), both in the United States and internationally, is as an electrical insulator and interrupter in equipment that transmits and distributes electricity (RAND 2004). The gas has been employed by the electric power industry in the United States since the 1950s because of its dielectric strength and arc-quenching characteristics. It is used in gas-insulated substations, circuit breakers, and other switchgear. SF₆ has replaced flammable insulating oils in many applications and allows for more compact substations in dense urban areas.

Fugitive emissions of SF₆ can escape from gas-insulated substations and switchgear through seals, especially from older equipment. The gas can also be released during equipment manufacturing, installation, servicing, and disposal. Emissions of SF₆ from equipment manufacturing and from electrical transmission and distribution systems were estimated to be 4.2 MMT CO₂ Eq. (0.2 kt) in 2019. This quantity represents an 82 percent decrease from the estimate for 1990 (see Table 4-105 and Table 4-106). There are a few potential causes for this decrease: a sharp increase in the price of SF₆ during the 1990s and a growing awareness of the environmental impact of SF₆ emissions through programs such as EPA's voluntary SF₆ Emission Reduction Partnership for Electric Power Systems (Partnership) and EPA's GHGRP, regulatory drivers at the state and local levels, and research and development of alternative gases to SF₆ that can be used in gas-insulated substations. Utilities participating in the Partnership have lowered their emission factor from 13 percent in 1999 (kg SF₆ emitted per kg of nameplate capacity) to less than 2 percent in 2019. A recent examination of the SF₆ emissions reported by electric power systems to EPA's GHGRP revealed that SF₆ emissions from reporters have decreased by 35 percent from 2011 to 2019,²⁸⁹ with much of the reduction seen from utilities that are not participants in the Partnership. These utilities may be making relatively large reductions in emissions as they take advantage of relatively large and/or inexpensive emission reduction opportunities (i.e., "low hanging fruit," such as replacing major leaking circuit breakers) that Partners have already taken advantage of under the voluntary program (Ottinger et al. 2014). Total emissions from electrical transmission and distribution in 2019 were higher than 2018 emissions, increasing by 8.5 percent. The increase in emissions may be attributed to a combination of increasing nameplate capacity and transmission miles in the United States, and an increase in the average emission rate reported to the GHGRP in 2019.

Table 4-105: SF₆ Emissions from Electric Power Systems and Electrical Equipment Manufacturers (MMT CO₂ Eq.)

Year	Electric Power Systems	Electrical Equipment Manufacturers	Total
1990	22.8	0.3	23.2
2005	7.7	0.7	8.4

²⁸⁹ Analysis of emission trends from facilities reporting to EPA's GHGRP is imperfect due to an inconsistent group of reporters year to year. A facility that has reported total non-biogenic greenhouse gas emissions below 15,000 metric tons of carbon dioxide equivalent (MT CO₂ Eq.) for three consecutive years or below 25,000 MT CO₂ Eq. for five consecutive years to EPA's GHGRP can discontinue reporting for all direct emitter subparts. For this sector, most of the variability in the group of reporters is due to facilities exiting the GHGRP due to being below one of these thresholds; however, facilities must re-enter the program if their emissions at a later date are above 25,000 MT CO₂ Eq., which may occur for a variety of reasons, including changes in facility size and changes in emission rates.

2015	3.5	0.3	3.8
2016	3.8	0.3	4.1
2017	3.8	0.3	4.2
2018	3.6	0.3	3.9
2019	3.9	0.3	4.2

Note: Totals may not sum due to independent rounding.

1 **Table 4-106: SF₆ Emissions from Electric Power Systems and Electrical Equipment**
 2 **Manufacturers (kt)**

Year	Emissions
1990	1.0
2005	0.4
2015	0.2
2016	0.2
2017	0.2
2018	0.2
2019	0.2

3 Methodology

4 The estimates of emissions from Electrical Transmission and Distribution are comprised of emissions from electric
 5 power systems and emissions from the manufacture of electrical equipment. The methodologies for estimating
 6 both sets of emissions are described below.

7 1990 through 1998 Emissions from Electric Power Systems

8 Emissions from electric power systems from 1990 through 1998 were estimated based on (1) the emissions
 9 estimated for this source category in 1999, which, as discussed in the next section, were based on the emissions
 10 reported during the first year of EPA's SF₆ Emission Reduction Partnership for Electric Power Systems (Partnership),
 11 and (2) the RAND survey of global SF₆ emissions. Because most utilities participating in the Partnership reported
 12 emissions only for 1999 through 2011, modeling was used to estimate SF₆ emissions from electric power systems
 13 for the years 1990 through 1998. To perform this modeling, U.S. emissions were assumed to follow the same
 14 trajectory as global emissions from this source during the 1990 to 1999 period. To estimate global emissions, the
 15 RAND survey of global SF₆ sales was used, together with the following equation for estimating emissions, which is
 16 derived from the mass-balance equation for chemical emissions (Volume 3, Equation 7.3) in the *2006 IPCC*
 17 *Guidelines*.²⁹⁰ (Although Equation 7.3 of the *2006 IPCC Guidelines* appears in the discussion of substitutes for
 18 ozone-depleting substances, it is applicable to emissions from any long-lived pressurized equipment that is
 19 periodically serviced during its lifetime.)

20 Emissions (kilograms SF₆) = SF₆ purchased to refill existing equipment (kilograms) + nameplate capacity of retiring
 21 equipment (kilograms)²⁹¹

²⁹⁰ Ideally, sales to utilities in the United States between 1990 and 1999 would be used as a model. However, this information was not available. There were only two U.S. manufacturers of SF₆ during this time period, so it would not have been possible to conceal sensitive sales information by aggregation.

²⁹¹ Nameplate capacity is defined as the amount of SF₆ within fully charged electrical equipment.

1 Note that the above equation holds whether the gas from retiring equipment is released or recaptured; if the gas
2 is recaptured, it is used to refill existing equipment, thereby lowering the amount of SF₆ purchased by utilities for
3 this purpose.

4 Gas purchases by utilities and equipment manufacturers from 1961 through 2003 are available from the RAND
5 (2004) survey. To estimate the quantity of SF₆ released or recovered from retiring equipment, the nameplate
6 capacity of retiring equipment in a given year was assumed to equal 81.2 percent of the amount of gas purchased
7 by electrical equipment manufacturers 40 years previous (e.g., in 2000, the nameplate capacity of retiring
8 equipment was assumed to equal 81.2 percent of the gas purchased in 1960). The remaining 18.8 percent was
9 assumed to have been emitted at the time of manufacture. The 18.8 percent emission factor is an average of IPCC
10 default SF₆ emission rates for Europe and Japan for 1995 (IPCC 2006). The 40-year lifetime for electrical equipment
11 is also based on IPCC (2006). The results of the two components of the above equation were then summed to yield
12 estimates of global SF₆ emissions from 1990 through 1999.

13 U.S. emissions between 1990 and 1999 are assumed to follow the same trajectory as global emissions during this
14 period. To estimate U.S. emissions, global emissions for each year from 1990 through 1998 were divided by the
15 estimated global emissions from 1999. The result was a time series of factors that express each year's global
16 emissions as a multiple of 1999 global emissions. Historical U.S. emissions were estimated by multiplying the factor
17 for each respective year by the estimated U.S. emissions of SF₆ from electric power systems in 1999 (estimated to
18 be 13.6 MMT CO₂ Eq.).

19 Two factors may affect the relationship between the RAND sales trends and actual global emission trends. One is
20 utilities' inventories of SF₆ in storage containers. When SF₆ prices rise, utilities are likely to deplete internal
21 inventories before purchasing new SF₆ at the higher price, in which case SF₆ sales will fall more quickly than
22 emissions. On the other hand, when SF₆ prices fall, utilities are likely to purchase more SF₆ to rebuild inventories, in
23 which case sales will rise more quickly than emissions. This effect was accounted for by applying 3-year smoothing
24 to utility SF₆ sales data. The other factor that may affect the relationship between the RAND sales trends and
25 actual global emissions is the level of imports from and exports to Russia and China. SF₆ production in these
26 countries is not included in the RAND survey and is not accounted for in any another manner by RAND. However,
27 atmospheric studies confirm that the downward trend in estimated global emissions between 1995 and 1998 was
28 real (see the Uncertainty discussion below).

29 **1999 through 2019 Emissions from Electric Power Systems**

30 Emissions from electric power systems from 1999 to 2019 were estimated based on: (1) reporting from utilities
31 participating in EPA's SF₆ Emission Reduction Partnership for Electric Power Systems (Partners), which began in
32 1999; (2) reporting from utilities covered by EPA's GHGRP, which began in 2012 for emissions occurring in 2011
33 (GHGRP-Only Reporters); and (3) the relationship between utilities' reported emissions and their transmission
34 miles as reported in the 2001, 2004, 2007, 2010, 2013, and 2016 Utility Data Institute (UDI) Directories of Electric
35 Power Producers and Distributors (UDI 2001, 2004, 2007, 2010, 2013, and 2017), which was applied to the electric
36 power systems that do not report to EPA (Non-Reporters). (Transmission miles are defined as the miles of lines
37 carrying voltages above 34.5 kV).

38 **Partners**

39 Over the period from 1999 to 2019, Partner utilities, which for inventory purposes are defined as utilities that
40 either currently are or previously have been part of the Partnership,²⁹² represented 49 percent, on average, of
41 total U.S. transmission miles. Partner utilities estimated their emissions using a Tier 3 utility-level mass balance
42 approach (IPCC 2006). If a Partner utility did not provide data for a particular year, emissions were interpolated
43 between years for which data were available or extrapolated based on Partner-specific transmission mile growth

²⁹² Starting in the 1990 to 2015 Inventory, partners who had reported three years or less of data prior to 2006 were removed. Most of these Partners had been removed from the list of current Partners but remained in the Inventory due to the extrapolation methodology for non-reporting partners.

1 rates. In 2012, many Partners began reporting their emissions (for 2011 and later years) through EPA’s GHGRP
2 (discussed further below) rather than through the Partnership. In 2019, approximately 1 percent of the total
3 emissions attributed to Partner utilities were reported through Partnership reports. Approximately 96 percent of
4 the total emissions attributed to Partner utilities were reported and verified through EPA’s GHGRP. Partners
5 without verified 2019 data accounted for approximately 3 percent of the total emissions attributed to Partner
6 utilities.²⁹³

7 The GHGRP program has an “offramp” provision (40 CFR Part 98.2(i)) that exempts facilities from reporting under
8 certain conditions. If reported total greenhouse gas emissions are below 15,000 metric tons of carbon dioxide
9 equivalent (MT CO₂ Eq.) for three consecutive years or below 25,000 MT CO₂ Eq. for five consecutive years, the
10 facility may elect to discontinue reporting. GHGRP reporters that have off-ramped are extrapolated for three years
11 of non-reporting using a utility-specific transmission mile growth rate. After three consecutive years of non-
12 reporting, they are treated as non-reporters, as described in the section below on non-reporters. Partners that
13 have years of non-reporting between reporting years are gap filled by interpolating between reported values.

14 ***GHGRP-Only Reporters***

15 EPA’s GHGRP requires users of SF₆ in electric power systems to report emissions if the facility has a total SF₆
16 nameplate capacity that exceeds 17,820 pounds. (This quantity is the nameplate capacity that would result in
17 annual SF₆ emissions equal to 25,000 metric tons of CO₂ equivalent at the historical emission rate reported under
18 the Partnership.) As under the Partnership, electric power systems that report their SF₆ emissions under EPA’s
19 GHGRP are required to use the Tier 3 utility-level mass-balance approach. Many Partners began reporting their
20 emissions through EPA’s GHGRP in 2012 (reporting emissions for 2011 and later years) because their nameplate
21 capacity exceeded the reporting threshold. Some Partners who did not report through EPA’s GHGRP continued to
22 report through the Partnership.

23 In addition, many non-Partners began reporting to EPA for the first time through its GHGRP in 2012. Non-Partner
24 emissions reported and verified under EPA’s GHGRP were compiled to form a new category of reported data
25 (GHGRP-Only Reporters). GHGRP-Only Reporters accounted for 21 percent of U.S. transmission miles and 24
26 percent of estimated U.S. emissions from electric power system in 2019.²⁹⁴

27 Emissions for GHGRP-only reporters that off-ramp are extrapolated for three years of non-reporting using a utility-
28 specific transmission mile growth rate. After three consecutive years of non-reporting, they are treated as non-
29 reporters, and emissions are subsequently estimated based on the methodology described below.

30 ***Non-Reporters***

31 Emissions from Non-Reporters (i.e., utilities other than Partners and GHGRP-Only Reporters) in every year since
32 1999 were estimated using the results of a regression analysis that correlated emissions from reporting utilities
33 (using verified data from both Partners and GHGRP-Only Reporters) with their transmission miles.²⁹⁵ As noted
34 above, non-Partner emissions were reported to the EPA for the first time through its GHGRP in 2012 (representing
35 2011 emissions). This set of reported data was of particular interest because it provided insight into the emission

²⁹³ Only data reported as of September 28, 2020 are used in the emission estimates for the prior year of reporting. Emissions for Partners that did not report to the Partnership or GHGRP are extrapolated for three years using a utility-specific transmission mile growth rate. After four consecutive years of non-reporting they are included in the ‘non-reporting Partners’ category. It should be noted that data reported through EPA’s GHGRP must go through a verification process. For electric power systems, verification involved a series of electronic range, completeness, and algorithm checks for each report submitted.

²⁹⁴ GHGRP-reported and Partner transmission miles from a number of facilities were equal to zero with non-zero emissions. These facilities emissions were added to the emissions totals for their respective parent companies when identifiable and not included in the regression equation when not identifiable or applicable. Other facilities reported non-zero transmission miles with zero emissions, or zero transmission miles and zero emissions. These facilities were not included in the development of the regression equations (discussed further below). These emissions are already implicitly accounted for in the relationship between transmission miles and emissions.

²⁹⁵ In the United States, SF₆ is contained primarily in transmission equipment rated above 34.5 kV.

rate of non-Partners, which previously was assumed to be equal to the historical (1999) emission rate of Partners. Specifically, emissions were estimated for Non-Reporters as follows:

- **Non-Reporters, 1999 to 2011:** First, the 2011 emission rates (per kg nameplate capacity and per transmission mile) reported by Partners and GHGRP-Only Reporters were reviewed to determine whether there was a statistically significant difference between these two groups. Transmission mileage data for 2011 was reported through GHGRP, with the exception of transmission mileage data for Partners that did not report through GHGRP, which was obtained from UDI. It was determined that there is no statistically significant difference between the emission rates of Partners and GHGRP-Only reporters; therefore, Partner and GHGRP-Only reported data for 2011 were combined to develop regression equations to estimate the emissions of Non-Reporters. Historical emissions from Non-Reporters were estimated by linearly interpolating between the 1999 regression coefficient (based on 1999 Partner data) and the 2011 regression coefficient.
- **Non-Reporters, 2012 to Present:** It was determined that there continued to be no statistically significant difference between the emission rates reported by Partners and by GHGRP-Only Reporters. Therefore, the emissions data from both groups were combined to develop regression equations for 2012. This was repeated for 2013 through 2019 using Partner and GHGRP-Only Reporter data for each year.
 - The 2019 regression equation for reporters was developed based on the emissions reported by a subset of Partner utilities and GHGRP-Only utilities who reported non-zero emissions and non-zero transmission miles (representing approximately 65 percent of total U.S. transmission miles). The regression equation for 2019 is:

$$\text{Emissions (kg)} = 0.226 \times \text{Transmission Miles}$$

Table 4-107 below shows the percentage of transmission miles covered by reporters (i.e., associated with reported data) and the regression coefficient for 1999 (the first year data was reported), and for 2011 through present (the years with GHGRP reported data). The coefficient increased between 2015 and 2019.

Table 4-107: Transmission Mile Coverage (Percent) and Regression Coefficients (kg per mile)

	1999	2005	2015	2016	2017	2018	2019
Percentage of Miles Covered by Reporters	50%	50%	73%	73%	74%	70%	65%
Regression Coefficient^a	0.71	0.35	0.19	0.21	0.24	0.21	0.23

^a Regression coefficient for emissions is calculated utilizing transmission miles as the explanatory variable and emissions as the response variable. The equation utilizes a constant intercept of zero. When calculating the regression coefficient, outliers are also removed from the analysis when the standard residual for that reporter exceeds the value 3.0.

Data on transmission miles for each Non-Reporter for the years 2000, 2003, 2006, and 2009, 2012, and 2016 were obtained from the 2001, 2004, 2007, 2010, 2013, and 2017 UDI Directories of Electric Power Producers and Distributors, respectively (UDI 2001, 2004, 2007, 2010, 2013, and 2017). The following trends in transmission miles have been observed over the time series:

- The U.S. transmission system grew by over 22,000 miles between 2000 and 2003 yet declined by almost 4,000 miles between 2003 and 2006. Given these fluctuations, periodic increases are assumed to occur gradually. Therefore, transmission mileage was assumed to increase at an annual rate of 1.2 percent between 2000 and 2003 and decrease by 0.20 percent between 2003 and 2006.
- The U.S. transmission system’s annual growth rate grew to 1.7 percent from 2006 to 2009 as transmission miles increased by more than 33,000 miles.
- The annual growth rate for 2009 through 2012 was calculated to be 1.5 percent as transmission miles grew yet again by over 30,000 miles during this time period.
- The annual transmission mile growth rate for 2012 through 2019 was calculated to be 0.6 percent, as transmission miles increased by approximately 43,000 miles.

1 Transmission miles for each year for non-reporters were calculated by interpolating between UDI reported values
2 obtained from the 2001, 2004, 2007, 2010, 2013 and 2017 UDI directories. In cases where a non-reporter
3 previously reported the GHGRP or the Partnership, transmission miles were interpolated between the most
4 recently reported value and the next available UDI value.

5 **Total Industry Emissions**

6 As a final step, total electric power system emissions from 1999 through 2019 were determined for each year by
7 summing the Partner reported and estimated emissions (reported data was available through the EPA's SF₆
8 Emission Reduction Partnership for Electric Power Systems), the GHGRP-only reported emissions, and the non-
9 reporting utilities' emissions (determined using the regression equations).

10 **1990 through 2019 Emissions from Manufacture of Electrical Equipment**

11 Three different methods were used to estimate 1990 to 2019 emissions from original electrical equipment
12 manufacturers (OEMs).

- 13 • OEM emissions from 1990 through 2000 were derived by assuming that manufacturing emissions equaled
14 10 percent of the quantity of SF₆ provided with new equipment. The 10 percent emission rate is the
15 average of the "ideal" and "realistic" manufacturing emission rates (4 percent and 17 percent,
16 respectively) identified in a paper prepared under the auspices of the International Council on Large
17 Electric Systems (CIGRE) in February 2002 (O'Connell et al. 2002). The quantity of SF₆ provided with new
18 equipment was estimated based on statistics compiled by the National Electrical Manufacturers
19 Association (NEMA). These statistics were provided for 1990 to 2000.
- 20 • OEM emissions from 2000 through 2010 were estimated by (1) interpolating between the emission rate
21 estimated for 2000 (10 percent) and an emission rate estimated for 2011 based on reporting by OEMs
22 through the GHGRP (5.7 percent), and (2) estimating the quantities of SF₆ provided with new equipment
23 for 2001 to 2010. The quantities of SF₆ provided with new equipment were estimated using Partner
24 reported data and the total industry SF₆ nameplate capacity estimate (156.5 MMT CO₂ Eq. in 2010).
25 Specifically, the ratio of new nameplate capacity to total nameplate capacity of a subset of Partners for
26 which new nameplate capacity data was available from 1999 to 2010 was calculated. These ratios were
27 then multiplied by the total industry nameplate capacity estimate for each year to derive the amount of
28 SF₆ provided with new equipment for the entire industry. Additionally, to obtain the 2011 emission rate
29 (necessary for estimating 2001 through 2010 emissions), the estimated 2011 emissions (estimated using
30 the third methodology listed below) were divided by the estimated total quantity of SF₆ provided with
31 new equipment in 2011. The 2011 quantity of SF₆ provided with new equipment was estimated in the
32 same way as the 2001 through 2010 quantities.
- 33 • OEM emissions from 2011 through 2019 were estimated using the SF₆ emissions from OEMs reporting to
34 the GHGRP, and an assumption that these reported emissions account for a conservatively low estimate
35 of 50 percent of the total emissions from all U.S. OEMs.

36 **Uncertainty and Time-Series Consistency**

37 To estimate the uncertainty associated with emissions of SF₆ from Electrical Transmission and Distribution,
38 uncertainties associated with four quantities were estimated: (1) emissions from Partners, (2) emissions from
39 GHGRP-Only Reporters, (3) emissions from Non-Reporters, and (4) emissions from manufacturers of electrical
40 equipment. A Monte Carlo analysis was then applied to estimate the overall uncertainty of the emissions estimate.

41 Total emissions from the SF₆ Emission Reduction Partnership include emissions from both reporting (through the
42 Partnership or EPA's GHGRP) and non-reporting Partners. For reporting Partners, individual Partner-reported SF₆
43 data was assumed to have an uncertainty of 10 percent. Based on a Monte Carlo analysis, the cumulative
44 uncertainty of all Partner-reported data was estimated to be 6.0 percent. The uncertainty associated with
45 extrapolated or interpolated emissions from non-reporting Partners was assumed to be 20 percent.

1 For GHGRP-Only Reporters, reported SF₆ data was assumed to have an uncertainty of 20 percent.²⁹⁶ Based on a
 2 Monte Carlo analysis, the cumulative uncertainty of all GHGRP-Only reported data was estimated to be 8.5
 3 percent.

4 There are two sources of uncertainty associated with the regression equations used to estimate emissions in 2019
 5 from Non-Reporters: (1) uncertainty in the coefficients (as defined by the regression standard error estimate), and
 6 (2) the uncertainty in total transmission miles for Non-Reporters. Uncertainties were also estimated regarding (1)
 7 estimates of SF₆ emissions from OEMs reporting to EPA’s GHGRP, and (2) the assumption on the percent share of
 8 OEM emissions from OEMs reporting to EPA’s GHGRP.

9 The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-108. Electrical
 10 Transmission and Distribution SF₆ emissions were estimated to be between 3.6 and 5.0 MMT CO₂ Eq. at the 95
 11 percent confidence level. This indicates a range of approximately 16 percent below and 18 percent above the
 12 emission estimate of 4.2 MMT CO₂ Eq.

13 **Table 4-108: Approach 2 Quantitative Uncertainty Estimates for SF₆ Emissions from**
 14 **Electrical Transmission and Distribution (MMT CO₂ Eq. and Percent)**

Source	Gas	2019 Emission Estimate (MMT CO ₂ Eq.)	Uncertainty Range Relative to 2018 Emission Estimate ^a			
			Lower Bound	Upper Bound	Lower Bound (%)	Upper Bound (%)
Electrical Transmission and Distribution	SF ₆	4.2	3.6	5.0	-16%	+18%

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

15 In addition to the uncertainty quantified above, there is uncertainty associated with using global SF₆ sales data to
 16 estimate U.S. emission trends from 1990 through 1999. However, the trend in global emissions implied by sales of
 17 SF₆ appears to reflect the trend in global emissions implied by changing SF₆ concentrations in the atmosphere. That
 18 is, emissions based on global sales declined by 29 percent between 1995 and 1998 (RAND 2004), and emissions
 19 based on atmospheric measurements declined by 17 percent over the same period (Levin et al. 2010).

20 Several pieces of evidence indicate that U.S. SF₆ emissions were reduced as global emissions were reduced. First,
 21 the decreases in sales and emissions coincided with a sharp increase in the price of SF₆ that occurred in the mid-
 22 1990s and that affected the United States as well as the rest of the world. A representative from DILO, a major
 23 manufacturer of SF₆ recycling equipment, stated that most U.S. utilities began recycling rather than venting SF₆
 24 within two years of the price rise. Finally, the emissions reported by the one U.S. utility that reported its emissions
 25 for all the years from 1990 through 1999 under the Partnership showed a downward trend beginning in the mid-
 26 1990s.

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

30 QA/QC and Verification

31 For the GHGRP data, EPA verifies annual facility-level reports through a multi-step process (e.g., including a
 32 combination of pre-and post-submittal electronic checks and manual reviews by staff) to identify potential errors

²⁹⁶ Uncertainty is assumed to be higher for the GHGRP-Only category, because 2011 is the first year that those utilities have reported to EPA.

1 and ensure that data submitted to EPA are accurate, complete, and consistent (EPA 2015).²⁹⁷ Based on the results
2 of the verification process, EPA follows up with facilities to resolve mistakes that may have occurred. The post-
3 submittals checks are consistent with a number of general and category-specific QC procedures including: range
4 checks, statistical checks, algorithm checks, and year-to-year checks of reported data and emissions.

5 For more information on the general QA/QC process applied to this source category, consistent with Volume 1,
6 Chapter 6 of the *2006 IPCC Guidelines*, see the QA/QC and Verification Procedures section in the introduction of
7 the IPPU chapter and Annex 8 for more details.

8 Recalculations Discussion

9 The historical emissions estimated for this source category have undergone the following revisions for the period
10 1990 through 2018.

- 11 • **GHGRP report resubmissions:** Historical estimates for the period 2011 through 2018 were updated
12 relative to the previous report based on revisions to reported historical data in EPA's GHGRP.

13 As a result of the recalculations, SF₆ emissions from electrical transmission and distribution decreased by 3.9
14 percent for 2018 relative to the previous report, and SF₆ nameplate capacity decreased by 0.3 percent for 2018
15 relative to the previous report. On average, SF₆ emission estimates for the entire time series decreased by
16 approximately 0.1 percent per year.

17 Planned Improvements

18 EPA plans to more closely examine transmission miles data by company provided by the UDI data sets, which has
19 been historically purchased every three years, to identify inconsistencies in the companies included in the data
20 sets and improve the transmission mile estimates to address data gaps, as necessary. In future inventory years,
21 EPA plans to identify additional sources for transmission miles data by company due to a discontinuation of this
22 specific data set in 2017.

23 Additionally, as the information on the type of new and retiring equipment is collected through GHGRP reporting,
24 EPA expects this data to provide insight into the relative importance of the two types of equipment as potential
25 emission sources. Historically, hermetically sealed pressure equipment has been considered to be a relatively small
26 source of SF₆ in the United States; however, better estimating its potential source of emissions upon end-of-life
27 (i.e., disposal emissions) is an area for further analysis.

28 EPA also plans to investigate ways in which the electric transmission and distribution sector estimates can be
29 disaggregated to state level emissions estimates in order to provide greater clarity and specificity in emissions
30 rates by region.

31 4.26 Nitrous Oxide from Product Uses (CRF 32 Source Category 2G3)

33 Nitrous oxide (N₂O) is a clear, colorless, oxidizing liquefied gas with a slightly sweet odor which is used in a wide
34 variety of specialized product uses and applications. The amount of N₂O that is actually emitted depends upon the
35 specific product use or application.

²⁹⁷ GHGRP Report Verification Factsheet. <https://www.epa.gov/sites/production/files/2015-07/documents/ghgrp_verification_factsheet.pdf>.

1 There are a total of three N₂O production facilities currently operating in the United States (Ottinger 2020). Nitrous
 2 oxide is primarily used in carrier gases with oxygen to administer more potent inhalation anesthetics for general
 3 anesthesia, and as an anesthetic in various dental and veterinary applications. The second main use of N₂O is as a
 4 propellant in pressure and aerosol products, the largest application being pressure-packaged whipped cream.
 5 Small quantities of N₂O also are used in the following applications:

- 6 • Oxidizing agent and etchant used in semiconductor manufacturing;
- 7 • Oxidizing agent used, with acetylene, in atomic absorption spectrometry;
- 8 • Production of sodium azide, which is used to inflate airbags;
- 9 • Fuel oxidant in auto racing; and
- 10 • Oxidizing agent in blowtorches used by jewelers and others (Heydorn 1997).

11 Production of N₂O in 2019 was approximately 15 kt (see Table 4-109).

12 **Table 4-109: N₂O Production (kt)**

Year	kt
1990	16
2005	15
2015	15
2016	15
2017	15
2018	15
2019	15

13 Nitrous oxide emissions were 4.2 MMT CO₂ Eq. (14 kt N₂O) in 2019 (see Table 4-110). Production of N₂O stabilized
 14 during the 1990s because medical markets had found other substitutes for anesthetics, and more medical
 15 procedures were being performed on an outpatient basis using local anesthetics that do not require N₂O. The use
 16 of N₂O as a propellant for whipped cream has also stabilized due to the increased popularity of cream products
 17 packaged in reusable plastic tubs (Heydorn 1997).

18 **Table 4-110: N₂O Emissions from N₂O Product Usage (MMT CO₂ Eq. and kt)**

Year	MMT CO ₂ Eq.	kt
1990	4.2	14
2005	4.2	14
2015	4.2	14
2016	4.2	14
2017	4.2	14
2018	4.2	14
2019	4.2	14

19 Methodology

20 Emissions from N₂O product uses were estimated using the following equation:

$$21 \quad E_{pu} = \sum_a (P \times S_a \times ER_a)$$

22 where,

- 23 E_{pu} = N₂O emissions from product uses, metric tons
 24 P = Total U.S. production of N₂O, metric tons

1	a	=	specific application
2	S _a	=	Share of N ₂ O usage by application <i>a</i>
3	ER _a	=	Emission rate for application <i>a</i> , percent

4 The share of total quantity of N₂O usage by end-use represents the share of national N₂O produced that is used by
5 the specific subcategory (e.g., anesthesia, food processing). In 2019, the medical/dental industry used an
6 estimated 89.5 percent of total N₂O produced, followed by food processing propellants at 6.5 percent. All other
7 subcategories, including semiconductor manufacturing, atomic absorption spectrometry, sodium azide production,
8 auto racing, and blowtorches, used the remainder of the N₂O produced. This subcategory breakdown has changed
9 only slightly over the past decade. For instance, the small share of N₂O usage in the production of sodium azide
10 declined significantly during the 1990s. Due to the lack of information on the specific time period of the phase-out
11 in this market subcategory, most of the N₂O usage for sodium azide production is assumed to have ceased after
12 1996, with the majority of its small share of the market assigned to the larger medical/dental consumption
13 subcategory (Heydorn 1997). For 1990 through 1996, N₂O usage was allocated across the following categories:
14 medical applications, food processing propellant, and sodium azide production. A usage emissions rate was then
15 applied for each sector to estimate the amount of N₂O emitted.

16 Only the medical/dental and food propellant subcategories were estimated to release emissions into the
17 atmosphere that are not captured under another source category, and therefore these subcategories were the
18 only usage subcategories with emission rates. Emissions of N₂O from semiconductor manufacturing are described
19 in Section 4.23 Electronics Industry (CRF Source Category 2E) and reported under CRF Source Category 2H3. For
20 the medical/dental subcategory, due to the poor solubility of N₂O in blood and other tissues, none of the N₂O is
21 assumed to be metabolized during anesthesia and quickly leaves the body in exhaled breath. Therefore, an
22 emission factor of 100 percent was used for this subcategory (IPCC 2006). For N₂O used as a propellant in
23 pressurized and aerosol food products, none of the N₂O is reacted during the process and all of the N₂O is emitted
24 to the atmosphere, resulting in an emission factor of 100 percent for this subcategory (IPCC 2006). For the
25 remaining subcategories, all of the N₂O is consumed or reacted during the process, and therefore the emission rate
26 was considered to be zero percent (Tupman 2003).

27 The 1990 through 1992 N₂O production data were obtained from SRI Consulting's *Nitrous Oxide, North America*
28 (Heydorn 1997). Nitrous oxide production data for 1993 through 1995 were not available. Production data for
29 1996 was specified as a range in two data sources (Heydorn 1997; Tupman 2003). In particular, for 1996, Heydorn
30 (1997) estimates N₂O production to range between 13.6 and 18.1 thousand metric tons. Tupman (2003) provided a
31 narrower range (15.9 to 18.1 thousand metric tons) for 1996 that falls within the production bounds described by
32 Heydorn (1997). Tupman (2003) data are considered more industry-specific and current; therefore, the midpoint
33 of the narrower production range was used to estimate N₂O emissions for years 1993 through 2001 (Tupman
34 2003). The 2002 and 2003 N₂O production data were obtained from the Compressed Gas Association Nitrous
35 Oxide Fact Sheet and Nitrous Oxide Abuse Hotline (CGA 2002, 2003). These data were also provided as a range. For
36 example, in 2003, CGA (2003) estimates N₂O production to range between 13.6 and 15.9 thousand metric tons.
37 Due to the unavailability of data, production estimates for years 2004 through 2019 were held constant at the
38 2003 value.

39 The 1996 share of the total quantity of N₂O used by each subcategory was obtained from SRI Consulting's *Nitrous*
40 *Oxide, North America* (Heydorn 1997). The 1990 through 1995 share of total quantity of N₂O used by each
41 subcategory was kept the same as the 1996 number provided by SRI Consulting. The 1997 through 2001 share of
42 total quantity of N₂O usage by sector was obtained from communication with a N₂O industry expert (Tupman
43 2003). The 2002 and 2003 share of total quantity of N₂O usage by sector was obtained from CGA (2002, 2003). Due
44 to the unavailability of data, the share of total quantity of N₂O usage data for years 2004 through 2019 was
45 assumed to equal the 2003 value. The emissions rate for the food processing propellant industry was obtained
46 from SRI Consulting's *Nitrous Oxide, North America* (Heydorn 1997) and confirmed by a N₂O industry expert
47 (Tupman 2003). The emissions rate for all other subcategories was obtained from communication with a N₂O
48 industry expert (Tupman 2003). The emissions rate for the medical/dental subcategory was obtained from the
49 *2006 IPCC Guidelines*.

Uncertainty and Time-Series Consistency – TO BE UPDATED

The overall uncertainty associated with the 2019 N₂O emission estimate from N₂O product usage was calculated using the *2006 IPCC Guidelines* (2006) Approach 2 methodology. Uncertainty associated with the parameters used to estimate N₂O emissions include production data, total market share of each end use, and the emission factors applied to each end use, respectively.

The results of this Approach 2 quantitative uncertainty analysis are summarized in Table 4-111. Nitrous oxide emissions from N₂O product usage were estimated to be between 3.2 and 5.2 MMT CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 24 percent below to 24 percent above the emission estimate of 4.2 MMT CO₂ Eq.

Table 4-111: Approach 2 Quantitative Uncertainty Estimates for N₂O Emissions from N₂O Product Usage (MMT CO₂ Eq. and Percent)

Source	Gas	2019 Emission Estimate (MMT CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			(MMT CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
N ₂ O from Product Uses	N ₂ O	4.2	3.2	5.2	-24%	+24%

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

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

QA/QC and Verification

For more information on the general QA/QC process applied to this source category, consistent with Volume 1, Chapter 6 of the *2006 IPCC Guidelines*, see the QA/QC and Verification Procedures section in the introduction of the IPPU chapter.

Recalculations Discussion

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

Planned Improvements

EPA has recently initiated an evaluation of alternative production statistics for cross-verification and updating time-series activity data, emission factors, assumptions, etc., and a reassessment of N₂O product use subcategories that accurately represent trends. This evaluation includes conducting a literature review of publications and research that may provide additional details on the industry. This work remains ongoing and thus far no additional sources of data have been found to update this category.

Pending additional resources and planned improvement prioritization, EPA may also evaluate production and use cycles, and the potential need to incorporate a time lag between production and ultimate product use and resulting release of N₂O. Additionally, planned improvements include considering imports and exports of N₂O for product uses.

Finally, for future Inventories, EPA will examine data from EPA's GHGRP to improve the emission estimates for the N₂O product use subcategory. Particular attention will be made to ensure aggregated information can be published without disclosing CBI and time-series consistency, as the facility-level reporting data from EPA's GHGRP are not available for all inventory years as required in this Inventory. This is a lower priority improvement, and EPA is still

1 assessing the possibility of incorporating aggregated GHGRP CBI data to estimate emissions; therefore, this
 2 planned improvement is still in development and not incorporated in the current Inventory report.

3 4.27 Industrial Processes and Product Use

4 Sources of Precursor Gases

5 In addition to the main greenhouse gases addressed above, many industrial processes can result in emissions of
 6 various ozone precursors. The reporting requirements of the UNFCCC²⁹⁸ request that information be provided on
 7 precursor greenhouse gases, which include carbon monoxide (CO), nitrogen oxides (NO_x), non-CH₄ volatile organic
 8 compounds (NMVOCs), and sulfur dioxide (SO₂). These gases are not direct greenhouse gases, but indirectly affect
 9 terrestrial radiation absorption by influencing the formation and destruction of tropospheric and stratospheric
 10 ozone, or, in the case of SO₂, by affecting the absorptive characteristics of the atmosphere. Additionally, some of
 11 these gases may react with other chemical compounds in the atmosphere to form compounds that are greenhouse
 12 gases. As some of industrial applications also employ thermal incineration as a control technology, combustion
 13 byproducts, such as CO and NO_x, are also reported with this source category. NMVOCs, commonly referred to as
 14 “hydrocarbons,” are the primary gases emitted from most processes employing organic or petroleum-based
 15 products, and can also result from the product storage and handling.

16 Accidental releases of greenhouse gases associated with product use and handling can constitute major emissions
 17 in this category. In the United States, emissions from product use are primarily the result of solvent evaporation,
 18 whereby the lighter hydrocarbon molecules in the solvents escape into the atmosphere. The major categories of
 19 product uses include: degreasing, graphic arts, surface coating, other industrial uses of solvents (e.g., electronics),
 20 dry cleaning, and non-industrial uses (e.g., uses of paint thinner). Product usage in the United States also results in
 21 the emission of small amounts of hydrofluorocarbons (HFCs) and hydrofluoroethers (HFEs), which are included
 22 under Substitution of Ozone Depleting Substances in this chapter.

23 Total emissions of NO_x, CO, and NMVOCs from non-energy industrial processes and product use from 1990 to 2019
 24 are reported in Table 4-112. Sulfur dioxide emissions are presented in Section 2.3 of the Trends chapter and Annex
 25 6.3.

26 **Table 4-112: NO_x, CO, and NMVOC Emissions from Industrial Processes and Product Use (kt)**

Gas/Source	1990	2005	2015	2016	2017	2018	2019
NO_x	592	572	408	402	397	397	397
Industrial Processes							
Other Industrial Processes ^a	343	437	297	294	291	291	291
Metals Processing	88	60	62	61	60	60	60
Chemical and Allied Product Manufacturing	152	55	41	39	37	37	37
Storage and Transport	3	15	5	5	5	5	5
Miscellaneous ^b	5	2	2	2	3	3	3
Product Uses							
Surface Coating	1	3	1	1	1	1	1
Graphic Arts	+	0	0	0	0	0	0
Degreasing	+	0	0	0	0	0	0
Dry Cleaning	+	0	0	0	0	0	0
Other Industrial Processes ^a	+	0	0	0	0	0	0
Non-Industrial Processes ^c	+	0	0	0	0	0	0
Other	NA	0	0	0	0	0	0

²⁹⁸ See <<http://unfccc.int/resource/docs/2013/cop19/eng/10a03.pdf>>.

CO	4,129	1,557	1,163	1,075	1,006	1,006	1,006
Industrial Processes							
Metals Processing	2,395	752	510	468	425	425	425
Other Industrial Processes ^a	487	484	488	447	406	406	406
Chemical and Allied Product Manufacturing	1,073	189	114	110	107	107	107
Miscellaneous ^b	101	32	42	42	61	61	61
Storage and Transport	69	97	7	7	7	7	7
Product Uses							
Surface Coating	+	2	1	1	1	1	1
Other Industrial Processes ^a	4	0	0	0	0	0	0
Dry Cleaning	+	0	0	0	0	0	0
Degreasing	+	0	0	0	0	0	0
Graphic Arts	+	0	0	0	0	0	0
Non-Industrial Processes ^c	+	0	0	0	0	0	0
Other	NA	0	0	0	0	0	0
NMVOCs	7,638	5,849	3,796	3,776	3,767	3,767	3,767
Industrial Processes							
Storage and Transport	1,352	1,308	619	626	633	633	633
Other Industrial Processes ^a	364	414	314	314	314	314	314
Chemical and Allied Product Manufacturing	575	213	69	69	68	68	68
Metals Processing	20	17	24	24	35	35	35
Miscellaneous ^b	111	45	24	22	20	20	20
Product Uses							
Surface Coating	2,289	1,578	1,124	1,114	1,105	1,105	1,105
Non-Industrial Processes ^c	1,724	1,446	1,030	1,021	1,012	1,012	1,012
Degreasing	675	280	200	198	196	196	196
Dry Cleaning	195	230	164	163	161	161	161
Graphic Arts	249	194	138	137	136	136	136
Other Industrial Processes ^a	85	88	62	62	61	61	61
Other	+	36	26	25	25	25	25

Note: Totals may not sum due to independent rounding.

+ Does not exceed 0.5 kt

NA (Not Available)

^a Includes rubber and plastics manufacturing, and other miscellaneous applications.

^b Miscellaneous includes the following categories: catastrophic/accidental release, other combustion, health services, cooling towers, and fugitive dust. It does not include agricultural fires or slash/prescribed burning, which are accounted for under the Field Burning of Agricultural Residues source.

^c Includes cutback asphalt, pesticide application adhesives, consumer solvents, and other miscellaneous applications.

1 Methodology

- 2 Emission estimates for 1990 through 2019 were obtained from data published on the National Emission Inventory
- 3 (NEI) Air Pollutant Emission Trends web site (EPA 2020) and disaggregated based on EPA (2003). Data were
- 4 collected for emissions of CO, NO_x, volatile organic compounds (VOCs), and SO₂ from metals processing, chemical
- 5 manufacturing, other industrial processes, transport and storage, and miscellaneous sources. Emissions were
- 6 calculated either for individual source categories or for many categories combined, using basic activity data (e.g.,
- 7 the amount of raw material processed or the amount of solvent purchased) as an indicator of emissions. National
- 8 activity data were collected for individual categories from various agencies. Depending on the category, these
- 9 basic activity data may include data on production, fuel deliveries, raw material processed, etc.
- 10 Emissions for product use were calculated by aggregating product use data based on information relating to
- 11 product uses from different applications such as degreasing, graphic arts, etc. Emission factors for each
- 12 consumption category were then applied to the data to estimate emissions. For example, emissions from surface

1 coatings were mostly due to solvent evaporation as the coatings solidify. By applying the appropriate product-
2 specific emission factors to the amount of products used for surface coatings, an estimate of NMVOC emissions
3 was obtained. Emissions of CO and NO_x under product use result primarily from thermal and catalytic incineration
4 of solvent-laden gas streams from painting booths, printing operations, and oven exhaust.

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

10 **Uncertainty and Time-Series Consistency**

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

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

16 **QA/QC and Verification**

17 For more information on the general QA/QC process applied to this source category, consistent with Volume 1,
18 Chapter 6 of the *2006 IPCC Guidelines*, see the QA/QC and Verification Procedures section in the introduction of
19 the IPPU chapter.

20 **Recalculations Discussion**

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

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