ANNEX 2 Methodology and Data for Estimating CO_2 Emissions from Fossil Fuel Combustion

2.1. Methodology for Estimating Emissions of CO_2 from Fossil Fuel Combustion

Carbon dioxide (CO_2) emissions from fossil fuel combustion were estimated using a "bottom-up" methodology characterized by eight steps. These steps are described below.

Step 1: Determine Total Fuel Consumption by Fuel Type and Sector

The bottom-up methodology used by the United States for estimating CO_2 emissions from fossil fuel combustion is conceptually similar to the approach recommended by the Intergovernmental Panel on Climate Change (IPCC) for countries that intend to develop detailed, sector-based emission estimates in line with a Tier 2 method in the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC 2006). Total consumption data and adjustments to consumption are presented in Columns 2 through 13 of Table A-10.

Adjusted consumption data for years 1990, 1995, 2000, 2005, and 2010-2019 are presented in Columns 2 through 8 of Table A-12 through Table A-24 with totals by fuel type in Column 8 and totals by end-use sector in the last rows.[1] Fuel consumption data for the bottom-up approach were obtained directly from the Energy Information Administration (EIA) of the U.S. Department of Energy. These data were first gathered in physical units, and then converted to their energy equivalents (see Annex 6.5 Constants, Units, and Conversions). The EIA data were collected through a variety of consumption surveys at the point of delivery or use and qualified with survey data on fuel production, imports, exports, and stock changes. Individual data elements were supplied by a variety of sources within EIA. Most information was taken from published reports, although some data were drawn from unpublished energy studies and databases maintained by EIA.

Energy use data were aggregated by sector (i.e., residential, commercial, industrial, transportation, electric power, and U.S. Territories), primary fuel type (e.g., coal, natural gas, and petroleum), and secondary fuel type (e.g., motor gasoline, distillate fuel). The 2019 total adjusted energy consumption across all sectors, including U.S. Territories, and energy types was 72,207.8 trillion British thermal units (TBtu), as indicated in the last entry of Column 13 in Table A-10. This total excludes fuel used for non-energy purposes and fuel consumed as international bunkers, both of which were deducted in earlier steps.

Electricity use information was allocated to each sector based on EIA's distribution of electricity retail sales to ultimate customers (i.e., residential, commercial, industrial, and other). Because the "other" fuel use includes sales to both the commercial and transportation sectors, EIA's limited transportation electricity use data were subtracted from "other" electricity use and reported separately, and the remaining "other" electricity use was consequently combined with the commercial electricity data. Further information on these electricity end uses is described in EIA's *Monthly Energy Review* (EIA 2020b). Within the transportation sector, electricity use from electric vehicle charging in commercial and residential locations, not specifically reported by EIA, was calculated and re-allocated from the residential and commercial sectors to the transportation sector, for the years 2010 to present. The methodology for estimating electricity consumption by electric vehicles is outlined in Browning (2018).

There are also three basic differences between the consumption data presented in Table A-10 and Table A-12 through Table A-24 and those recommended in the IPCC (2006) emission inventory methodology.

First, consumption data in the U.S. Inventory are presented using higher heating values (HHV).[2] rather than the lower heating values (LHV).[3] reflected in the IPCC (2006) emission inventory methodology. This convention is followed because data obtained from EIA are based on HHV. Of note, however, is that EIA renewable energy statistics are often

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[1] Adjusted consumption data for other years in the time series are available along with all other data tables for this report on U.S. EPA's homepage at <https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks>.

[2] Also referred to as gross calorific values (GCV).

[3] Also referred to as net calorific values (NCV).

published using LHV. The difference between the two conventions relates to the treatment of the heat energy that is consumed in the process of evaporating the water contained in the fuel. The simplified convention used by the International Energy Agency for converting from HHV to LHV is to multiply the energy content by 0.95 for petroleum and coal and by 0.9 for natural gas.

Second, while EIA's energy use data for the United States includes only the 50 U.S. states and the District of Columbia, the data reported to the United Nations Framework Convention on Climate Change (UNFCCC) are to include energy use within U.S. Territories. Therefore, estimates for U.S. Territories[4] were added to domestic consumption of fossil fuels. Energy use data from U.S. Territories are presented in Column 7 of Table A-12 through Table A-24. It is reported separately from domestic sectoral consumption, because it is collected separately by EIA with no sectoral disaggregation.

Third, there were a number of modifications made in this report that may cause consumption information herein to differ from figures given in the cited literature. These are (1) the reallocation of select amounts of coking coal, petroleum coke, natural gas, residual fuel oil, and other oil (>401 degrees Fahrenheit) for processes accounted for in the Industrial Processes and Product Use chapter, (2) corrections for synthetic natural gas production, (3) subtraction of other fuels used for non-energy purposes, and (4) subtraction of international bunker fuels. These adjustments are described in the following steps.

Step 2: Subtract uses accounted for in the Industrial Processes and Product Use chapter.

Portions of the fuel consumption data for seven fuel categories—coking coal, distillate fuel, industrial other coal, petroleum coke, natural gas, residual fuel oil, and other oil (>401 degrees Fahrenheit)—were reallocated to the Industrial Processes and Product Use (IPPU) chapter, as these portions were consumed as raw materials during non-energy related industrial processes. Emissions from these fuels used as raw materials are presented in the Industrial Processes and Product Use chapter and are removed from the energy and non-energy use estimates within the Energy chapter.

- Coking coal is used as a raw material (specifically as a reducing agent) in the blast furnace process to produce iron and steel, lead, and zinc and therefore is not used as a fuel for this process.
- Similarly, petroleum coke is used in multiple processes as a raw material and is thus not used as a fuel in those applications. The processes in which petroleum coke is used include (1) ferroalloy production, (2) aluminum production (for the production of C anodes and cathodes), (3) titanium dioxide production (in the chloride process), (4) ammonia production, and (5) silicon carbide.
- Natural gas consumption is used for the production of ammonia, and blast furnace and coke oven gas used in iron and steel production.
- Residual fuel oil and other oil (>401 degrees Fahrenheit) are both used in the production of C black.
- Natural gas, distillate fuel, coal, and metallurgical coke are used to produce pig iron through the reduction of iron ore in the production of iron and steel.

Examples of iron and steel production adjustments in allocating emissions in Energy and IPPU sectors:

The consumption of coking coal, natural gas, distillate fuel, and coal used in iron and steel production are adjusted within the Energy chapter to avoid double counting of emissions from consumption of these fuels during activities in IPPU related sectors. These fuels are adjusted based on activity data utilized in calculating emissions estimates within the Iron and Steel Production section. Iron and steel production is an industrial process in which coal coke is used as a raw material rather than as a fuel;[5] as such, the total use of industrial coking coal, as reported by EIA, is adjusted downward to account for this consumption within the iron and steel category. In this case, if the reported amount of coking coal used in these processes is greater than the amount of coking coal consumption reported by the

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[4] Fuel consumption by U.S. Territories (i.e., American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands) is included in this report.

[5] In addition to iron and steel, lead and zinc production are also industrial processes in which coal coke is used as a raw material. Iron and steel, lead and zinc production accounts for the major portion of consumption of coal coke in the United States.

EIA, the excess amount of coking coal used in these processes that is greater than the amount reported from consumption is subtracted from the industrial other coal fuel type.

In 2019, 17,924 thousand tons of coking coal were consumed,[6] resulting in an Energy sector adjustment of 382 TBtu. Natural gas, fuel oil, and coal are other fossil fuels also used in the production of iron and steel; therefore, the consumption of these fuels in industrial processes is subtracted from the industrial fossil fuel combustion sector to account for the amount of fuel used in the iron and steel calculation. In 2019, the iron and steel industry consumed 2,465 tons of coal (bituminous), 49,238 million ft^3 of natural gas, and 2,321 thousand gallons of distillate fuel as fuel. This resulted in Energy chapter adjustments of roughly 59 TBtu for coal, 51 TBtu for natural gas, and less than 1 TBtu for distillate fuel. In addition, an additional 132 TBtu is adjusted to account for coking coal consumed for industrial processes other than iron and steel, lead, and zinc production in 2019.

Step 3: Adjust for Conversion of Fossil Fuels and Exports

First, ethanol has been added to the motor gasoline stream for many years, but prior to 1993 this addition was not captured in EIA motor gasoline statistics. Starting in 1993, ethanol was included in gasoline statistics. Carbon dioxide emissions from ethanol added to motor gasoline are not included specifically in summing energy sector totals. Net carbon fluxes from changes in biogenic carbon reservoirs are accounted for in the estimates for LULUCF, therefore, fuel consumption estimates are adjusted to remove ethanol. Thus, motor gasoline consumption statistics given in this report exclude ethanol and may be slightly lower than in EIA sources for finished gasoline that includes ethanol.

Second, EIA distillate fuel oil consumption statistics include “biodiesel” and “other renewable diesel fuel” consumption starting in 2009. Carbon dioxide emissions from biodiesel and other renewable diesel added to diesel fuel are not included specifically in summing energy sector totals. Net carbon fluxes from changes in biogenic carbon reservoirs are accounted for in the estimates for LULUCF, therefore, fuel consumption estimates are adjusted to remove biodiesel and other renewable diesel fuel. Thus, distillate fuel oil consumption statistics for the transportation sector in this report may be slightly lower than in EIA sources.

Third, a portion of industrial “other” coal that is accounted for in EIA coal combustion statistics is actually used to make “synthetic natural gas” via coal gasification at the Dakota Gasification Plant, a synthetic natural gas plant. The plant produces synthetic natural gas and byproduct CO_2. Since October 2000, a portion of the CO_2 produced by the coal gasification plant has been exported to Canada by pipeline. The energy in this synthetic natural gas enters the natural gas distribution stream, however it is accounted for in EIA coal combustion statistics.[7] The exported CO_2 is not emitted to the atmosphere in the United States, and therefore the energy associated with the amount of CO_2 exported is subtracted from industrial other coal.

Step 4: Adjust Sectoral Allocation of Distillate Fuel Oil and Motor Gasoline

EPA conducted a separate bottom-up analysis of transportation fuel consumption based on data from the Federal Highway Administration (FHWA). The FHWA data indicated that the amount of distillate and motor gasoline consumption allocated to the transportation sector in the EIA statistics should be adjusted. Therefore, for the estimates presented in the U.S. Inventory, the transportation sector’s distillate fuel and motor gasoline consumption were adjusted to match the value obtained from the bottom-up analysis. As the total distillate and motor gasoline consumption estimate from EIA are considered to be accurate at the national level, the distillate and motor gasoline consumption totals for the residential, commercial, and industrial sectors were adjusted proportionately.

Step 5: Subtract Consumption for Non-Energy Use

U.S. aggregate energy statistics include consumption of fossil fuels for non-energy purposes. Depending on the end-use, non-energy uses of fossil fuels can result in long term storage of some or all of the C contained in the fuel. For example, asphalt made from petroleum can sequester up to 100 percent of the C contained in the petroleum feedstock for extended periods of time. Other non-energy fossil fuel products, such as lubricants or plastics also store C, but can lose or emit some of this C when they are used and/or burned as waste. As the emission pathways of C used for non-energy purposes are vastly different than fuel combustion, these emissions are estimated separately in the Carbon

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[6] Coking coal includes non-imported coke consumption from the iron and steel, lead, and zinc industries.

[7] To avoid double-counting, EIA’s MER statistics account for supplemental gaseous fuels (including synthetic natural gas) in their primary energy category (i.e., coal, petroleum, or biomass) (EIA 2020b).

Emitted in Products from Non-Energy Uses of Fossil Fuels section in this chapter. Therefore, the amount of fuels used for non-energy purposes, shown in Table A-25, was subtracted from total fuel consumption.

Step 6: Subtract Consumption of International Bunker Fuels

Emissions from international transport activities, or international bunker fuel consumption, are not included in national totals and instead reported separately, as required by the IPCC (2006) and UNFCCC (2014) inventory reporting guidelines. EIA energy statistics, however, include these bunker fuels jet fuel for aircraft, and distillate fuel oil and residual fuel oil for marine shipping as part of fuel consumption by the transportation end-use sector. Therefore, the amount of consumption for international bunker fuels was estimated and subtracted from total fuel consumption (see Table A-26). Emissions from international bunker fuels have been estimated separately and not included in national totals.[8]

Step 7: Determine the C Content of All Fuels

The C content of combusted fossil fuels was estimated by multiplying adjusted energy consumption (Columns 2 through 8 of Table A-12 through Table A-24) by fuel-specific C content coefficients (see Table A-27 and Table A-28) that reflect the amount of C per unit of energy in each fuel. The C content coefficients used in the Inventory were derived in part by EIA and EPA from detailed fuel information and are similar to the C content coefficients contained in the IPCC's default methodology (IPCC 2006), with modifications reflecting fuel qualities specific to the United States.

For geothermal electricity production, C content was estimated by multiplying net generation for each geotype (see Table A-31) by technology-specific C content coefficients (see Table A-27). For industrial energy and non-energy hydrocarbon gas liquids (HGL)[9] consumption, annually variable C contents were estimated by multiplying annual energy and non-energy consumption for each HGL component (e.g., ethane, ethylene, propane, propylene) by its respective C content coefficient (see Table A-28).

Step 8: Estimate CO_2 Emissions

Actual CO_2 emissions in the United States were summarized by major fuel (i.e., coal, petroleum, natural gas, geothermal) and consuming sector (i.e., residential, commercial, industrial, transportation, electric power, and U.S. Territories). Emission estimates are expressed in million metric tons of carbon dioxide equivalents (MMT CO_2 Eq.). To convert from C content to CO_2 emissions, the fraction of C that is oxidized was applied. This fraction was 100 percent based on guidance in IPCC (2006).

To determine total emissions by final end-use sector, emissions from electric power were distributed to each end-use sector according to its share of aggregate electricity use (see Table A-29). This pro-rated approach to allocating emissions from electric power may overestimate or underestimate emissions for particular sectors due to differences in the average C content of fuel mixes burned to generate electricity.

To provide a more detailed accounting of emissions from transportation, fuel consumption data by vehicle type and transportation mode were used to allocate emissions by fuel type calculated for the transportation end-use sector. Additional information on the allocation is available in Annex 3.1.

Box A-1: Uses of Greenhouse Gas Reporting Program Data in Reporting Emissions from Industrial Sector Fossil Fuel Combustion

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

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[8] Refer to the International Bunker Fuels section of the Energy chapter and Annex 3.3 for a description of the methodology for distinguishing between international and domestic fuel consumption.

[9] EIA defines HGL as "a group of hydrocarbons including ethane, propane, normal butane, isobutane, and natural gasoline, and their associated olefins, including ethylene, propylene, butylene, and isobutylene" (EIA 2020b).

For EPA's GHGRP 2010 through 2019 reporting years, facility-level fossil fuel combustion emissions reported through EPA's GHGRP were categorized and distributed to specific industry types by utilizing facility-reported NAICS codes (as published by the U.S. Census Bureau). As noted previously in this report, the definitions and provisions for reporting fuel types in EPA's GHGRP include some differences from the Inventory's use of EIA national fuel statistics to meet the UNFCCC reporting guidelines. The IPCC has provided guidance on aligning facility-level reported fuels and fuel types published in national energy statistics, which guided this exercise.[10]

As with previous Inventory reports, this year's effort represents an attempt to align, reconcile, and coordinate the facility-level reporting of fossil fuel combustion emissions under EPA's GHGRP with the national-level approach presented in this report. Consistent with recommendations for reporting the Inventory to the UNFCCC, progress was made on certain fuel types for specific industries and has been included in the Common Reporting Format (CRF) tables that are submitted to the UNFCCC along with this report.[11] The efforts in reconciling fuels focus on standard, common fuel types (e.g., natural gas, distillate fuel oil) where the fuels in EIA's national statistics aligned well with facility-level GHGRP data. For these reasons, the current information presented in the CRF tables should be viewed as an initial attempt at this exercise. Additional efforts will be made for future Inventory reports to improve the mapping of fuel types, and examine ways to reconcile and coordinate any differences between facility-level data and national statistics.

This year's analysis includes the full time series presented in the CRF tables. Analyses were conducted linking GHGRP facility-level reporting with the information published by EIA in its MECS data in order to disaggregate the full 1990 through 2019 time series in the CRF tables. It is believed that the current analysis has led to improvements in the presentation of data in the Inventory, but further work will be conducted, and future improvements will be realized in subsequent Inventory reports. This includes incorporating the latest MECS data as it becomes available.

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

[11] See <http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html>.

Table A-10: 2019 Energy Consumption Data by Fuel Type (TBtu) and Adjusted Energy Consumption Data

1	2	3	4	5	6	7	8	9	10	11	12	13
	Total Consumption (TBtu)[a]							Adjustments (TBtu)[b]				Total Adjusted Consumption (TBtu)
									Unadjusted NEU Consumption			
Fuel Type	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**	**Bunker Fuel**	**Ind.**	**Trans.**	**Terr.**	
Total Coal	**NO**	**16.7**	**659.0**	**NO**	**10,181.2**	**27.1**	**10,884.0**		**141.5**			**10,742.5**
Residential Coal	NO						NO					NO
Commercial Coal		16.7					16.7					16.7
Industrial Other Coal			526.9				526.9		9.5			517.4
Transportation Coal				NO			NO					NO
Electric Power Coal					10,181.2		10,181.2					10,181.2
U.S. Territory Coal (bit)						27.1	27.1					27.1
Natural Gas	**5,204.9**	**3,645.1**	**10,245.4**	**1,035.2**	**11,645.4**	**48.2**	**31,824.2**		**730.8**			**31,093.5**
Total Petroleum	**904.3**	**787.4**	**8,639.7**	**26,309.2**	**188.6**	**279.8**	**37,108.9**	**1,618.6**	**5,024.8**	**132.1**	**10.7**	**30,322.7**
Asphalt & Road Oil			843.9				843.9		843.9			
Aviation Gasoline				23.4			23.4					23.4
Distillate Fuel Oil	398.7	277.3	1,021.5	6,624.8	53.9	80.3	8,456.5	136.3	5.8			8,314.4
Jet Fuel				3,608.0	NA	30.8	3,638.8	1,146.1				2,492.7
Kerosene	10.3	1.7	2.0			0.5	14.5					14.5
LPG (Propane)	495.2	172.0		7.5			674.8					674.8
HGL			2,887.4			6.4	2,893.8		2,758.8			135.0
Lubricants			117.6	132.1		1.0	250.7		117.6	132.1	1.0	
Motor Gasoline		333.6	245.3	15,381.1		105.0	16,064.9					16,064.9
Residual Fuel		2.7		532.2	58.8	46.2	639.9	336.2				303.7
Other Petroleum												
AvGas Blend Components			(1.2)				(1.2)					(1.2)
Crude Oil												
MoGas Blend Components												
Misc. Products			180.2			9.6	189.8		180.2		9.6	
Naphtha (<401 deg. F)			396.7				396.7		396.7			
Other Oil (>401 deg. F)			234.1				234.1		234.1			
Pentanes Plus			334.6				334.6		166.6			167.9
Petroleum Coke		0.2	602.3		75.9		678.4		56.4			622.0
Still Gas			1,533.5				1,533.5		158.7			1,374.7
Special Naphtha			95.6				95.6		95.6			
Unfinished Oils			135.9				135.9					135.9
Waxes			10.4				10.4		10.4			
Geothermal					**52.8**		**52.8**					**52.8**
Total (All Fuels)	**6,109.1**	**4,449.3**	**19,544.1**	**27,344.4**	**22,067.9**	**355.1**	**79,869.9**	**1,618.6**	**5,897.1**	**132.1**	**10.7**	**72,211.5**

Note: Parentheses indicate negative values.

NO (Not Occurring)

NA (Not Available)

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-25), and international bunker fuel consumption (see Table A-26).

[b] Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.

Table A-11: 2019 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (MMT CO_2 Eq.) from Energy Use						
Fuel Type	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**
Total Coal	**NO**	**16.7**	**517.4**	**NO**	**10,181.2**	**27.1**	**10,742.5**	**NO**	**1.6**	**49.5**	**NO**	**973.5**	**2.5**	**1,027.1**
Residential Coal	NO						NO	NO						NO
Commercial Coal		16.7					16.7		1.6					1.6
Industrial Other Coal			517.4				517.4			49.5				49.5
Transportation Coal				NO			NO				NO			NO
Electric Power Coal					10,181.2		10,181.2					973.5		973.5
U.S. Territory Coal (bit)						27.1	27.1						2.5	2.5
Natural Gas	**5,204.9**	**3,645.1**	**9,514.7**	**1,035.2**	**11,645.4**	**48.2**	**31,093.5**	**275.3**	**192.8**	**503.3**	**54.8**	**616.0**	**2.5**	**1,644.6**
Total Petroleum	**904.3**	**787.4**	**3,614.9**	**24,558.5**	**188.6**	**269.1**	**30,322.7**	**61.5**	**55.3**	**269.7**	**1,762.5**	**16.2**	**19.5**	**2,184.6**
Asphalt & Road Oil														
Aviation Gasoline				23.4			23.4				1.6			1.6
Distillate Fuel Oil	398.7	277.3	1,015.6	6,488.6	53.9	80.3	8,314.4	29.6	20.6	75.3	481.1	4.0	6.0	616.4
Jet Fuel				2,461.9	NA	30.8	2,492.7				177.8	NA	2.2	180.0
Kerosene	10.3	1.7	2.0			0.5	14.5	0.8	0.1	0.1			+	1.1
LPG (Propane)	495.2	172.0		7.5			674.8	31.1	10.8		0.5			42.4
HGL			128.6			6.4	135.0			8.2			0.4	8.7
Lubricants														
Motor Gasoline		333.6	245.3	15,381.1		105.0	16,064.9		23.6	17.3	1,086.8		7.4	1,135.1
Residual Fuel		2.7		196.0	58.8	46.2	303.7		0.2		14.7	4.4	3.5	22.8
Other Petroleum														
AvGas Blend Components			(1.2)				(1.2)			(0.1)				(0.1)
Crude Oil														
MoGas Blend Components														
Misc. Products														
Naphtha (<401 deg. F)														
Other Oil (>401 deg. F)														
Pentanes Plus			167.9				167.9			11.2				11.2
Petroleum Coke		0.2	545.9		75.9		622.0		+	55.7		7.8		63.5
Still Gas			1,374.7				1,374.7			91.7				91.7
Special Naphtha														
Unfinished Oils			135.9				135.9			10.1				10.1
Waxes														
Geothermal					**52.8**		**52.8**					**0.4**		**0.4**
Total (All Fuels)	**6,109.1**	**4,449.3**	**13,647.0**	**25,593.7**	**22,067.9**	**344.4**	**72,211.5**	**336.8**	**249.7**	**822.5**	**1,817.2**	**1,606.0**	**24.6**	**4,856.7**

Note: Parentheses indicate negative values.

+ Does not exceed 0.05 TBtu or 0.05 MMT CO_2 Eq.

NO (Not Occurring)

NA (Not Available)

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-25), and international bunker fuel consumption (see Table A-26).

[b] Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.

Table A-12: 2018 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] ($MMT CO_2$ Eq.) from Energy Use						
Fuel Type	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**
Total Coal	**NO**	**18.7**	**569.0**	**NO**	**12,053.0**	**27.1**	**12,667.9**	**NO**	**1.8**	**54.4**	**NO**	**1,152.9**	**2.5**	**1,211.6**
Residential Coal	NO						NO	NO						NO
Commercial Coal		18.7					18.7		1.8					1.8
Industrial Other Coal			569.0				569.0			54.4				54.4
Transportation Coal				NO			NO				NO			NO
Electric Power Coal					12,053.0		12,053.0					1,152.9		1,152.9
U.S. Territory Coal (bit)						27.1	27.1						2.5	2.5
Natural Gas	**5,174.4**	**3,638.3**	**9,334.9**	**962.2**	**10,912.1**	**48.1**	**30,070.0**	**273.8**	**192.5**	**494.0**	**50.9**	**577.4**	**2.5**	**1,591.2**
Total Petroleum	**943.6**	**733.3**	**3,544.4**	**24,606.6**	**260.4**	**269.1**	**30,357.4**	**64.2**	**51.4**	**265.2**	**1,765.6**	**22.2**	**19.5**	**2,188.2**
Asphalt & Road Oil														
Aviation Gasoline				22.4			22.4				1.5			1.5
Distillate Fuel Oil	428.8	273.0	1,052.9	6,476.5	80.6	80.3	8,392.1	31.8	20.2	78.1	480.2	6.0	6.0	622.2
Jet Fuel				2,386.0	NA	30.8	2,416.8				172.3	NA	2.2	174.5
Kerosene	8.2	1.3	1.6			0.5	11.7	0.6	0.1	0.1			+	0.9
LPG (Propane)	506.5	176.0		7.7			690.2	31.8	11.1		0.5			43.4
HGL			127.3			6.4	133.7			8.1			0.4	8.6
Lubricants														
Motor Gasoline		279.5	205.6	15,527.5		105.0	16,117.7		19.8	14.5	1,097.1		7.4	1,138.8
Residual Fuel		3.1		186.5	78.3	46.2	314.0		0.2		14.0	5.9	3.5	23.6
Other Petroleum														
AvGas Blend Components			(1.6)				(1.6)			(0.1)				(0.1)
Crude Oil														
MoGas Blend Components														
Misc. Products														
Naphtha (<401 deg. F)														
Other Oil (>401 deg. F)														
Pentanes Plus			112.7				112.7			7.5				7.5
Petroleum Coke		0.4	569.8		101.5		671.6		+	58.2		10.4		68.6
Still Gas			1,445.3				1,445.3			96.4				96.4
Special Naphtha														
Unfinished Oils			30.9				30.9			2.3				2.3
Waxes														
Geothermal					**54.5**		**54.5**					**0.4**		**0.4**
Total (All Fuels)	**6,118.0**	**4,390.3**	**13,448.3**	**25,568.8**	**23,279.9**	**344.4**	**73,149.7**	**338.1**	**245.7**	**813.6**	**1,816.6**	**1,752.9**	**24.6**	**4,991.4**

Note: Parentheses indicate negative values.

+ Does not exceed 0.05 TBtu or 0.05 $MMT CO_2$ Eq.

NO (Not Occurring)

NA (Not Available)

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-25), and international bunker fuel consumption (see Table A-26).

[b] Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.

Table A-13: 2017 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							**Emissions[b] (MMT CO_2 Eq.) from Energy Use**						
Fuel Type	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**
Total Coal	**NO**	**20.7**	**614.1**	**NO**	**12,622.2**	**27.1**	**13,284.1**	**NO**	**2.0**	**58.7**	**NO**	**1,207.1**	**2.5**	**1,270.2**
Residential Coal	NO						NO	NO						NO
Commercial Coal		20.7					20.7		2.0					2.0
Industrial Other Coal			614.1				614.1			58.7				58.7
Transportation Coal				NO			NO				NO			NO
Electric Power Coal					12,622.2		12,622.2					1,207.1		1,207.1
U.S. Territory Coal (bit)						27.1	27.1						2.5	2.5
Natural Gas	**4,563.5**	**3,272.9**	**8,872.4**	**798.6**	**9,555.2**	**48.1**	**27,110.6**	**241.5**	**173.2**	**469.5**	**42.3**	**505.6**	**2.5**	**1,434.6**
Total Petroleum	**766.1**	**808.9**	**3,512.7**	**24,250.4**	**217.7**	**269.1**	**29,824.9**	**51.9**	**56.8**	**261.9**	**1,740.2**	**18.9**	**19.5**	**2,149.2**
Asphalt & Road Oil														
Aviation Gasoline				20.9			20.9				1.4			1.4
Distillate Fuel Oil	327.0	244.0	905.0	6,322.2	54.7	80.3	7,933.2	24.2	18.1	67.0	468.3	4.1	6.0	587.6
Jet Fuel				2,378.1	NA	30.8	2,408.9				171.8	NA	2.2	174.0
Kerosene	8.4	1.2	1.1			0.5	11.2	0.6	0.1	0.1			+	0.8
LPG (Propane)	430.7	155.7		7.1			593.5	27.1	9.8		0.4			37.3
HGL			175.6			6.4	182.0			11.2			0.4	11.6
Lubricants														
Motor Gasoline		403.7	295.7	15,302.8		105.0	16,107.2		28.5	20.9	1,081.8		7.4	1,138.7
Residual Fuel		3.8		219.3	65.8	46.2	335.0		0.3		16.5	4.9	3.5	25.2
Other Petroleum														
AvGas Blend Components			(0.2)				(0.2)			(+)				(+)
Crude Oil														
MoGas Blend Components														
Misc. Products														
Naphtha (<401 deg. F)														
Other Oil (>401 deg. F)														
Pentanes Plus			87.0				87.0			5.8				5.8
Petroleum Coke		0.5	553.0		97.2		650.8		0.1	56.5		9.9		66.4
Still Gas			1,419.0				1,419.0			94.7				94.7
Special Naphtha														
Unfinished Oils			76.4				76.4			5.7				5.7
Waxes														
Geothermal					**54.3**		**54.3**					**0.4**		**0.4**
Total (All Fuels)	**5,329.6**	**4,102.4**	**12,999.2**	**25,049.0**	**22,449.5**	**344.4**	**70,274.0**	**293.4**	**232.0**	**790.1**	**1,782.4**	**1,732.0**	**24.6**	**4,854.5**

Note: Parentheses indicate negative values.

+ Does not exceed 0.05 TBtu or 0.05 MMT CO_2 Eq.

NO (Not Occurring)

NA (Not Available)

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-25), and international bunker fuel consumption (see Table A-26).

[b] Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.

Table A-14: 2016 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (MMT CO_2 Eq.) from Energy Use						
Fuel Type	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**
Total Coal	**NO**	**23.7**	**661.6**	**NO**	**12,996.4**	**34.9**	**13,716.6**	**NO**	**2.3**	**63.2**	**NO**	**1,242.0**	**3.2**	**1,310.7**
Residential Coal	NO						NO	NO						NO
Commercial Coal		23.7					23.7		2.3					2.3
Industrial Other Coal			661.6				661.6			63.2				63.2
Transportation Coal				NO			NO				NO			NO
Electric Power Coal					12,996.4		12,996.4					1,242.0		1,242.0
U.S. Territory Coal (bit)						34.9	34.9						3.2	3.2
Natural Gas	**4,505.8**	**3,223.5**	**8,769.1**	**757.2**	**10,301.3**	**63.6**	**27,620.6**	**238.4**	**170.5**	**463.9**	**40.1**	**545.0**	**3.4**	**1,461.3**
Total Petroleum	**799.2**	**834.5**	**3,551.6**	**23,980.8**	**243.9**	**267.7**	**29,677.7**	**54.4**	**58.7**	**265.4**	**1,719.8**	**21.5**	**19.4**	**2,139.2**
Asphalt & Road Oil														
Aviation Gasoline				20.5			20.5				1.4			1.4
Distillate Fuel Oil	355.7	266.8	939.9	6,129.2	54.9	80.2	7,826.6	26.4	19.8	69.6	454.2	4.1	5.9	580.0
Jet Fuel				2,298.8	NA	29.6	2,328.3				166.0	NA	2.1	168.2
Kerosene	13.7	2.1	2.3			0.4	18.4	1.0	0.2	0.2			+	1.3
LPG (Propane)	429.9	150.0		7.1			587.0	27.0	9.4		0.4			36.9
HGL			227.4			6.3	233.7			14.5			0.4	14.9
Lubricants														
Motor Gasoline		410.8	287.2	15,352.9		105.0	16,155.9		29.0	20.3	1,084.8		7.4	1,141.5
Residual Fuel		4.4		172.4	70.7	46.2	293.7		0.3		12.9	5.3	3.5	22.1
Other Petroleum														
AvGas Blend Components			(0.3)				(0.3)			(+)				(+)
Crude Oil														
MoGas Blend Components														
Misc. Products														
Naphtha (<401 deg. F)														
Other Oil (>401 deg. F)														
Pentanes Plus			56.5				56.5			3.8				3.8
Petroleum Coke		0.3	591.4		118.3		710.1		+	60.4		12.1		72.5
Still Gas			1,438.6				1,438.6			96.0				96.0
Special Naphtha														
Unfinished Oils			8.6				8.6			0.6				0.6
Waxes														
Geothermal					**54.0**		**54.0**					**0.4**		**0.4**
Total (All Fuels)	**5,305.0**	**4,081.7**	**12,982.4**	**24,738.0**	**23,595.6**	**366.2**	**71,068.9**	**292.8**	**231.6**	**792.5**	**1,759.9**	**1,808.9**	**26.0**	**4,911.5**

Note: Parentheses indicate negative values.

+ Does not exceed 0.05 TBtu or 0.05 MMT CO_2 Eq.

NO (Not Occurring)

NA (Not Available)

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-25), and international bunker fuel consumption (see Table A-26).

[b] Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.

Table A-15: 2015 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (MMT CO_2 Eq.) from Energy Use						
Fuel Type	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**
Total Coal	**NO**	**31.1**	**733.9**	**NO**	**14,138.3**	**44.9**	**14,948.1**	**NO**	**3.0**	**70.0**	**NO**	**1,351.4**	**4.1**	**1,428.5**
Residential Coal	NO						NO	NO						NO
Commercial Coal		31.1					31.1		3.0					3.0
Industrial Other Coal			733.9				733.9			70.0				70.0
Transportation Coal				NO			NO				NO			NO
Electric Power Coal					14,138.3		14,138.3					1,351.4		1,351.4
U.S. Territory Coal (bit)						44.9	44.9						4.1	4.1
Natural Gas	**4,776.9**	**3,315.6**	**8,678.5**	**744.8**	**9,926.5**	**57.4**	**27,499.8**	**252.7**	**175.4**	**459.1**	**39.4**	**525.2**	**3.0**	**1,454.9**
Total Petroleum	**938.9**	**937.9**	**3,580.7**	**23,435.1**	**276.0**	**303.8**	**29,472.5**	**64.6**	**66.2**	**268.2**	**1,679.8**	**23.7**	**22.1**	**2,124.5**
Asphalt & Road Oil														
Aviation Gasoline				21.1			21.1				1.5			1.5
Distillate Fuel Oil	483.1	315.5	1,018.0	6,170.4	70.4	78.8	8,136.2	35.8	23.4	75.5	457.5	5.2	5.8	603.2
Jet Fuel				2,181.9	NA	36.0	2,217.9				157.6	NA	2.6	160.2
Kerosene	10.1	1.4	1.7			0.1	13.4	0.7	0.1	0.1			+	1.0
LPG (Propane)	445.7	148.0		6.6			600.3	28.0	9.3		0.4			37.7
HGL			243.3			6.2	249.5			15.5			0.4	15.9
Lubricants														
Motor Gasoline		468.6	321.4	14,998.5		113.0	15,901.4		33.1	22.7	1,058.6		8.0	1,122.4
Residual Fuel		4.0		56.6	93.9	69.6	224.0		0.3		4.2	7.0	5.2	16.8
Other Petroleum														
AvGas Blend Components			(0.3)				(0.3)			(+)				(+)
Crude Oil														
MoGas Blend Components														
Misc. Products														
Naphtha (<401 deg. F)														
Other Oil (>401 deg. F)														
Pentanes Plus			80.9				80.9			5.4				5.4
Petroleum Coke		0.5	600.8		111.7		713.0		0.1	61.3		11.4		72.8
Still Gas			1,332.9				1,332.9			88.9				88.9
Special Naphtha														
Unfinished Oils			(17.8)				(17.8)			(1.3)				(1.3)
Waxes														
Geothermal					**54.3**		**54.3**					**0.4**		**0.4**
Total (All Fuels)	**5,715.9**	**4,284.6**	**12,993.1**	**24,180.0**	**24,395.0**	**406.1**	**71,974.7**	**317.3**	**244.6**	**797.3**	**1,719.2**	**1,900.6**	**29.2**	**5,008.3**

Note: Parentheses indicate negative values.

+ Does not exceed 0.05 TBtu or 0.05 MMT CO_2 Eq.

NO (Not Occurring)

NA (Not Available)

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-25), and international bunker fuel consumption (see Table A-26).

[b] Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.

Table A-16: 2014 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (MMT CO_2 Eq.) from Energy Use						
Fuel Type	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**
Total Coal	**NO**	**40.2**	**833.0**	**NO**	**16,427.4**	**43.8**	**17,344.4**	**NO**	**3.8**	**79.2**	**NO**	**1,568.6**	**4.0**	**1,655.7**
Residential Coal	NO						NO	NO						NO
Commercial Coal		40.2					40.2		3.8					3.8
Industrial Other Coal			833.0				833.0			79.2				79.2
Transportation Coal				NO			NO				NO			NO
Electric Power Coal					16,427.4		16,427.4					1,568.6		1,568.6
U.S. Territory Coal (bit)						43.8	43.8						4.0	4.0
Natural Gas	**5,242.5**	**3,571.9**	**8,817.9**	**759.7**	**8,361.7**	**60.6**	**26,814.3**	**277.7**	**189.2**	**467.0**	**40.2**	**442.9**	**3.2**	**1,420.2**
Total Petroleum	**1,003.2**	**558.1**	**3,567.9**	**23,266.4**	**295.5**	**295.7**	**28,986.9**	**68.9**	**39.4**	**268.2**	**1,668.0**	**25.3**	**21.4**	**2,091.2**
Asphalt & Road Oil														
Aviation Gasoline				21.7			21.7				1.5			1.5
Distillate Fuel Oil	500.0	334.4	1,273.2	6,002.9	82.2	65.6	8,258.3	37.1	24.8	94.4	445.3	6.1	4.9	612.6
Jet Fuel				2,054.3	NA	35.0	2,089.3				148.4	NA	2.5	150.9
Kerosene	13.7	2.0	2.8			0.1	18.7	1.0	0.1	0.2			+	1.4
LPG (Propane)	489.5	160.5		7.2			657.1	30.8	10.1		0.4			41.3
HGL			177.9			6.4	184.3			11.4			0.4	11.8
Lubricants														
Motor Gasoline		52.7	205.6	15,103.0		126.7	15,488.0		3.7	14.5	1,066.6		8.9	1,093.8
Residual Fuel		7.9		77.4	95.1	61.9	242.4		0.6		5.8	7.1	4.7	18.2
Other Petroleum														
AvGas Blend Components			(0.1)				(0.1)			(+)				(+)
Crude Oil														
MoGas Blend Components														
Misc. Products														
Naphtha (<401 deg. F)														
Other Oil (>401 deg. F)														
Pentanes Plus			44.5				44.5			3.0				3.0
Petroleum Coke		0.5	592.1		118.2		710.8		0.1	60.5		12.1		72.6
Still Gas			1,352.4				1,352.4			90.2				90.2
Special Naphtha														
Unfinished Oils			(80.6)				(80.6)			(6.0)				(6.0)
Waxes														
Geothermal					**54.2**		**54.2**					**0.4**		**0.4**
Total (All Fuels)	**6,245.7**	**4,170.2**	**13,218.9**	**24,026.1**	**25,138.7**	**400.1**	**73,199.7**	**346.5**	**232.4**	**814.5**	**1,708.2**	**2,037.2**	**28.7**	**5,167.5**

Note: Parentheses indicate negative values.

+ Does not exceed 0.05 TBtu or 0.05 MMT CO_2 Eq.

NO (Not Occurring)

NA (Not Available)

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-25), and international bunker fuel consumption (see Table A-26).

[b] Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.

Table A-17: 2013 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (MMT CO_2 Eq.) from Energy Use						
Fuel Type	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**
Total Coal	**NO**	**41.4**	**836.8**	**NO**	**16,450.6**	**30.8**	**17,359.6**	**NO**	**3.9**	**79.5**	**NO**	**1,571.3**	**2.8**	**1,657.6**
Residential Coal	NO						NO	NO						NO
Commercial Coal		41.4					41.4		3.9					3.9
Industrial Other Coal			836.8				836.8			79.5				79.5
Transportation Coal				NO			NO				NO			NO
Electric Power Coal					16,450.6		16,450.6					1,571.3		1,571.3
U.S. Territory Coal (bit)						30.8	30.8						2.8	2.8
Natural Gas	**5,022.9**	**3,379.8**	**8,512.5**	**887.3**	**8,376.3**	**58.2**	**26,237.0**	**266.4**	**179.2**	**451.4**	**47.0**	**444.2**	**3.1**	**1,391.3**
Total Petroleum	**916.8**	**580.6**	**4,075.6**	**22,613.7**	**255.2**	**298.8**	**28,740.7**	**62.8**	**41.1**	**303.4**	**1,622.8**	**22.4**	**21.7**	**2,074.1**
Asphalt & Road Oil														
Aviation Gasoline				22.4			22.4				1.5			1.5
Distillate Fuel Oil	445.1	311.2	1,138.8	5,804.1	55.4	71.9	7,826.5	33.0	23.1	84.5	430.5	4.1	5.3	580.5
Jet Fuel				2,036.9	NA	30.0	2,067.0				147.1	NA	2.2	149.3
Kerosene	8.3	1.0	1.5			0.1	10.9	0.6	0.1	0.1			+	0.8
LPG (Propane)	463.5	151.6		6.9			622.0	29.1	9.5		0.4			39.1
HGL			294.0			6.3	300.3			18.7			0.4	19.2
Lubricants														
Motor Gasoline		92.1	606.2	14,542.0		117.5	15,357.8		6.5	42.9	1,028.0		8.3	1,085.7
Residual Fuel		24.4		201.4	77.2	72.9	375.9		1.8		15.1	5.8	5.5	28.2
Other Petroleum														
AvGas Blend Components			(0.4)				(0.4)			(+)				(+)
Crude Oil														
MoGas Blend Components														
Misc. Products														
Naphtha (<401 deg. F)														
Other Oil (>401 deg. F)														
Pentanes Plus			47.5				47.5			3.2				3.2
Petroleum Coke		0.4	600.9		122.5		723.7		+	61.4		12.5		73.9
Still Gas			1,370.6				1,370.6			91.4				91.4
Special Naphtha														
Unfinished Oils			16.7				16.7			1.2				1.2
Waxes														
Geothermal					**53.8**		**53.8**					**0.4**		**0.4**
Total (All Fuels)	**5,939.8**	**4,001.8**	**13,424.9**	**23,501.0**	**25,135.8**	**387.8**	**72,391.2**	**329.1**	**224.2**	**834.3**	**1,669.8**	**2,038.3**	**27.6**	**5,123.3**

Note: Parentheses indicate negative values.

+ Does not exceed 0.05 TBtu or 0.05 MMT CO_2 Eq.

NO (Not Occurring)

NA (Not Available)

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-25), and international bunker fuel consumption (see Table A-26).

[b] Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.

Table A-18: 2012 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (MMT CO_2 Eq.) from Energy Use						
Fuel Type	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**
Total Coal	**NO**	**43.6**	**822.6**	**NO**	**15,821.2**	**36.9**	**16,724.3**	**NO**	**4.1**	**78.2**	**NO**	**1,511.7**	**3.4**	**1,597.5**
Residential Coal	NO						NO	NO						NO
Commercial Coal		43.6					43.6		4.1					4.1
Industrial Other Coal			822.6				822.6			78.2				78.2
Transportation Coal				NO			NO				NO			NO
Electric Power Coal					15,821.2		15,821.2					1,511.7		1,511.7
U.S. Territory Coal (bit)						36.9	36.9						3.4	3.4
Natural Gas	**4,242.1**	**2,959.5**	**8,195.6**	**779.8**	**9,286.8**	**49.2**	**25,512.9**	**225.1**	**157.0**	**434.9**	**41.4**	**492.8**	**2.6**	**1,353.8**
Total Petroleum	**832.6**	**550.7**	**3,909.3**	**22,513.0**	**214.2**	**373.0**	**28,392.9**	**57.3**	**39.1**	**293.6**	**1,619.0**	**18.3**	**27.2**	**2,054.5**
Asphalt & Road Oil														
Aviation Gasoline				25.1			25.1				1.7			1.7
Distillate Fuel Oil	429.3	316.1	1,123.3	5,761.2	52.4	63.5	7,745.9	31.8	23.4	83.3	427.1	3.9	4.7	574.3
Jet Fuel				1,985.2	NA	39.1	2,024.3				143.4	NA	2.8	146.2
Kerosene	7.7	1.2	2.0			0.6	11.6	0.6	0.1	0.1			+	0.8
LPG (Propane)	395.6	135.5		7.1			538.2	24.9	8.5		0.4			33.8
HGL			280.1			11.1	291.2			17.9			0.7	18.6
Lubricants														
Motor Gasoline		66.1	432.2	14,523.3		131.4	15,153.0		4.7	30.7	1,030.4		9.3	1,075.1
Residual Fuel		31.4		211.1	76.7	127.3	446.5		2.4		15.8	5.8	9.6	33.5
Other Petroleum														
AvGas Blend Components			(+)				(+)			(+)				(+)
Crude Oil														
MoGas Blend Components														
Misc. Products														
Naphtha (<401 deg. F)														
Other Oil (>401 deg. F)														
Pentanes Plus			42.5				42.5			2.8				2.8
Petroleum Coke		0.4	649.0		85.1		734.4		+	66.3		8.7		75.0
Still Gas			1,320.2				1,320.2			88.1				88.1
Special Naphtha														
Unfinished Oils			60.1				60.1			4.5				4.5
Waxes														
Geothermal					**53.1**		**53.1**					**0.4**		**0.4**
Total (All Fuels)	**5,074.7**	**3,553.8**	**12,927.5**	**23,292.8**	**25,375.3**	**459.0**	**70,683.2**	**282.4**	**200.3**	**806.7**	**1,660.4**	**2,023.3**	**33.2**	**5,006.2**

Note: Parentheses indicate negative values.

+ Does not exceed 0.05 TBtu or 0.05 MMT CO_2 Eq.

NO (Not Occurring)

NA (Not Available)

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-25), and international bunker fuel consumption (see Table A-26).

[b] Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.

Table A-19: 2011 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (MMT CO_2 Eq.) from Energy Use						
Fuel Type	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**
Total Coal	**NO**	**61.7**	**905.8**	**NO**	**18,035.2**	**36.9**	**19,039.5**	**NO**	**5.8**	**86.0**	**NO**	**1,722.4**	**3.4**	**1,817.6**
Residential Coal	NO						NO	NO						NO
Commercial Coal		61.7					61.7		5.8					5.8
Industrial Other Coal			905.8				905.8			86.0				86.0
Transportation Coal				NO			NO				NO			NO
Electric Power Coal					18,035.2		18,035.2					1,722.4		1,722.4
U.S. Territory Coal (bit)						36.9	36.9						3.4	3.4
Natural Gas	**4,804.6**	**3,216.1**	**7,871.5**	**733.5**	**7,712.2**	**27.1**	**24,365.0**	**255.1**	**170.7**	**417.9**	**38.9**	**409.4**	**1.4**	**1,293.5**
Total Petroleum	**1,033.9**	**670.1**	**3,900.8**	**22,673.6**	**295.0**	**391.8**	**28,965.1**	**71.1**	**47.9**	**293.0**	**1,632.3**	**25.8**	**28.5**	**2,098.6**
Asphalt & Road Oil														
Aviation Gasoline				27.1			27.1				1.9			1.9
Distillate Fuel Oil	522.7	391.5	1,227.3	5,775.9	63.7	59.3	8,040.4	38.8	29.0	91.0	428.2	4.7	4.4	596.1
Jet Fuel				2,029.9	NA	47.1	2,077.0				146.6	NA	3.4	150.0
Kerosene	18.5	3.2	3.6			1.1	26.4	1.4	0.2	0.3			0.1	1.9
LPG (Propane)	492.6	142.5		7.3			642.4	31.0	9.0		0.5			40.4
HGL			159.6			9.0	168.7			10.2			0.6	10.8
Lubricants														
Motor Gasoline		79.0	455.9	14,575.5		147.7	15,258.1		5.6	32.4	1,035.7		10.5	1,084.2
Residual Fuel		53.7	46.9	258.0	93.1	127.5	579.2		4.0	3.5	19.4	7.0	9.6	43.5
Other Petroleum														
AvGas Blend Components			+				+			+				+
Crude Oil														
MoGas Blend Components														
Misc. Products														
Naphtha (<401 deg. F)														
Other Oil (>401 deg. F)														
Pentanes Plus			27.6				27.6			1.8				1.8
Petroleum Coke		0.2	600.3		138.3		738.8		+	61.3		14.1		75.4
Still Gas			1,323.4				1,323.4			88.3				88.3
Special Naphtha														
Unfinished Oils			56.1				56.1			4.2				4.2
Waxes														
Geothermal					**52.3**		**52.3**					**0.4**		**0.4**
Total (All Fuels)	**5,838.5**	**3,947.9**	**12,678.1**	**23,407.1**	**26,094.7**	**455.7**	**72,421.9**	**326.2**	**224.5**	**796.8**	**1,671.2**	**2,158.1**	**33.4**	**5,210.1**

+ Does not exceed 0.05 TBtu or 0.05 MMT CO_2 Eq.

NO (Not Occurring)

NA (Not Available)

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-25), and international bunker fuel consumption (see Table A-26).

[b] Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.

Table A-20: 2010 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (MMT CO_2 Eq.) from Energy Use						
Fuel Type	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**
Total Coal	**NO**	**69.7**	**993.0**	**NO**	**19,133.5**	**36.9**	**20,233.0**	**NO**	**6.6**	**94.2**	**NO**	**1,827.2**	**3.4**	**1,931.4**
Residential Coal	NO						NO	NO						NO
Commercial Coal		69.7					69.7		6.6					6.6
Industrial Other Coal			993.0				993.0			94.2				94.2
Transportation Coal				NO			NO				NO			NO
Electric Power Coal					19,133.5		19,133.5					1,827.2		1,827.2
U.S. Territory Coal (bit)						36.9	36.9						3.4	3.4
Natural Gas	**4,878.1**	**3,164.7**	**7,685.4**	**719.0**	**7,527.6**	**27.8**	**24,002.6**	**258.9**	**168.0**	**407.9**	**38.2**	**399.5**	**1.5**	**1,274.0**
Total Petroleum	**1,103.3**	**697.9**	**3,918.8**	**23,032.1**	**370.3**	**409.6**	**29,532.0**	**75.8**	**49.9**	**294.7**	**1,658.7**	**31.4**	**29.9**	**2,140.6**
Asphalt & Road Oil														
Aviation Gasoline				27.0			27.0				1.9			1.9
Distillate Fuel Oil	544.4	379.2	1,108.5	5,729.1	79.7	66.4	7,907.3	40.4	28.1	82.3	425.2	5.9	4.9	586.8
Jet Fuel				2,097.5	NA	36.6	2,134.0				151.5	NA	2.6	154.1
Kerosene	29.1	4.8	7.3			7.5	48.7	2.1	0.4	0.5			0.5	3.6
LPG (Propane)	529.8	140.0		7.5			677.3	33.3	8.8		0.5			42.6
HGL			148.0			17.6	165.5			9.5			1.1	10.6
Lubricants														
Motor Gasoline		111.8	559.7	14,898.8		112.9	15,683.2		7.9	39.8	1,059.3		8.0	1,115.0
Residual Fuel		61.7	32.2	272.2	154.1	168.7	688.8		4.6	2.4	20.4	11.6	12.7	51.7
Other Petroleum														
AvGas Blend Components			(0.2)				(0.2)			(+)				(+)
Crude Oil														
MoGas Blend Components														
Misc. Products														
Naphtha (<401 deg. F)														
Other Oil (>401 deg. F)														
Pentanes Plus			78.4				78.4			5.2				5.2
Petroleum Coke		0.3	633.0		136.6		770.0		+	64.6		13.9		78.6
Still Gas			1,324.0				1,324.0			88.3				88.3
Special Naphtha														
Unfinished Oils			28.0				28.0			2.1				2.1
Waxes														
Geothermal					**51.9**		**51.9**					**0.4**		**0.4**
Total (All Fuels)	**5,981.4**	**3,932.2**	**12,597.2**	**23,751.0**	**27,083.3**	**474.3**	**73,819.5**	**334.8**	**224.5**	**796.8**	**1,696.9**	**2,258.6**	**34.8**	**5,346.3**

Note: Parentheses indicate negative values.

+ Does not exceed 0.05 TBtu or 0.05 MMT CO_2 Eq.

NO (Not Occurring)

NA (Not Available)

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-25), and international bunker fuel consumption (see Table A-26).

[b] Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.

Table A-21: 2005 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (MMT CO_2 Eq.) from Energy Use						
Fuel Type	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**
Total Coal	**8.4**	**97.0**	**1,246.0**	**NO**	**20,737.2**	**32.7**	**22,121.4**	**0.8**	**9.3**	**117.8**	**NO**	**1,982.8**	**3.0**	**2,113.7**
Residential Coal	8.4						8.4	0.8						0.8
Commercial Coal		97.0					97.0		9.3					9.3
Industrial Other Coal			1,246.0				1,246.0			117.8				117.8
Transportation Coal				NO			NO				NO			NO
Electric Power Coal					20,737.2		20,737.2					1,982.8		1,982.8
U.S. Territory Coal (bit)						32.7	32.7						3.0	3.0
Natural Gas	**4,946.4**	**3,073.2**	**7,330.7**	**623.9**	**6,014.5**	**24.3**	**22,013.1**	**262.2**	**162.9**	**388.6**	**33.1**	**318.9**	**1.3**	**1,167.0**
Total Petroleum	**1,366.4**	**760.7**	**4,617.6**	**25,371.2**	**1,222.1**	**712.4**	**34,050.4**	**95.9**	**54.9**	**346.4**	**1,825.6**	**98.0**	**51.6**	**2,472.3**
Asphalt & Road Oil														
Aviation Gasoline				35.4			35.4				2.4			2.4
Distillate Fuel Oil	769.1	402.9	1,123.8	6,193.8	114.5	136.5	8,740.6	57.4	30.1	83.9	462.6	8.5	10.2	652.8
Jet Fuel				2,621.7	NA	65.5	2,687.2				189.3	NA	4.7	194.1
Kerosene	83.8	21.6	39.1			5.8	150.2	6.1	1.6	2.9			0.4	11.0
LPG (Propane)	513.5	131.6		28.2			673.3	32.3	8.3		1.8			42.3
HGL			281.9			73.6	355.4			18.0			4.7	22.7
Lubricants														
Motor Gasoline		88.6	689.5	16,235.7		200.2	17,213.9		6.3	48.8	1,150.1		14.2	1,219.4
Residual Fuel		115.8	237.4	256.4	876.5	230.9	1,717.0		8.7	17.8	19.3	65.8	17.3	128.9
Other Petroleum														
AvGas Blend Components			8.3				8.3			0.6				0.6
Crude Oil														
MoGas Blend Components														
Misc. Products														
Naphtha (<401 deg. F)														
Other Oil (>401 deg. F)														
Pentanes Plus			98.9				98.9			6.6				6.6
Petroleum Coke		0.3	706.6		231.1		938.0		+	72.1		23.6		95.8
Still Gas			1,429.4				1,429.4			95.4				95.4
Special Naphtha														
Unfinished Oils			2.8				2.8			0.2				0.2
Waxes														
Geothermal					**50.1**		**50.1**					**0.5**		**0.5**
Total (All Fuels)	**6,321.2**	**3,931.0**	**13,194.3**	**25,995.1**	**28,024.0**	**769.4**	**78,235.0**	**358.9**	**227.1**	**852.9**	**1,858.6**	**2,400.1**	**55.9**	**5,753.5**

+ Does not exceed 0.05 TBtu or 0.05 MMT CO_2 Eq.

NO (Not Occurring)

NA (Not Available)

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-25), and international bunker fuel consumption (see Table A-26).

[b] Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.

Table A-22: 2000 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (MMT CO_2 Eq.) from Energy Use						
Fuel Type	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**
Total Coal	**11.4**	**91.9**	**1,361.6**	**NO**	**20,220.2**	**4.6**	**21,689.6**	**1.1**	**8.8**	**128.5**	**NO**	**1,926.4**	**0.4**	**2,065.1**
Residential Coal	11.4						11.4	1.1						1.1
Commercial Coal		91.9					91.9		8.8					8.8
Industrial Other Coal			1,361.6				1,361.6			128.5				128.5
Transportation Coal				NO			NO				NO			NO
Electric Power Coal					20,220.2		20,220.2					1,926.4		1,926.4
U.S. Territory Coal (bit)						4.6	4.6						0.4	0.4
Natural Gas	**5,104.6**	**3,251.5**	**8,659.3**	**672.0**	**5,293.4**	**12.7**	**22,993.5**	**270.8**	**172.5**	**459.4**	**35.7**	**280.8**	**0.7**	**1,219.8**
Total Petroleum	**1,425.4**	**766.7**	**3,747.6**	**24,297.3**	**1,144.1**	**575.2**	**31,956.4**	**99.8**	**55.3**	**281.7**	**1,756.7**	**88.5**	**41.3**	**2,323.2**
Asphalt & Road Oil														
Aviation Gasoline				36.3			36.3				2.5			2.5
Distillate Fuel Oil	775.2	420.7	1,000.1	5,442.4	174.7	87.5	7,900.6	58.0	31.5	74.8	406.9	13.1	6.5	590.7
Jet Fuel				2,700.3	NA	68.6	2,768.9				195.0	NA	5.0	200.0
Kerosene	94.6	29.7	15.6			2.4	142.2	6.9	2.2	1.1			0.2	10.4
LPG (Propane)	555.6	150.6		11.9			718.1	34.9	9.5		0.7			45.1
HGL			393.8			91.8	485.6			25.3			5.9	31.2
Lubricants														
Motor Gasoline		74.1	249.9	15,663.0		186.3	16,173.3		5.3	17.8	1,118.2		13.3	1,154.6
Residual Fuel		91.6	184.1	443.5	870.8	138.6	1,728.5		6.9	13.8	33.3	65.4	10.4	129.8
Other Petroleum														
AvGas Blend Components			3.8				3.8			0.3				0.3
Crude Oil														
MoGas Blend Components														
Misc. Products														
Naphtha (<401 deg. F)														
Other Oil (>401 deg. F)														
Pentanes Plus			172.9				172.9			11.6				11.6
Petroleum Coke		0.2	697.3		98.6		796.2		+	71.2		10.1		81.3
Still Gas			1,431.2				1,431.2			95.5				95.5
Special Naphtha														
Unfinished Oils			(401.2)				(401.2)			(29.7)				(29.7)
Waxes														
Geothermal					**48.1**		**48.1**					**0.5**		**0.5**
Total (All Fuels)	**6,541.4**	**4,110.2**	**13,768.5**	**24,969.3**	**26,705.8**	**592.4**	**76,687.5**	**371.7**	**236.5**	**869.5**	**1,792.3**	**2,296.2**	**42.4**	**5,608.6**

Note: Parentheses indicate negative values.

+ Does not exceed 0.05 TBtu or 0.05 MMT CO_2 Eq.

NO (Not Occurring)

NA (Not Available)

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-25), and international bunker fuel consumption (see Table A-26).

[b] Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.

Table A-23: 1995 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (MMT CO_2 Eq.) from Energy Use						
Fuel Type	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**
Total Coal	**17.5**	**116.8**	**1,557.0**	**NO**	**17,466.3**	**4.7**	**19,162.2**	**1.7**	**11.2**	**147.2**	**NO**	**1,659.9**	**0.4**	**1,820.4**
Residential Coal	17.5						17.5	1.7						1.7
Commercial Coal		116.8					116.8		11.2					11.2
Industrial Other Coal			1,557.0				1,557.0			147.2				147.2
Transportation Coal				NO			NO				NO			NO
Electric Power Coal					17,466.3		17,466.3					1,659.9		1,659.9
U.S. Territory Coal (bit)						4.7	4.7						0.4	0.4
Natural Gas	**4,954.2**	**3,096.0**	**8,725.9**	**724.0**	**4,302.0**		**21,802.0**	**262.8**	**164.2**	**462.8**	**38.4**	**228.2**		**1,156.4**
Total Petroleum	**1,259.3**	**724.1**	**3,754.6**	**21,529.8**	**754.5**	**323.7**	**28,346.1**	**88.7**	**52.4**	**279.9**	**1,542.4**	**58.7**	**23.3**	**2,045.4**
Asphalt & Road Oil														
Aviation Gasoline				39.6			39.6				2.7			2.7
Distillate Fuel Oil	789.7	418.0	965.3	4,383.3	108.0	62.5	6,726.8	58.4	30.9	71.4	324.2	8.0	4.6	497.5
Jet Fuel				2,428.8	NA	57.2	2,486.0				172.2	NA	4.1	176.3
Kerosene	74.3	22.1	15.4			2.0	113.9	5.4	1.6	1.1			0.1	8.3
LPG (Propane)	395.3	108.9		17.8			521.9	24.9	6.8		1.1			32.8
HGL			277.8			35.6	313.5			17.8			2.3	20.1
Lubricants														
Motor Gasoline		33.5	370.4	14,273.1		84.5	14,761.5		2.4	26.3	1,013.1		6.0	1,047.7
Residual Fuel		141.5	286.2	387.3	566.0	81.9	1,462.8		10.6	21.5	29.1	42.5	6.1	109.8
Other Petroleum														
AvGas Blend Components			5.3				5.3			0.4				0.4
Crude Oil			14.5				14.5			1.1				1.1
MoGas Blend Components														
Misc. Products														
Naphtha (<401 deg. F)														
Other Oil (>401 deg. F)														
Pentanes Plus			170.3				170.3			11.4				11.4
Petroleum Coke		0.1	600.7		80.6		681.4		+	61.3		8.2		69.6
Still Gas			1,369.5				1,369.5			91.4				91.4
Special Naphtha														
Unfinished Oils			(320.9)				(320.9)			(23.8)				(23.8)
Waxes														
Geothermal					**45.6**		**45.6**					**0.4**		**0.4**
Total (All Fuels)	**6,231.0**	**3,936.9**	**14,037.5**	**22,253.7**	**22,568.4**	**328.4**	**69,355.9**	**353.1**	**227.8**	**889.9**	**1,580.8**	**1,947.2**	**23.7**	**5,022.5**

Note: Parentheses indicate negative values.

+ Does not exceed 0.05 TBtu or 0.05 MMT CO_2 Eq.

NO (Not Occurring)

NA (Not Available)

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-25), and international bunker fuel consumption (see Table A-26).

[b] Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.

Table A-24: 1990 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (MMT CO_2 Eq.) from Energy Use						
Fuel Type	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**
Total Coal	**31.1**	**124.5**	**1,668.2**	**NO**	**16,261.0**	**5.4**	**18,090.1**	**3.0**	**12.0**	**157.8**	**NO**	**1,546.5**	**0.5**	**1,719.8**
Residential Coal	31.1						31.1	3.0						3.0
Commercial Coal		124.5					124.5		12.0					12.0
Industrial Other Coal			1,668.2				1,668.2			157.8				157.8
Transportation Coal				NO			NO				NO			NO
Electric Power Coal					16,261.0		16,261.0					1,546.5		1,546.5
U.S. Territory Coal (bit)						5.4	5.4						0.5	0.5
Natural Gas	**4,486.6**	**2,679.6**	**7,712.8**	**679.2**	**3,308.5**		**18,866.7**	**237.8**	**142.0**	**408.8**	**36.0**	**175.4**		**1,000.0**
Total Petroleum	**1,375.8**	**1,022.6**	**3,846.2**	**19,977.2**	**1,289.4**	**294.8**	**27,805.9**	**97.8**	**74.3**	**287.2**	**1,433.1**	**97.5**	**21.2**	**2,011.2**
Asphalt & Road Oil														
Aviation Gasoline				45.0			45.0				3.1			3.1
Distillate Fuel Oil	959.3	525.5	1,098.3	3,554.8	96.5	56.4	6,290.8	70.9	38.9	81.2	262.9	7.1	4.2	465.2
Jet Fuel				2,590.1	NA	48.6	2,638.7				184.2	NA	3.5	187.7
Kerosene	63.9	11.8	12.3			2.0	90.0	4.7	0.9	0.9			0.1	6.6
LPG (Propane)	352.6	102.4		22.9			477.9	22.2	6.4		1.4			30.0
HGL			227.1			33.4	260.5			14.6			2.1	16.7
Lubricants														
Motor Gasoline		153.0	254.8	13,464.1		75.9	13,947.7		10.9	18.1	958.9		5.4	993.3
Residual Fuel		229.8	364.1	300.3	1,162.6	78.5	2,135.3		17.3	27.3	22.6	87.3	5.9	160.3
Other Petroleum														
AvGas Blend Components			0.2				0.2			+				+
Crude Oil			50.9				50.9			3.8				3.8
MoGas Blend Components			53.7				53.7			3.8				3.8
Misc. Products														
Naphtha (<401 deg. F)														
Other Oil (>401 deg. F)														
Pentanes Plus			126.1				126.1			8.4				8.4
Petroleum Coke			591.2		30.4		621.5			60.4		3.1		63.5
Still Gas			1,436.5				1,436.5			95.8				95.8
Special Naphtha														
Unfinished Oils			(369.0)				(369.0)			(27.3)				(27.3)
Waxes														
Geothermal					**52.7**		**52.7**					**0.5**		**0.5**
Total (All Fuels)	**5,893.5**	**3,826.6**	**13,227.1**	**20,656.4**	**20,911.6**	**300.2**	**64,815.4**	**338.6**	**228.3**	**853.8**	**1,469.1**	**1,820.0**	**21.7**	**4,731.5**

Note: Parentheses indicate negative values.

+ Does not exceed 0.05 TBtu or 0.05 MMT CO_2 Eq.

NO (Not Occurring)

NA (Not Available)

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-25), and international bunker fuel consumption (see Table A-26).

[b] Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.

Table A-25: Unadjusted Non-Energy Fuel Consumption (TBtu)

Sector/Fuel Type	1990	1995	2000	2005	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Industry	**4,644.2**	**5,153.6**	**5,575.9**	**5,482.5**	**4,735.1**	**4,663.1**	**4,599.2**	**4,829.2**	**4,724.8**	**5,022.6**	**5,106.3**	**5,378.9**	**5,789.2**	**5,897.1**
Industrial Coking Coal	0.0	37.8	53.5	80.4	64.8	60.8	132.5	119.9	49.3	122.4	89.6	113.0	124.8	132.1
Industrial Other Coal	7.6	10.5	11.5	11.0	9.6	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5
Natural Gas to Chemical Plants, Other Uses	305.9	371.0	401.7	270.4	310.0	314.0	319.3	324.6	330.6	431.8	532.0	631.1	730.8	730.8
Asphalt & Road Oil	1,170.2	1,178.2	1,275.7	1,323.2	877.8	859.5	826.7	783.3	792.6	831.7	853.4	849.2	792.8	843.9
HGL	1,302.2	1,651.6	1,759.3	1,659.5	1,899.9	1,954.4	1,983.7	2,155.2	2,142.8	2,216.8	2,257.1	2,329.7	2,677.4	2,758.8
Lubricants	186.3	177.8	189.9	160.2	135.9	127.4	118.3	125.1	130.7	142.1	135.1	124.9	121.9	117.6
Pentanes Plus	125.2	169.0	171.6	98.1	77.7	27.3	42.2	47.1	44.2	80.2	56.1	86.4	111.8	166.6
Naphtha (<401 deg. F)	347.8	373.0	613.5	698.7	490.6	487.3	453.9	517.8	442.6	428.1	420.0	436.2	447.1	396.7
Other Oil (>401 deg. F)	753.9	801.0	722.2	708.0	452.5	388.5	287.2	223.9	247.2	229.0	222.5	262.9	239.1	234.1
Still Gas	36.7	47.9	17.0	67.7	147.8	163.6	160.6	166.7	164.5	162.2	166.1	163.8	166.9	158.7
Petroleum Coke	123.1	120.6	98.7	186.9	61.0	62.4	67.8	62.4	61.4	62.5	61.2	57.0	58.9	56.4
Special Naphtha	107.1	70.8	97.4	62.5	26.1	22.6	14.7	100.0	106.1	99.3	93.6	100.3	92.0	95.6
Other (Wax/Misc.)														
Distillate Fuel Oil	7.0	6.8	11.7	11.7	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8
Waxes	33.3	40.6	33.1	31.4	17.1	15.1	15.3	16.5	14.8	12.4	12.8	10.2	12.4	10.4
Miscellaneous Products	137.8	97.1	119.2	112.8	158.7	164.7	161.6	171.2	182.7	188.9	191.3	198.8	198.0	180.2
Transportation	**176.0**	**167.9**	**179.4**	**151.3**	**154.8**	**148.4**	**135.4**	**143.4**	**149.4**	**162.8**	**154.4**	**142.0**	**137.0**	**132.1**
Lubricants	176.0	167.9	179.4	151.3	154.8	148.4	135.4	143.4	149.4	162.8	154.4	142.0	137.0	132.1
U.S. Territories	**50.8**	**55.4**	**140.8**	**114.9**	**27.4**	**14.6**	**17.6**	**10.5**	**10.7**	**10.3**	**10.5**	**10.7**	**10.7**	**10.7**
Lubricants	0.7	2.0	3.1	4.6	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Other Petroleum (Misc. Prod.)	50.1	53.4	137.7	110.3	26.4	13.6	16.6	9.5	9.6	9.3	9.5	9.6	9.6	9.6
Total	**4,871.1**	**5,377.0**	**5,896.1**	**5,748.7**	**4,917.3**	**4,826.1**	**4,752.2**	**4,983.1**	**4,884.9**	**5,195.8**	**5,271.1**	**5,531.5**	**5,936.9**	**6,039.9**

Note: These values are unadjusted non-energy fuel use provided by EIA. They have not yet been adjusted to remove petroleum feedstock exports and processes accounted for in the Industrial Processes and Product Use chapter.

Table A-26: International Bunker Fuel Consumption (TBtu)

Fuel Type	1990	1995	2000	2005	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Aviation Jet Fuel	539.4	703.4	880.1	853.1	865.4	919.9	916.3	931.6	987.8	1,022.3	1,051.1	1,103.2	1,146.8	1,146.1
Marine Residual Fuel Oil	715.7	523.2	444.1	581.0	619.8	518.4	459.5	379.8	369.2	406.8	450.7	445.3	417.6	336.2
Marine Distillate Fuel Oil	158.0	125.7	85.9	126.9	128.2	107.4	91.7	75.4	82.0	113.5	117.5	121.3	134.4	136.3
Total	**1,413.1**	**1,352.3**	**1,410.0**	**1,561.0**	**1,613.4**	**1,545.7**	**1,467.4**	**1,386.9**	**1,439.0**	**1,542.6**	**1,619.3**	**1,669.9**	**1,698.8**	**1,618.6**

Note: Further information on the calculation of international bunker fuel consumption of aviation jet fuel is provided in Annex 3.3 Methodology for Estimating Emissions from Commercial Aircraft Jet Fuel Consumption.

Table A-27: Key Assumptions for Estimating CO_2 Emissions

Fuel Type	C Content Coefficient (MMT C/QBtu)
Coal	
Residential Coal	(See footnote b)
Commercial Coal	(See footnote b)
Industrial Coking Coal	(See footnote b)
Industrial Other Coal	(See footnote b)
Electric Power Coal	(See footnote b)
U.S. Territory Coal (bit)	25.14
Natural Gas	
Pipeline Natural Gas	(See footnote b)
Petroleum	
Asphalt & Road Oil	20.55
Aviation Gasoline	18.86
Distillate Fuel Oil No. 1	19.98
Distillate Fuel Oil No. 2[a]	(See footnote b)
Distillate Fuel Oil No. 4	20.47
Jet Fuel	(See footnote b)
Kerosene	19.96
LPG (Propane)	17.15
HGL (Energy Use)	(See footnote b)
HGL (Non-Energy Use)	(See footnote b)
Lubricants	20.20
Motor Gasoline	(See footnote b)
Residual Fuel Oil No. 5	19.89
Residual Fuel Oil No. 6[a]	20.48
Other Petroleum	
AvGas Blend Components	18.87
Crude Oil	(See footnote b)
MoGas Blend Components	(See footnote b)
Misc. Products	(See footnote b)
Misc. Products (Territories)	20.00
Naphtha (<401 deg. F)	18.55
Other Oil (>401 deg. F)	20.17
Pentanes Plus	18.24
Petroleum Coke	27.85
Still Gas	18.20
Special Naphtha	19.74
Unfinished Oils	(See footnote b)
Waxes	19.80
Geothermal	
Flash Steam	2.18
Dry Steam	3.22
Binary	0.00
Binary/Flash Steam	0.00

[a] Distillate fuel oil No. 2 and residual fuel oil No. 6 are used in the CO_2 from fossil fuel combustion calculations, and other oil types are presented for informational purposes only. An additional discussion on the derivation of these carbon content coefficients is presented in Annex 2.2.

[b] These coefficients vary annually due to fluctuations in fuel quality (see Table A-28).

Sources: C coefficients from EIA (2009), EPA (2010), and EPA (2020).

Table A-28: Annually Variable C Content Coefficients by Year (MMT C/QBtu)

Fuel Type	1990	1995	2000	2005	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential Coal[a]	26.19	26.13	26.00	26.04	25.75	25.81	25.88	25.90	25.88	25.98	26.01	26.09	26.09	26.11
Commercial Coal	26.19	26.13	26.00	26.04	25.75	25.81	25.88	25.90	25.88	25.98	26.01	26.09	26.09	26.11
Industrial Coking Coal	25.53	25.57	25.63	25.60	25.58	25.57	25.57	25.58	25.57	25.57	25.57	25.56	25.59	25.59
Industrial Other Coal	25.81	25.79	25.74	25.79	25.86	25.88	25.94	25.93	25.95	26.00	26.03	26.06	26.08	26.07
Electric Power Coal	25.94	25.92	25.98	26.08	26.05	26.05	26.06	26.05	26.04	26.07	26.06	26.08	26.09	26.08
Pipeline Natural Gas	14.46	14.47	14.47	14.46	14.48	14.48	14.47	14.46	14.45	14.43	14.43	14.43	14.43	14.43
HGL (Energy Use)	17.51	17.51	17.52	17.45	17.43	17.40	17.41	17.39	17.41	17.43	17.43	17.45	17.45	17.47
HGL (Non-Energy Use)	17.24	17.25	17.22	17.19	16.93	16.84	16.86	16.88	16.86	16.89	16.85	16.84	16.82	16.85
Motor Gasoline	19.42	19.36	19.47	19.32	19.39	19.38	19.35	19.28	19.26	19.25	19.27	19.28	19.27	19.27
Jet Fuel	19.40	19.34	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70
MoGas Blend Components	19.42	19.36	19.33	19.36	19.46	19.46	19.46	19.46	19.46	19.46	19.46	19.46	19.46	19.46
Misc. Products	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Unfinished Oils	20.15	20.21	20.22	20.31	20.31	20.31	20.31	20.31	20.31	20.31	20.31	20.31	20.31	20.31
Crude Oil	20.15	20.21	20.22	20.31	20.31	20.31	20.31	20.31	20.31	20.31	20.31	20.31	20.31	20.31
Distillate Fuel Oil No. 2	20.17	20.17	20.39	20.37	20.24	20.22	20.22	20.23	20.23	20.22	20.21	20.20	20.22	20.22

[a] EIA discontinued collection of residential sector coal consumption data in 2008, because consumption of coal in the residential sector is extremely limited. Therefore, the number cited here is developed from commercial/institutional consumption.

Source: Coal C content coefficients calculated from USGS (1998), PSU (2010), Gunderson (2019), IGS (2019), ISGS (2019), EIA (1990 through 2001), EIA (2001 through 2020a), and EIA (2001 through 2020b); pipeline natural gas C content coefficients calculated from EIA (2020b) and EPA (2010); petroleum carbon contents from EPA (2010), EIA (1994), EIA (2009), EPA (2020), and ICF (2020). See Annex 2.2 for information on how these C content coefficients are calculated.

Table A-29: Electricity Consumption by End-Use Sector (Billion Kilowatt-Hours)

End-Use Sector	1990	1995	2000	2005	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential	924	1,043	1,192	1,359	1,446	1,423	1,374	1,394	1,407	1,403	1,410	1,377	1,466	1,437
Commercial	838	953	1,159	1,275	1,330	1,328	1,327	1,337	1,352	1,361	1,367	1,353	1,381	1,360
Industrial	1,070	1,163	1,235	1,169	1,103	1,124	1,123	1,129	1,136	1,128	1,117	1,125	1,145	1,146
Transportation[a]	5	5	5	8	8	8	8	8	9	9	9	10	11	12
Total	**2,837**	**3,164**	**3,592**	**3,811**	**3,887**	**3,883**	**3,832**	**3,868**	**3,903**	**3,900**	**3,902**	**3,864**	**4,003**	**3,954**

Note: Does not include the U.S. Territories.

[a] Includes electricity used for electric vehicle charging in the residential and commercial sectors.

Source: Retail sales of electricity to end-users obtained from EIA (2020b). Industrial electricity consumption includes direct use.

Table A-30: Electric Power Generation by Fuel Type (Percent)

Fuel Type	1990	1995	2000	2005	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Coal	54.1%	52.7%	53.3%	51.1%	46.0%	43.5%	38.6%	40.2%	39.9%	34.2%	31.4%	30.9%	28.4%	24.2%
Natural Gas	10.7%	13.1%	14.2%	17.5%	22.7%	23.5%	29.1%	26.4%	26.3%	31.6%	32.7%	30.9%	34.0%	37.3%
Nuclear	19.9%	21.1%	20.7%	20.0%	20.3%	20.0%	19.8%	20.2%	20.3%	20.4%	20.6%	20.8%	20.1%	20.4%
Renewables	11.3%	10.9%	8.8%	8.3%	10.0%	12.2%	11.9%	12.5%	12.8%	13.0%	14.7%	16.8%	16.8%	17.6%
Petroleum	4.1%	2.1%	2.9%	3.0%	0.9%	0.7%	0.5%	0.6%	0.7%	0.7%	0.6%	0.5%	0.6%	0.4%
Other Gases[a]	+%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Net Electricity Generation (Billion kWh)[b]	*2,905*	*3,197*	*3,643*	*3,902*	*3,971*	*3,947*	*3,888*	*3,901*	*3,936*	*3,917*	*3,917*	*3,877*	*4,017*	*3,962*

Note: Does not include electricity generation from purchased steam as the fuel used to generate the steam cannot be determined. Does not include non-renewable waste (i.e., municipal solid waste from non-biogenic sources, and tire-derived fuels).

Source: EIA (2020b).

+ Does not exceed 0.05 percent.

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

[b] Represents net electricity generation from the electric power sector. Excludes net electricity generation from commercial and industrial combined-heat-and-power and electricity-only plants. Net electricity generation differs from the total presented in Table A-29 (i.e., end-use consumption of electricity) due to electricity transmitted across U.S. borders, as well as transmission and distribution losses.

Table A-31: Geothermal Net Generation by Geotype (Billion Kilowatt-Hours)

Geotype	1990	1995	2000	2005	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Binary	0.08	0.28	0.24	0.68	2.41	2.16	2.43	2.75	3.12	3.36	3.62	3.56	3.84	4.34
Flash Steam	6.15	7.63	7.43	7.93	6.83	7.17	7.02	7.03	6.92	7.00	6.65	6.69	6.39	5.92
Dry Steam	9.21	5.47	6.43	6.09	5.98	5.98	6.11	6.00	5.84	5.56	5.55	5.67	5.73	5.21
Total	**15.43**	**13.38**	**14.09**	**14.69**	**15.22**	**15.32**	**15.56**	**15.77**	**15.88**	**15.92**	**15.83**	**15.93**	**15.97**	**15.47**

Source: EIA (2020a).

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2.2. Methodology for Estimating the Carbon Content of Fossil Fuels

This sub-annex presents the background and methodology for estimating the carbon (C) content of fossil fuels combusted in the United States. The C content of a particular fossil fuel represents the maximum potential emissions to the atmosphere if all C in the fuel is oxidized during combustion. The C content coefficients used in this report were developed using methods first outlined in the U.S. Energy Information Administration's (EIA) *Emissions of Greenhouse Gases in the United States: 1987-1992* (1994) and were developed primarily by EIA. EPA has updated many of the C content coefficients based on carbon dioxide (CO_2) emission factors developed for the Mandatory Reporting of Greenhouse Gases Rule, signed in September 2009 (EPA 2009b, 2010). In addition, EPA has revised many of the C content coefficients to vary annually across the time series to account for the annual variability in carbon content (or composition) of each fuel type as it is consumed in the United States (ICF 2020; USGS 1998; PSU 2010; Gunderson 2019; IGS 2019; ISGS 2019; Martel and Angello 1977; ASTM 1985; NIPER 1990 through 2009; Green & Perry ed. 2008; Wauquier ed. 1995; EPA (2009b; 2010; 2013; 2020b); and EIA (1994; 2008a; 2009a; 2010; 2020c; 1990 through 2001; 2001 through 2020a; 2001 through 2020b)). This sub-annex presents a time-series analysis of changes in U.S. C content coefficients for coal, petroleum products, and natural gas. A summary of C content coefficients used in this report appears in Table A-32.

Though the methods for estimating C contents for coal, natural gas, and petroleum products differ in their details, they each follow the same basic approach. First, because C coefficients are presented in terms of mass per unit energy (i.e., million metric tons C per quadrillion Btu or MMT C/QBtu), those fuels that are typically described in volumetric units (i.e., petroleum products and natural gas) are converted to units of mass using an estimated density. Second, C contents are derived from fuel sample data, using descriptive statistics to estimate the C share of the fuel by weight. The heat content of the fuel is then estimated based on the sample data, or where sample data are unavailable or unrepresentative, by default values that reflect the characteristics of the fuel as defined by market requirements. A discussion of each fuel appears below.

The C content of coal is described first; approximately one-quarter of all U.S. C emissions from fossil fuel combustion are associated with coal consumption. The methods and sources for estimating the C content of natural gas are provided next. Approximately one-third of U.S. greenhouse gas emissions from fossil fuel combustion are attributable to natural gas consumption. Finally, this sub-annex examines C contents of petroleum products. U.S. energy use statistics account for more than 20 different petroleum products.

Table A-32: Carbon Content Coefficients Used in this Report (MMT Carbon/QBtu)

Fuel Type	1990	1995	2000	2005	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Coal														
Residential Coal[a,b]	26.19	26.13	26.00	26.04	25.75	25.81	25.88	25.90	25.88	25.98	26.01	26.09	26.09	26.11
Commercial Coal[a]	26.19	26.13	26.00	26.04	25.75	25.81	25.88	25.90	25.88	25.98	26.01	26.09	26.09	26.11
Industrial Coking Coal[a]	25.53	25.57	25.63	25.79	25.58	25.57	25.57	25.58	25.57	25.57	25.57	25.56	25.59	25.59
Industrial Other Coal[a]	25.81	25.79	25.74	26.08	25.86	25.88	25.94	25.93	25.95	26.00	26.03	26.06	26.08	26.07
Utility Coal[a,c]	25.94	25.92	25.98	26.04	26.05	26.05	26.06	26.05	26.04	26.07	26.06	26.08	26.09	26.08
Pipeline Natural Gas[d]	**14.46**	**14.47**	**14.47**	**14.46**	**14.48**	**14.48**	**14.47**	**14.46**	**14.45**	**14.43**	**14.43**	**14.43**	**14.43**	**14.43**
Petroleum														
Asphalt and Road Oil	20.55	20.55	20.55	20.55	20.55	20.55	20.55	20.55	20.55	20.55	20.55	20.55	20.55	20.55
Aviation Gasoline	18.86	18.86	18.86	18.86	18.86	18.86	18.86	18.86	18.86	18.86	18.86	18.86	18.86	18.86
Distillate Fuel Oil No. 2	20.17	20.17	20.39	20.37	20.24	20.22	20.22	20.23	20.23	20.22	20.21	20.20	20.22	20.22
Jet Fuel[a]	19.40	19.34	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70
Kerosene	19.96	19.96	19.96	19.96	19.96	19.96	19.96	19.96	19.96	19.96	19.96	19.96	19.96	19.96
LPG (Propane)	17.15	17.15	17.15	17.15	17.15	17.15	17.15	17.15	17.15	17.15	17.15	17.15	17.15	17.15
HGL (Energy Use)[d]	17.51	17.51	17.52	17.45	17.43	17.40	17.41	17.39	17.41	17.43	17.43	17.45	17.45	17.47
HGL (Non-Energy Use)[d]	17.24	17.25	17.22	17.19	16.93	16.84	16.86	16.88	16.86	16.89	16.85	16.84	16.82	16.85
Lubricants	20.20	20.20	20.20	20.20	20.20	20.20	20.20	20.20	20.20	20.20	20.20	20.20	20.20	20.20
Motor Gasoline[d]	19.42	19.36	19.47	19.32	19.39	19.38	19.35	19.28	19.26	19.25	19.27	19.28	19.27	19.27
Residual Fuel No. 6	20.48	20.48	20.48	20.48	20.48	20.48	20.48	20.48	20.48	20.48	20.48	20.48	20.48	20.48
Other Petroleum														
Av. Gas Blend Comp.	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87
Mo. Gas Blend Comp[c]	19.42	19.36	19.33	19.36	19.46	19.46	19.46	19.46	19.46	19.46	19.46	19.46	19.46	19.46
Crude Oil[d]	20.15	20.21	20.22	20.31	20.31	20.31	20.31	20.31	20.31	20.31	20.31	20.31	20.31	20.31
Misc. Products[e]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Petroleum Liquids	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
Naphtha (<401 deg. F)	18.55	18.55	18.55	18.55	18.55	18.55	18.55	18.55	18.55	18.55	18.55	18.55	18.55	18.55
Other Oil (>401 deg. F)	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17
Pentanes Plus	18.24	18.24	18.24	18.24	18.24	18.24	18.24	18.24	18.24	18.24	18.24	18.24	18.24	18.24
Petroleum Coke	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85
Still Gas	18.20	18.20	18.20	18.20	18.20	18.20	18.20	18.20	18.20	18.20	18.20	18.20	18.20	18.20
Special Naphtha	19.74	19.74	19.74	19.74	19.74	19.74	19.74	19.74	19.74	19.74	19.74	19.74	19.74	19.74
Unfinished Oils[d]	20.15	20.21	20.22	20.31	20.31	20.31	20.31	20.31	20.31	20.31	20.31	20.31	20.31	20.31
Waxes	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80
Geothermal[f]														
Flash	2.18	2.18	2.18	2.18	2.18	2.18	2.18	2.18	2.18	2.18	2.18	2.18	2.18	2.18
Steam	3.22	3.22	3.22	3.22	3.22	3.22	3.22	3.22	3.22	3.22	3.22	3.22	3.22	3.22

[a] C contents vary annually based on changes in annual mix of production and end-use consumption of coal from each producing state.

[b] EIA discontinued collection of residential sector coal consumption data in 2008, because consumption of coal in the residential sector is extremely limited. Therefore, starting in 2008, the number cited here is developed from commercial/institutional consumption.

[c] Content for utility coal used in the electric power calculations. All coefficients based on higher heating value. Higher heating value (gross heating value) is the total amount of heat released when a fuel is burned. Coal, crude oil, and natural gas all include chemical compounds of carbon and hydrogen. When those fuels are burned, the carbon and hydrogen combine with oxygen in the air to produce CO_2 and water. Some of the energy released in burning goes into transforming the water into steam and is usually lost. The amount of heat spent in transforming the water into steam is counted as part of gross heat content. Lower heating value (net heating value), in contrast, does not include the heat spent in transforming the water into steam. Using a simplified methodology based on International Energy Agency defaults, higher heating value can be converted to lower heating value for coal and petroleum products by multiplying by 0.95 and for natural gas by multiplying by 0.90. Carbon content coefficients are presented in higher heating value because U.S. energy statistics are reported by higher heating value.

[d] C contents vary annually based on changes in fuel composition.

[e] The miscellaneous products category reported by EIA is assumed to be mostly petroleum refinery sulfur compounds that do not contain carbon (EIA 2019).

[f] C contents based on geotype (i.e., flash steam and dry steam) were obtained from EPA's *Emissions & Generation Resource Integrated Database (eGRID) 2018 Technical Support Document* (EPA 2020a). C contents were obtained in pounds CO_2/megawatt hour and were applied to net generation by geotype (in megawatt hours) from EIA (2020a). C contents were converted to MMT Carbon/QBtu in this table. C contents for binary and binary/flash geotypes are zero and have been excluded from this table.

Coal

Although the IPCC (2006) guidelines provide C contents for coal according to rank, it was necessary to develop C content coefficients by consuming sector to match the format in which coal consumption is reported by EIA. Because the C content of coal varies by the state in which it was mined and by coal rank, and because the sources of coal for each consuming sector vary by year, the weighted average C content for coal combusted in each consuming sector also varies over time. A time series of C contents by coal rank and consuming sector appears in Table A-33.[12]

Methodology

The methodology for developing C contents for coal by consuming sector consists of four steps. An additional step has been taken to calculate C contents by coal rank to facilitate comparison with IPCC default values.

Step 1: Determine Carbon Contents by Rank and by State of Origin

Carbon contents by rank and state of origin are estimated on the basis of 8,672 coal samples, 6,588 of which were collected by the U.S. Geological Survey (USGS) (1998), 504 samples that come from the Pennsylvania State University database (PSU 2010), and the remainder from individual State Geological Surveys. Samples obtained directly from individual State Geological Surveys include 908 samples from the Montana Bureau of Mines & Geology (Gunderson 2019), 745 samples from the Indiana Geological Survey Coal Quality Database (IGS 2019), and 460 samples from the Illinois State Geological Survey (ISGS 2019). Because the data obtained directly from the State Geological Surveys for these three states included both samples collected by the USGS and additional samples, these data were used to determine C content coefficients for these states instead of the USGS and Pennsylvania State University data.

These coal samples are classified according to rank and state of origin. For each rank in each state, the average heat content and C content of the coal samples are calculated based on the proximate (heat) and ultimate (percent carbon) analyses of the samples. Dividing the C content (reported in pounds of CO_2) by the heat content (reported in million Btu or MMBtu) yields an average C content coefficient. This coefficient is then converted into units of MMT C/QBtu.

Step 2: Determine Weighted Average Carbon Content by State

Carbon contents by rank and origin calculated in Step 1 are then weighted by the annual share of state production that was each rank. State production by rank is obtained from the EIA. This step yields a single carbon content per state that varies annually based on production by coal type. However, most coal-producing states produce only one rank of coal. For these states the weighted factor equals the carbon content calculated in Step 1 and is constant across the time series.

Step 3: Allocate Sectoral Consumption by State of Origin

U.S. energy statistics[13] through 2019 provide data on the origin of coal used in four areas: 1) the electric power industry, 2) industrial coking, 3) all other industrial uses, and 4) the residential and commercial end-use sectors.[14] Because U.S. energy statistics do not provide the distribution of coal rank consumed by each consuming sector, it is assumed that each sector consumes a representative mixture of coal ranks from a particular state that matches the mixture of all coal produced in that state during the year. Thus, the weighted state-level factor developed in Step 2 is applied.

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[12] For a comparison to earlier estimated carbon contents see *Chronology and Explanation of Changes in Individual Carbon Content Coefficients of Fossil Fuels* near the end of this Annex.

[13] U.S. Energy Information Administration (EIA). *Annual Coal Distribution Report* (2001-2019b); *Coal Industry Annual* (1990-2001).

[14] In 2008, EIA began collecting and reporting data on commercial and institutional coal consumption, rather than residential and commercial consumption. Thus, the residential/commercial coal coefficient reported in Table A-32 for 2009 to the present represents the mix of coal consumed by commercial and institutional users. Currently, only an extremely small amount of coal is consumed in the U.S. residential sector.

Step 4: Weight Sectoral Carbon Contents to Reflect the Rank and State of Origin of Coal Consumed

Sectoral C contents are calculated by multiplying the share of coal purchased from each state by the state's weighted C content estimated in Step 2. The resulting partial C contents are then totaled across all states to generate a national sectoral C content.

$$C_{sector} = S_{state1} \times C_{state1} + S_{state2} \times C_{state2} + \ldots + S_{state50} \times C_{state50}$$

where,

C_{sector} = The C content by consuming sector;
S_{state} = The portion of consuming sector coal consumption attributed to production from a given state;
C_{state} = The estimated weighted C content of all ranks produced in a given state.

Table A-33: Carbon Content Coefficients for Coal by Consuming Sector and Coal Rank (MMT C/QBtu) (1990-2019)

Consuming Sector	**1990**	**1995**	**2000**	**2005**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Electric Power	25.94	25.92	25.98	26.08	26.05	26.05	26.06	26.05	26.04	26.07	26.06	26.08	26.09	26.08
Industrial Coking	25.53	25.57	25.63	25.60	25.58	25.57	25.57	25.58	25.57	25.57	25.57	25.56	25.59	25.59
Other Industrial	25.81	25.79	25.74	25.79	25.86	25.88	25.94	25.93	25.95	26.00	26.03	26.06	26.08	26.07
Residential/ Commercial[a]	26.19	26.13	26.00	26.04	25.75	25.81	25.88	25.90	25.88	25.98	26.01	26.09	26.09	26.11
Coal Rank[b]														
Anthracite	28.28	28.28	28.28	28.28	28.28	28.28	28.28	28.28	28.28	28.28	28.28	28.28	28.28	28.28
Bituminous	25.38	25.42	25.45	25.45	25.42	25.42	25.41	25.41	25.41	25.40	25.40	25.40	25.41	25.41
Sub-bituminous	26.46	26.47	26.46	26.48	26.47	26.49	26.49	26.49	26.49	26.49	26.49	26.20	26.49	26.49
Lignite	26.58	26.59	26.61	26.62	26.63	26.61	26.61	26.62	26.63	26.66	26.64	26.67	26.76	26.75

[a] In 2008, EIA began collecting consumption data for commercial and institutional consumption rather than commercial and residential consumption.

[b] Emission factors for coal rank are weighted based on production in each state.

Sources: C content coefficients calculated from USGS (1998), PSU (2010), Gunderson (2019), IGS (2019), ISGS (2019), EIA (1990 through 2001; 2001 through 2020a; 2001 through 2020b).

Step 5: Develop National-Level Carbon Contents by Rank for Comparison to IPCC Defaults

Although not used to calculate emissions, national-level C contents by rank are more easily compared to C contents of other countries than are sectoral C contents. This step requires weighting the state-level C contents by rank developed under Step 1 by overall coal production by state and rank. Each state-level C content by rank is multiplied by the share of national production of that rank that each state represents. The resulting partial C contents are then summed across all states to generate an overall C content for each rank.

$$N_{rank} = P_{rank1} \times C_{rank1} + P_{rank2} \times C_{rank2} + \ldots + P_{rankn} \times C_{rankn}$$

where,

N_{rank} = The national C content by rank;
P_{rank} = The portion of U.S. coal production of a given rank attributed to each state; and
C_{rank} = The estimated C content of a given rank in each state.

Data Sources

The ultimate analysis of coal samples was based on 8,672 coal samples, 6,588 of which are from USGS (1998), 504 from the Pennsylvania State University Coal Database (PSU 2010), and the remainder from individual State Geological Surveys. Samples obtained directly from individual State Geological Surveys include 908 samples from the Montana Bureau of Mines & Geology (Gunderson 2019), 745 samples from the Indiana Geological Survey Coal Quality Database (IGS 2019), and 460 samples from the Illinois State Geological Survey (ISGS 2019). Because the data obtained directly from the State Geological Surveys for these three states included both samples collected by the USGS and additional samples, these data were used to determine C content coefficients for these states instead of the USGS and Pennsylvania State University data. Data contained in the USGS's CoalQual Database are derived primarily from samples taken between 1973 and 1989, and were largely reported in State Geological Surveys. Data in the PSU Coal Database are mainly from samples collected by PSU since 1967 and are housed at the PSU Sample Bank. Additional samples that were not contained in the USGS's CoalQual Database, many of which were more recent samples taken after 1989, were obtained directly from the State Geological Surveys for Montana, Illinois, and Indiana. Whole-seam channel samples provided by PSU, Illinois, and Indiana, and both whole-seam channel and drill core samples provided by Montana, were included in the development of carbon factors.

Data on coal consumption by sector and state of origin, as well as coal production by state and rank, were obtained from EIA. EIA's *Annual Coal Report* (EIA 2001 through 2020a) is the source for state coal production by rank from 2001 through 2019. In prior years, EIA reported this data in its *Coal Industry Annual* (EIA 1990 through 2001). Data for coal consumption by state of origin and consuming sector for 2001 through 2019 was obtained from the EIA's *Annual Coal Distribution Report* (EIA 2001 through 2020b). For 1990 through 2000, end-use data was obtained from the *Coal Industry Annual* (EIA 1990 through 2001).

Uncertainty

Carbon contents vary considerably by state. Bituminous coal production and sub-bituminous coal production represented 47.2 percent and 45.0 percent of total U.S. supply in 2019, respectively. Of the states that have been producing bituminous coal since 1990, state average C content coefficients for bituminous coal vary from a low of 85.58 kg CO_2 per MMBtu in Texas to a high of 96.36 kg CO_2 per MMBtu in Arkansas. The next lowest average emission factor for bituminous coal is found in Missouri (91.71 kg CO_2 per MMBtu). In 2019, Missouri production accounted for less than 0.1 percent of overall bituminous production. More than 50 percent of bituminous coal was produced in three states in 2019: West Virginia, Kentucky, and Pennsylvania, and this share has remained fairly constant since 1990. These three states show a variation in C content for bituminous coals of ±0.7 percent, based on more than 2,000 samples (see Table A-34).

Similarly, the C content coefficients for sub-bituminous coal range from 91.29 kg CO_2 per MMBtu in Utah to 98.10 kg CO_2 per MMBtu in Alaska. However, Utah has no recorded production of sub-bituminous coal since 1990. Production of sub-bituminous coal in Alaska has made up less than 0.7 percent of total sub-bituminous production since 1990, with even this small share declining over time. Wyoming has represented between 75 percent and 90 percent of total sub-bituminous coal production in the United States throughout the time series (1990 through 2019). Thus, the C content coefficient for Wyoming (97.21 kg CO_2 per MMBtu), based on 503 samples, dominates the national average.

The interquartile range of C content coefficients among samples of sub-bituminous coal in Wyoming was ±1.5 percent from the mean. Similarly, this range among samples of bituminous coal from West Virginia, Kentucky, and Pennsylvania was ±1.2 percent or less for each state. The large number of samples and the low variability within the sample set of the states that represent the predominant source of supply of U.S. coal suggest that the uncertainty in this factor is very low, on the order of ±1.0 percent.

For comparison, J. Quick (2010) completed an analysis similar in methodology to that used here, in order to generate national average C emission factors as well as county-level factors. This study's rank-based national average factors have a maximum deviation from the factors developed in this Inventory report of 0.78 percent, which is for sub-bituminous (range: -0.32 to +0.78 percent). This corroboration further supports the assertion of minimal uncertainty in the application of the rank-based factors derived for the purposes of this Inventory.

Table A-34: Variability in Carbon Content Coefficients by Rank Across States (Kilograms CO_2 Per MMBtu)

State	Number of Samples	Bituminous	Sub-bituminous	Anthracite	Lignite
Alabama	951	92.84	-	-	99.10
Alaska	91	98.32	98.09	-	98.65
Arizona	15	93.94	97.34	-	-
Arkansas	77	96.36	-	-	94.97
Colorado	317	94.37	96.52	-	101.10
Georgia	35	95.00	-	-	-
Idaho	1	-	94.90	-	-
Illinois	460	92.53	-	-	-
Indiana	745	92.30	-	-	-
Iowa	100	91.87	-	-	-
Kansas	29	90.91	-	-	-
Kentucky	897	92.61	-	-	-
Louisiana	1	-	-	-	96.01
Maryland	47	94.29	-	-	-
Massachusetts	3	-	-	114.82	-
Michigan	3	-	-	-	92.87
Mississippi	8	-	-	-	98.18
Missouri	111	91.71	-	-	-
Montana	908	96.01	96.61	-	98.34
Nebraska	6	103.59	-	-	-
Nevada	2	94.41	-	-	99.86
New Mexico	185	94.28	94.88	103.92	-
North Dakota	202	-	93.97	-	99.47
Ohio	674	91.84	-	-	-
Oklahoma	63	92.33	-	-	-
Pennsylvania	849	93.33	-	103.68	-
Tennessee	61	92.81	-	-	-
Texas	64	85.58	94.19	-	94.46
Utah	169	95.75	91.29	-	-
Virginia	465	93.51	-	98.54	-
Washington	18	94.53	97.35	102.53	106.55
West Virginia	612	93.84	-	-	-
Wyoming	503	94.80	97.21	-	-
U.S. Average	**8,672**	**93.46**	**96.01**	**102.15**	**98.95**

Note: "-" Indicates no sample data available. Average is weighted by number of samples.
Sources: Calculated from USGS (1998) and PSU (2010), Gunderson (2019), IGS (2019), and ISGS (2019).

Natural Gas

Natural gas is predominantly composed of methane (CH_4), which is 75 percent C by weight and contains 14.2 MMT C/QBtu (higher heating value), but it may also contain many other compounds that can lower or raise its overall C content. These other compounds may be divided into two classes: (1) natural gas liquids (NGLs) and (2) non-hydrocarbon gases. The most common NGLs are ethane (C_2H_6), propane (C_3H_8), butane (C_4H_{10}), and, to a lesser extent, pentane (C_5H_{12}) and hexane (C_6H_{14}). Because the NGLs have more C atoms than CH_4 (which has only one), their presence increases the overall C content of natural gas. NGLs have a commercial value greater than that of CH_4, and therefore are usually separated from raw natural gas at gas processing plants and sold as separate products. Ethane is typically used as a petrochemical feedstock, propane and butane have diverse uses, and natural gasoline[15] contributes to the gasoline/naphtha "octane pool," used primarily to make motor gasoline.

Raw natural gas can also contain varying amounts of non-hydrocarbon gases, such as CO_2, nitrogen, helium and other noble gases, and hydrogen sulfide. The share of non-hydrocarbon gases is usually less than 5 percent of the total, but there are individual natural gas reservoirs where the share can be much larger. The treatment of non-hydrocarbon gases in raw gas varies. Hydrogen sulfide is always removed. Inert gases are removed if their presence is substantial enough to reduce the energy content of the gas below pipeline specifications (see Step 1, below). Otherwise, inert gases will usually be left in the natural gas. Because the raw gas that is usually flared (see Step 2, below) contains NGLs and CO_2, it will typically have a higher overall C content than gas that has been processed and moved to end-use customers via transmission and distribution pipelines.

Methodology

The methodology for estimating the C contents of pipeline and flared natural gas can be described in five steps.

Step 1: Define pipeline-quality natural gas

In the United States, pipeline-quality natural gas is required to have an energy content greater than 970 Btu per cubic foot, but less than 1,100 Btu per cubic foot. Hydrogen sulfide content must be negligible. Typical pipeline-quality natural gas is about 95 percent CH_4, 3 percent NGLs, and 2 percent non-hydrocarbon gases, of which approximately half is CO_2.

However, there remains a range of gas compositions that are consistent with pipeline specifications. The minimum C content coefficient for natural gas would match that for pure CH_4, which equates to an energy content of 1,005 Btu per standard cubic foot. Gas compositions with higher or lower Btu content tend to have higher C emission factors, because the "low" Btu gas has a higher content of inert gases (including CO_2 offset with more NGLs), while "high" Btu gas tends to have more NGLs.

Step 2: Define flared gas

Every year, a certain amount of natural gas is flared in the United States. There are several reasons that gas is flared:

- There may be no market for some batches of natural gas, the amount may be too small or too variable, or the quality might be too poor to justify treating the gas and transporting it to market (such is the case when gas contains large shares of CO_2). Most natural gas that is flared for these reasons is "rich" associated gas, with relatively high energy content, high NGL content, and a high C content.
- Gas treatment plants may flare substantial volumes of natural gas because of "process upsets," because the gas is "off spec," or possibly as part of an emissions control system. Gas flared at processing plants may be of variable quality.

Data on the energy content of flare gas, as reported by states to EIA, indicate an average energy content of 1,130 Btu per standard cubic foot (EIA 1994). Flare gas may have an even higher energy content than reported by EIA since rich associated gas can have energy contents as high as 1,300 to 1,400 Btu per cubic foot.

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[15] A term used in the gas processing industry to refer to a mixture of liquid hydrocarbons (mostly pentanes and heavier hydrocarbons) extracted from natural gas.

Step 3: Determine a relationship between carbon content and heat content

A relationship between C content and heat content may be used to develop a C content coefficient for natural gas consumed in the United States. In 1994, EIA examined the composition (including C contents) of 6,743 samples of pipeline-quality natural gas from utilities and/or pipeline companies in 26 cities located in 19 states. To demonstrate that these samples were representative of actual natural gas "as consumed" in the United States, their heat content was compared to that of the national average. For the most recent year, the average heat content of natural gas consumed in the United States was -1,036 Btu per cubic foot, and has varied by less than 1 percent (1,025 to 1,037 Btu per cubic foot) over the past 10 years. Meanwhile, the average heat content of the 6,743 samples was 1,027 Btu per cubic foot, and the median heat content was 1,031 Btu per cubic foot. Thus, the average heat content of the sample set falls well within the typical range of natural gas consumed in the United States, suggesting that these samples continue to be representative of natural gas "as consumed" in the United States. The average and median composition of these samples appear in Table A-35.

Table A-35: Composition of Natural Gas (Percent)

Compound	Average	Median
Methane	93.07	95.00
Ethane	3.21	2.79
Propane	0.59	0.48
Higher Hydrocarbons	0.32	0.30
Non-hydrocarbons	2.81	1.43
Higher Heating Value (Btu per cubic foot)	1,027	1,031

Source: Gas Technology Institute (1992).

Carbon contents were calculated for a series of sub-samples based on their CO_2 content and heat content. Carbon contents were calculated for the groups of samples with less than 1.0 percent (n=5,181) and less than 1.5 percent CO_2 only (n=6,522) and those with less than 1.0 or 1.5 percent CO_2 and less than 1,050 Btu/cf (n=4,888 and 6,166, respectively). These stratifications were chosen to exclude samples with CO_2 content and heat contents outside the range of pipeline-quality natural gas. In addition, hexane was removed from the samples since it is usually stripped out of raw natural gas before delivery because it is a valuable natural gas liquid used as a feedstock for gasoline. The average carbon contents for the four separate sub-samples are shown below in Table A-36.

Table A-36: Carbon Content of Pipeline-Quality Natural Gas by CO_2 and Heat Content (MMT C/QBtu)

Sample	Average Carbon Content
Full Sample	14.48
< 1.0% CO_2	14.43
< 1.5% CO_2	14.47
< 1.0 % CO_2 and <1,050 Btu/cf	14.42
< 1.5 % CO_2 and <1,050 Btu/cf	14.47

Source: EPA (2010).

Step 4. Apply carbon content coefficients developed in Step 3 to pipeline natural gas

A regression analysis was performed on the sub-samples in to further examine the relationship between carbon (C) content and heat content (both on a per cubic foot basis). The regression used carbon content as the dependent variable and heat content as the independent variable. The resulting R-squared values[16] for each of the sub-samples ranged from 0.79 for samples with less than 1.5 percent CO_2 and under 1,050 Btu/cf to 0.91 for samples containing less than 1.0 percent CO_2 only. However, the sub-sample with less than 1.5 percent CO_2 and 1,050 Btu/cf was chosen as the representative sample for two reasons. First, it most accurately reflects the range of CO_2 content and heat content of pipeline quality natural gas. Secondly, the R-squared value, although it is the lowest of the sub-groups tested, remains

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[16] R-squared represents the percentage of variation in the dependent variable (in this case carbon content) explained by variation in the independent variables.

relatively high. This high R-squared indicates a low percentage of variation in C content as related to heat content. The regression for this sub-sample resulted in the following equation:

$$\text{C Content} = (0.011 \times \text{Heat Content}) + 3.5341$$

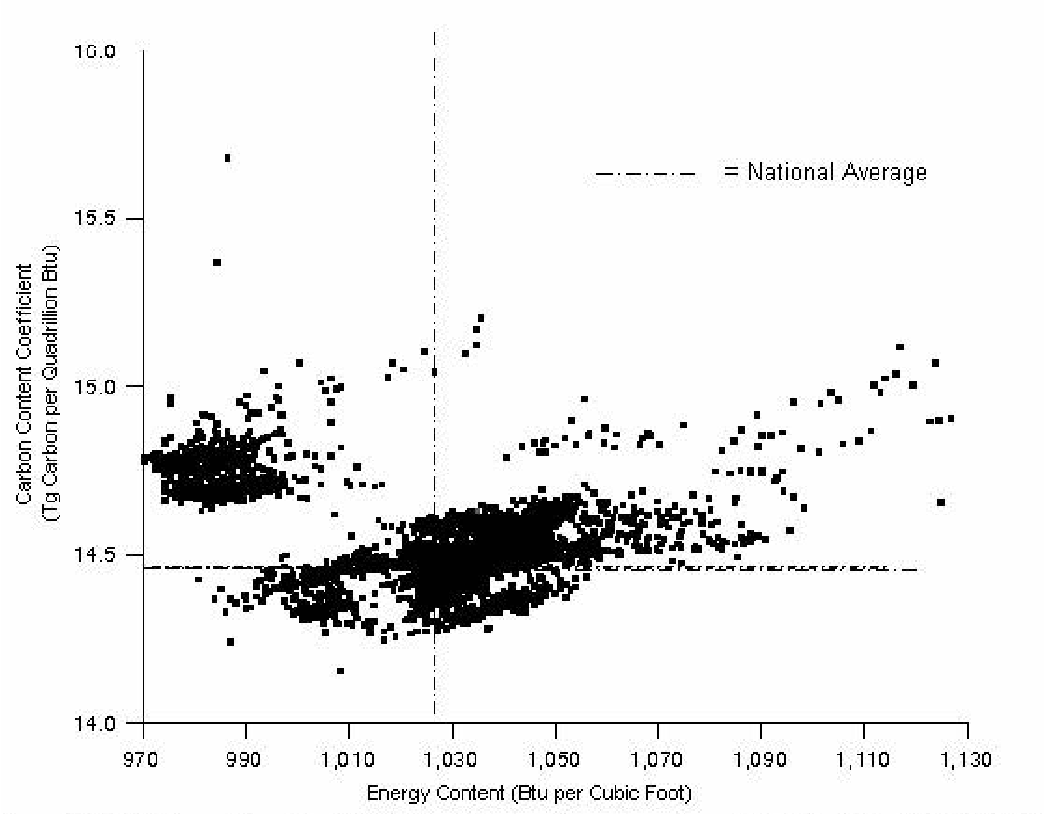
This equation was used to estimate the annual predicted carbon content of natural gas from 1990 to 2019 based on the EIA's national average pipeline-quality gas heat content for each year (EIA 2020a). The table of average C contents for each year is shown below in Table A-37.

Table A-37: Carbon Content Coefficients for Natural Gas (MMT Carbon/QBtu)

Fuel Type	1990	1995	2000	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Natural Gas	14.46	14.47	14.47	14.48	14.48	14.47	14.46	14.45	14.43	14.43	14.43	14.43	14.43

Source: Calculated from EPA (2010) and EIA (2020a).

Figure A-1: Carbon Content for Samples of Pipeline-Quality Natural Gas Included in the Gas Technology Institute Database



Source: EIA (1994) Energy Information Administration, Emissions of Greenhouse Gases in the United States 1987-1992, U.S. Department of Energy, Washington, DC, November, 1994, DOE/EIA 0573, Appendix A.

Natural gas suppliers may achieve the same overall energy content from a wide variety of methane, higher hydrocarbon, and non-hydrocarbon gas combinations. Thus, the plot reveals large variations in C content for a single Btu value. In fact, the variation in C content for a single Btu value may be nearly as great as the variation for the whole sample. As a result, while energy content has some predictive value, the specific energy content does not substantially improve the accuracy of an estimated C content coefficient beyond the ±5.0 percent offered with the knowledge that it is of pipeline-quality.

The plot of C content also reveals other interesting anomalies. Samples with the lowest emissions coefficients tend to have energy contents of about 1,000 Btu per cubic foot. They are composed of almost pure CH_4. Samples with a greater proportion of NGLs (e.g., ethane, propane, and butane) tend to have energy contents greater than 1,000 Btu per cubic foot, along with higher emissions coefficients. Samples with a greater proportion of inert gases tend to have lower energy content, but they usually contain CO_2 as one of the inert gases and, consequently, also tend to have higher emission coefficients (see left side of Figure A-1).

For the full sample (n=6,743), the average C content of a cubic foot of gas was 14.48 MMT C/QBtu. Additionally, a regression analysis using the full sample produced a predicted C content of 14.49 MMT C/QBtu based on a heat content of 1,029 Btu/cf (the average heat content in the United States for the most recent year). However, these two values include an upward influence on the resulting carbon content that is caused by inclusion in the sample set of the samples that contain large amounts of inert carbon dioxide and those samples with more than 1,050 Btu per cubic foot that contain an unusually large amount of NGLs. Because typical gas consumed in the United States does not contain such a large amount of carbon dioxide or natural gas liquids, a C content of 14.43 MMT C/QBtu (see Table A-37), based on samples with less than 1.5 percent carbon dioxide and less than 1,050 Btu per cubic foot, better represents the pipeline-quality fuels typically consumed.

Furthermore, research was done on CO_2 emission factors for fuel gas used by upstream oil and gas producers in order to determine whether a different CO_2 emission factor for fuel gas used in offshore oil and gas production than the emission factor for the processed gas that enters the transmission, storage and distribution networks used in power and industrial plants and by other users is warranted. It was determined that a different factor was not warranted as natural gas carbon content is based on the heating value of the gas and EIA reports that the heat content of dry natural gas produced (which is used in upstream oil and gas production) is the same value as natural gas consumed in downstream operations (EIA 2020a). Therefore, the same carbon factor is used for all natural gas consumption including upstream operations.

Petroleum

There are four critical determinants of the C content coefficient for a petroleum-based fuel:

- The density of the fuel (e.g., the weight in kilograms of one barrel of fuel);
- The fraction by mass of the product that consists of hydrocarbons, and the fraction of non-hydrocarbon impurities;
- The specific types of “families” of hydrocarbons that make up the hydrocarbon portion of the fuel; and
- The heat content of the fuel.

$$C_{fuel} = (D_{fuel} \times S_{fuel}) / E_{fuel}$$

where,

C_{fuel} = The C content coefficient of the fuel
D_{fuel} = The density of the fuel
S_{fuel} = The share of the fuel that is C
E_{fuel} = The heat content of the fuel

Most of the density, carbon share, or heat contents applied to calculate the carbon coefficients for petroleum products that are described in this sub-Annex and applied to this emissions Inventory were updated in 2010 for the 1990 through 2008 Inventory report. These changes have been made where necessary to increase the accuracy of the underlying data or to align the petroleum properties data used in this report with that developed for use in EPA’s *Mandatory Reporting of Greenhouse Gases Rule* (EPA 2009b).

Petroleum products vary between 5.6 degrees API gravity[17] (dense products such as asphalt and road oil) and 247 degrees (ethane). This is a range in density of 60 to 150 kilograms per barrel, or ±50 percent. The variation in C content, however, is much smaller (±5 to 7 percent) for products produced by standard distillation refining: ethane is 80

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[17] API gravity is an arbitrary scale expressing the gravity or density of liquid petroleum products, as established by the American Petroleum Institute (API). The measuring scale is calibrated in terms of degrees API. The higher the API gravity, the lighter the compound. Light crude oils generally exceed 38 degrees API and heavy crude oils are all crude oils with an API gravity of 22 degrees or below. Intermediate crude oils fall in the range of 22 degrees to 38 degrees API gravity. API gravity can be calculated with the following formula: API Gravity = (141.5/Specific Gravity) – 131.5. Specific gravity is the density of a material relative to that of water. At standard temperature and pressure, there are 62.36 pounds of water per cubic foot, or 8.337 pounds water per gallon.

percent C by weight, while petroleum coke is 90 to 92 percent C. This tightly bound range of C contents can be explained by basic petroleum chemistry (see below). Additional refining can increase carbon contents. Calcined coke, for example, is formed by heat treating petroleum coke to about 1600 degrees Kelvin (calcining), to expel volatile materials and increase the percentage of elemental C. This product can contain as much as 97 to 99 percent carbon. Calcined coke is mainly used in the aluminum and steel industry to produce C anodes.

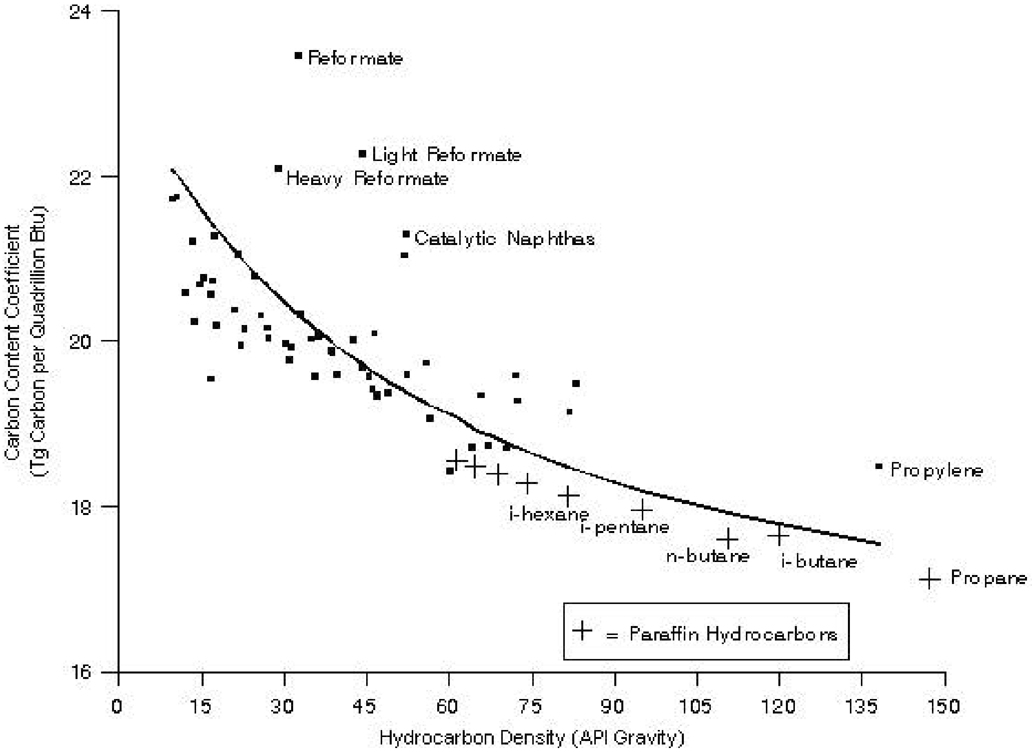
Petroleum Chemistry

Crude oil and petroleum products are typically mixtures of several hundred distinct compounds, predominantly hydrocarbons. All hydrocarbons contain hydrogen and C in various proportions. When crude oil is distilled into petroleum products, it is sorted into fractions by the boiling temperature of these hundreds of organic compounds. Boiling temperature is strongly correlated with the number of C atoms in each molecule. Petroleum products consisting of relatively simple molecules and few C atoms have low boiling temperatures, while larger molecules with more C atoms have higher boiling temperatures.

Products that boil off at higher temperatures are usually denser, which implies greater C content as well. Petroleum products with higher C contents, in general, have lower energy content per unit mass and higher energy content per unit volume than products with lower C contents. Empirical research led to the establishment of a set of quantitative relationships between density, energy content per unit weight and volume, and C and hydrogen content.

Figure A-2 compares C content coefficients calculated on the basis of the derived formula with actual C content coefficients for a range of crude oils, fuel oils, petroleum products, and pure hydrocarbons. The actual fuel samples were drawn from the sources described below in the discussions of individual petroleum products.

Figure A-2: Estimated and Actual Relationships Between Petroleum Carbon Content Coefficients and Hydrocarbon Density



Source: Carbon content factors for paraffins are calculated based on the properties of hydrocarbons in V. Guthrie (ed.), *Petroleum Products Handbook* (New York: McGraw Hill, 1960) p. 33. Carbon content factors from other petroleum products are drawn from sources described below. Relationship between density and emission factors based on the relationship between density and energy content in U.S. Department of Commerce, National Bureau of Standards, *Thermal Properties of Petroleum Products*, Miscellaneous Publication, No. 97 (Washington, D.C., 1929), pp.16-21, and relationship between energy content and fuel composition in S. Ringen, J. Lanum, and F.P. Miknis, "Calculating Heating Values from the Elemental Composition of Fossil Fuels,' *Fuel*, Vol. 58 (January 1979), p.69.

The derived empirical relationship between C content per unit heat and density is based on the types of hydrocarbons most frequently encountered. Petroleum fuels can vary from this relationship due to non-hydrocarbon impurities and variations in molecular structure among classes of hydrocarbons. In the absence of more exact information, this empirical relationship offers a good indication of C content.

Non-hydrocarbon Impurities

Most fuels contain a certain share of non-hydrocarbon material. This is also primarily true of crude oils and fuel oils. The most common impurity is sulfur, which typically accounts for between 0.5 and 4 percent of the mass of most crude oils, and can form an even higher percentage of heavy fuel oils. Some crude oils and fuel oils also contain appreciable quantities of oxygen and nitrogen, typically in the form of asphaltenes or various acids. The nitrogen and oxygen content of crude oils can range from near zero to a few percent by weight. Lighter petroleum products have much lower levels of impurities, because the refining process tends to concentrate all of the non-hydrocarbons in the residual oil fraction. Light products usually contain less than 0.5 percent non-hydrocarbons by mass. Thus, the C content of heavy fuel oils can often be several percent lower than that of lighter fuels, due entirely to the presence of non-hydrocarbons.

Variations in Hydrocarbon Classes

Hydrocarbons can be divided into five general categories, each with a distinctive relationship between density and C content and physical properties. Refiners tend to control the mix of hydrocarbon types in particular products in order to give petroleum products distinct properties. The main classes of hydrocarbons are described below.

Paraffins. Paraffins are the most common constituent of crude oil, usually comprising 60 percent by mass. Paraffins are straight-chain hydrocarbons with the general formula C_nH_{2n+2}. Paraffins include ethane (C_2H_6), propane (C_3H_8), butane (C_4H_{10}), and octane (C_8H_{18}). As the chemical formula suggests, the C content of the paraffins increases with their C number: ethane is 79.89 percent C by weight, octane 84.12 percent. As the size of paraffin molecules increases, the C content approaches the limiting value of 85.7 percent asymptotical (see Figure A-3).

Cycloparaffins. Cycloparaffins are similar to paraffins, except that the C molecules form ring structures rather than straight chains, and consequently require two fewer hydrogen molecules than paraffins. Cycloparaffins always have the general formula C_nH_{2n} and are 85.63 percent C by mass, regardless of molecular size.

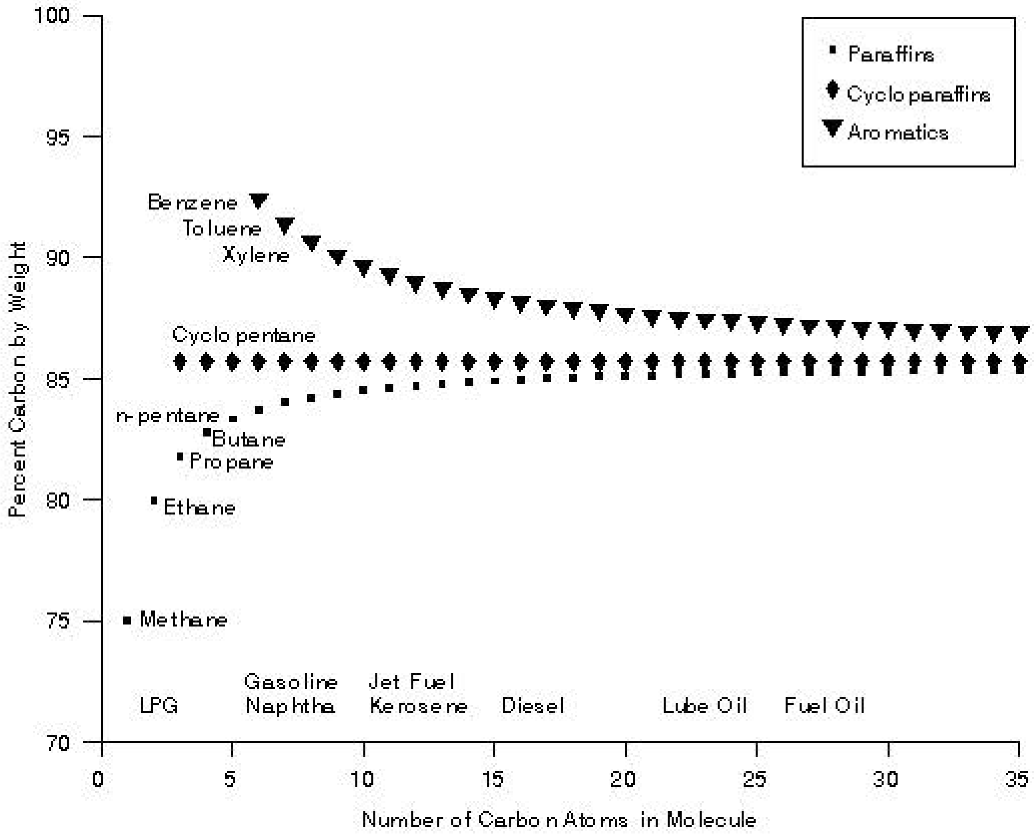
Olefins. Olefins are a very reactive and unstable form of paraffin: a straight chain with two carbon atoms double bonded together (thus are unsaturated) compared to the carbon atoms in a paraffin (which are saturated with hydrogen). They are never found in crude oil but are created in moderate quantities by the refining process. Gasoline, for example, may contain between 2 and 20 percent olefins. They also have the general formula C_nH_{2n}, and hence are also always 85.63 percent C by weight. Propylene (C_3H_6), a common intermediate petrochemical product, is an olefin.

Aromatics. Aromatics are very reactive hydrocarbons that are relatively uncommon in crude oil (10 percent or less). Light aromatics increase the octane level in gasoline, and consequently are deliberately created by catalytic reforming of heavy naphtha. Aromatics also take the form of ring structures with some double bonds between C atoms. The most common aromatics are benzene (C_6H_6), toluene (C_7H_8), and xylene (C_8H_{10}). The general formula for aromatics is C_nH_{2n-6}. Benzene is 92.26 percent C by mass, while xylene is 90.51 percent C by mass and toluene is 91.25 percent C by mass. Unlike the other hydrocarbon families, the C content of aromatics declines asymptotically toward 85.7 percent with increasing C number and density (see Figure A-3).

Polynuclear Aromatics. Polynuclear aromatics are large molecules with a multiple ring structure and few hydrogen atoms, such as naphthalene ($C_{10}H_8$ and 93.71 percent C by mass) and anthracene ($C_{14}H_{10}$ and 97.7 percent C). They are relatively rare but do appear in heavier petroleum products.

Figure A-3 illustrates the share of C by weight for each class of hydrocarbon. Hydrocarbon molecules containing 2 to 4 C atoms are all natural gas liquids; hydrocarbons with 5 to 10 C atoms are predominantly found in naphtha and gasoline; and hydrocarbon compounds with 12 to 20 C atoms comprise "middle distillates," which are used to make diesel fuel, kerosene and jet fuel. Larger molecules which can be vacuum distilled may be used as lubricants, waxes, and residual fuel oil or cracked and blended into the gasoline or distillate pools.

Figure A-3: Carbon Content of Pure Hydrocarbons as a Function of Carbon Number



Source: J.M. Hunt, *Petroleum Geochemistry and Geology* (San Francisco, CA, W.H. Freeman and Company, 1979), pp. 31-37.

If nothing is known about the composition of a particular petroleum product, assuming that it is 85.7 percent C by mass is not an unreasonable first approximation. Since denser products have higher C numbers, this guess would be most likely to be correct for crude oils and fuel oils. The C content of lighter products is more affected by the shares of paraffins and aromatics in the blend.

Energy Content of Petroleum Products

The exact energy content (gross heat of combustion) of petroleum products is not generally known. EIA estimates energy consumption in Btu on the basis of a set of industry-standard conversion factors. These conversion factors are generally accurate to within 3 to 5 percent.

Individual Petroleum Products

The United States maintains data on the consumption of more than twenty separate petroleum products and product categories. The C contents, heat contents, and density for each product are provided below in Table A-38. A description of the methods and data sources for estimating the key parameters for each individual petroleum product appears below.

Table A-38: Carbon Content Coefficients and Underlying Data for Petroleum Products

Fuel	Carbon Content (MMT C/QBtu)	Gross Heat of Combustion (MMBtu/Barrel)	Density (API Gravity)	Percent Carbon
Motor Gasoline	19.27	(See a)	(See a)	(See a)
LPG (Propane)	17.15	3.841	155.3	81.80
HGL (Energy Use)[b]	17.47	(See b)	(See b)	(See b)
HGL (Non-Energy Use)[b]	16.85	(See b)	(See b)	(See b)
Jet Fuel	19.70	5.670	42.0	86.30
Distillate Fuel No. 1	19.98	5.822	35.3	86.40
Distillate Fuel No. 2	20.22	(See c)	(See c)	(See c)
Distillate Fuel No. 4	20.47	6.135	23.2	86.47
Residual Fuel No. 5	19.89	5.879	33.0	85.67
Residual Fuel No. 6	20.48	6.287	15.5	84.67
Asphalt and Road Oil	20.55	6.636	5.6	83.47
Lubricants	20.20	6.065	25.7	85.80
Naphtha (< 400 deg. F)[c]	18.55	5.248	62.4	84.11
Other Oil (>400 deg. F)[c]	20.17	5.825	35.8	87.30
Aviation Gasoline	18.86	5.048	69.0	85.00
Kerosene	19.96	5.670	35.3	86.40
Petroleum Coke	27.85	6.024	-	92.28
Special Naphtha	19.74	5.248	52.0	84.75
Petroleum Waxes	19.80	5.537	43.3	85.30
Still Gas	18.20	6.000	-	77.70
Crude Oil	20.31	5.800	31.2	85.49
Unfinished Oils	20.31	5.825	31.2	85.49
Miscellaneous Products	0.00	5.796	31.2	0.00
Pentanes Plus	18.24	4.638	81.3	83.70

Note: “-“ Indicates no sample data available. For carbon content coefficients that are annually variable, 2019 values are shown.

[a] Calculation of the carbon content coefficient for motor gasoline in 2008 uses separate higher heating values for conventional and reformulated gasoline of 5.253 and 5.150, respectively (EIA 2008a). Densities and carbon shares (percent carbon) are annually variable and separated by both fuel formulation and grade, see Motor Gasoline and Blending Components, below, for details.

[b] HGL is a blend of multiple paraffinic hydrocarbons: ethane, propane, isobutane, and normal butane, and their associated olefins: ethylene, propylene, isobutylene, and butylene, each with their own heat content, density, and C content, see Table A-40.

[c] Petrochemical feedstocks have been split into naphthas and other oils for this Inventory report. Parameters presented are for naphthas with a boiling temperature less than 400 degrees Fahrenheit. Other oils are petrochemical feedstocks with higher boiling points. They are assumed to have the same characteristics as distillate fuel oil no. 2.

Sources: EIA (1994); EIA (2009a); EPA (2020b); and EPA (2010).

Motor Gasoline and Motor Gasoline Blending Components

Motor gasoline is a complex mixture of relatively volatile hydrocarbons with or without small quantities of additives, blended to form a fuel suitable for use in spark-ignition engines.[18] “Motor Gasoline” includes conventional gasoline; all types of oxygenated gasoline, including gasohol; and reformulated gasoline; but excludes aviation gasoline.

Gasoline is the most widely used petroleum product in the United States, and its combustion accounts for nearly 22 percent of all U.S. CO_2 emissions. EIA collects consumption data (i.e., “petroleum products supplied” to end-users) for several types of finished gasoline over the 1990 through 2019 time period: regular, mid-grade, and premium

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[18] Motor gasoline, as defined in ASTM Specification D 4814 or Federal Specification VV-G-1690C, is characterized as having a boiling range of 122 degrees to 158 degrees Fahrenheit at the 10-percent recovery point to 365 degrees to 374 degrees Fahrenheit at the 90-percent recovery point.

conventional gasoline (all years) and regular, mid-grade, and premium reformulated gasoline (November 1994 to 2019). Leaded and oxygenated gasoline are not separately included in the data used for this report.[19]

The American Society for Testing and Materials (ASTM) standards permit a broad range of densities for gasoline, ranging from 50 to 70 degrees API gravity, or 111.52 to 112.65 kilograms per barrel (EIA 1994), which implies a range of possible C and energy contents per barrel. The density of motor gasoline across grades and formulations for 1990-2008 is taken from the National Institute of Petroleum and Energy Research. Values from 2008 have been used as a proxy for 2009 through 2019.

The density of motor gasoline increased across all grades through 1994, partly as a result of the leaded gasoline phase-out. In order to maintain the “anti-knock” quality and octane ratings of gasoline in the absence of lead, the portion of aromatic hydrocarbons blended into gasoline through the refining process was increased. As discussed above, aromatic hydrocarbons have a lower ratio of hydrogen to C than other hydrocarbons typically found in gasoline, and therefore increase fuel density.

The trend in gasoline density was reversed beginning in 1996 with the development of fuel additives that raised oxygen content. In 1995, a requirement for reformulated gasoline in non-attainment areas implemented under the Clean Air Act Amendments further changed the composition of gasoline consumed in the United States. Through 2005, methyl tertiary butyl ether (MTBE), ethanol, ethyl tertiary butyl ether (ETBE), and tertiary amyl methyl ether (TAME) were added to reformulated and sometimes to conventional gasoline to boost its oxygen content, reduce its toxics impacts and increase its octane. The increased oxygen reduced the emissions of carbon monoxide and unburned hydrocarbons. These oxygen-rich blending components are also much lower in C than standard gasoline. The average gallon of reformulated gasoline consumed in 2005 contained over 10 percent MTBE and 0.6 percent TAME (by volume). The characteristics of reformulated fuel additives appear in Table A-39.

Table A-39: Characteristics of Major Reformulated Fuel Additives

Additive	Density (Degrees API)	Carbon Share (Percent)
MTBE	58.6	68.13
ETBE	58.5	70.53
TAME	51.2	70.53
DIPE	62.7	70.53
Ethanol (100%)	45.8	52.14

Source: EPA (2009b).

Since 2005, due to concerns about the potential environmental consequences of the use of MTBE in fuels, there has been a shift away from the addition of MTBE, TAME, ETBE, and DIPE and towards the use of ethanol as a fuel oxygenate.[20] Ethanol, also called ethyl alcohol, is an anhydrous alcohol with molecular formula C_2H_5OH. Ethanol has a lower C share than other oxygenates, approximately 52 percent compared to about 70 percent for MTBE and TAME. The density of ethanol was calculated by fitting density data at 10-degree intervals to a polynomial of order two and then using the fit to interpolate the value of the density at 15 degrees Celsius. A common fuel mixture of 10 percent denatured ethanol (denatured by 2 percent hydrocarbons) and 90 percent gasoline, known as E10, is widely used in the United States and does not require any modification to vehicle engines or fuel systems. The federal Renewable Fuel Standard (RFS) program requires a certain volume of renewable fuel, including ethanol, be blended into the national fuel supply.[21] Ethanol blends up to E85 (85 percent ethanol, 15 percent gasoline) are in use in the United States but can only be used in specially designed vehicles called flexible fuel vehicles (FFVs). Most ethanol fuel in the United States is produced using corn as feedstock,[22] although production pathways utilizing agricultural waste, woody biomass and other resources are in development.

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[19] Oxygenated gasoline volumes are included in the conventional gasoline data provided by EIA from 2007 onwards. Leaded gasoline was included in total gasoline by EIA until October 1993.

[20] The annual motor gasoline carbon contents that are applied for this Inventory do not include the carbon contributed by the ethanol contained in reformulated fuels. Ethanol is a biofuel, and net carbon fluxes from changes in biogenic carbon reservoirs in croplands are accounted for in the estimates for Land Use, Land-Use Change and Forestry.

[21] See <https://www.epa.gov/renewable-fuel-standard-program>.

[22] See <https://www.epa.gov/fuels-registration-reporting-and-compliance-help/public-data-renewable-fuel-standard>.

Methodology for Years 1990-1999:

Step 1. Disaggregate U.S. gasoline consumption by grade and type

Separate monthly data for U.S. sales to end users of finished gasoline by product grade and season for both standard gasoline and reformulated gasoline were obtained from the EIA.

Step 2. Develop carbon content coefficients for each grade and type

Annual C content coefficients for each gasoline grade, type, and season are derived from four parameters for each constituent of the finished gasoline blend: the volumetric share of each constituent,[23] the density of the constituent, share of the constituent[24] that is C; and the energy content of a gallon of the relevant formulation of gasoline. The percent by mass of each constituent of each gasoline type was calculated using percent by volume data from the National Institute for Petroleum and Energy Research (NIPER) and the density of each constituent.

The ether additives listed in Table A-39 are accounted for in both reformulated fuels and conventional fuels, to the extent that they were present in the fuel. From 2006 onward, reformulated fuel mass percentages are calculated from their constituents, net of the share provided by ethanol. C content coefficients were then derived from the calculated percent by mass values by weighting the C share of each constituent by its contribution to the total mass of the finished motor gasoline product.

Step 3. Weight overall gasoline carbon content coefficient for consumption of each grade and type

The C content for each grade, type, and season of fuel is multiplied by the share of annual consumption represented by the grade and fuel type during the relevant time period. Individual coefficients are then summed and totaled to yield an overall C content coefficient for each year.

Methodology for Years 2000-Present:

Step 1. Disaggregate U.S. gasoline consumption by grade and type

Separate monthly data for U.S. sales to end users of finished gasoline by product grade and season for both standard gasoline and reformulated gasoline were obtained from the EIA. The EIA publishes prime supplier sales volumes of motor gasoline by type (conventional, oxygenated, and reformulated) and by grade (regular, midgrade and premium) for each month from 1983 to present (EIA 2020c). Gasoline sold in May through August was assumed to be summer grade, gasoline sold in September was assumed to be half summer and half winter grade, and gasoline sold in other months was assumed to be winter grade.

Step 2. Develop carbon content coefficients for each grade and type

Fuel properties are gathered through the Alliance of North American Fuel Survey (NAFS) published by the Alliance of Automobile Manufacturers (AAM), an association which is now part of the Alliance for Automotive Innovation. This fuel survey is conducted twice per year, in January and July, and includes measured properties of both regular and premium gasoline. While the exact number of samples vary by year and location, fuel samples are drawn from multiple retail locations in each of over 20 U.S. cities for each biannual survey.

The carbon content and net heating value are calculated according to ASTM D3343, Standard Test Method for the Estimation of Hydrogen Content of Aviation Fuels, and ASTM D3338, Standard Test Method for the Net Heat of Combustion of Aviation Fuels, respectively using fuel properties inputs from the NAFS for each year and season. These methods use a correlation between the measured fuel distillation range, API gravity, and aromatic content to estimate the hydrogen content and net heating values. The C content of hydrocarbon fuel calculated according to ASTM D3343 applies to hydrocarbon containing fuels only and is not applicable towards oxygenated fuel blends. However, recently EPA has proposed an amendment to 40 CFR §600.113-12, containing equations allowing for the estimation of base fuel blendstock properties using the bulk oxygenated fuel properties. This technique is applied here for oxygenated gasoline calculations.

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[23] Calculations account for the properties of the individual constituents of gasoline, including, as applicable to the fuel grade and type: aromatics (excluding benzene), olefins, benzene, saturates, MTBE, TAME, ETBE, DIPE and ethanol.

[24] Saturates are assumed to be octane and aromatics are assumed to be toluene.

The fuels sampled in the NAFS by AAM are assumed to be representative of the seasonal fuels sold throughout the U.S. Also, the method of calculation of the fuel properties of the hydrocarbon fraction of the fuel from blended fuel properties was developed for Tier 3 certification test fuels, and not commercial fuel blends as used here.

Data Sources

Data for the density of motor gasoline were derived from NIPER (1990 through 2009). Data on the characteristics of reformulated gasoline, including C share, were also taken from NIPER (1990 through 2009) and Alliance of North American Fuel Survey (NAFS) published by the Alliance of Automobile Manufacturers (AAM), an association which is now part of the Alliance for Automotive Innovation.

Standard heat contents for motor gasoline of 5.222 MMBtu per barrel conventional gasoline and 5.150 MMBtu per barrel reformulated gasoline[25] were adopted from EIA (2009a).

Uncertainty

The uncertainty underlying the C content coefficients for motor gasoline has three underlying sources: (1) the uncertainty in the averages published by NIPER, (2) uncertainty in the C shares assumed in the EPA's analysis to be representative of the constituent hydrocarbon classes within gasoline (aromatics, olefins and saturates), and (3) uncertainty in the heat contents applied.

A variable number of samples are used each year to determine the average percent by volume share of each hydrocarbon within each grade, season and formulation of gasoline that were obtained from NIPER through 2009. The total number of samples analyzed for each seasonal NIPER report varies from approximately 730 to over 1,800 samples over the period from 1990 through 2009. The number of samples analyzed that underlie the calculation of the average make-up of each seasonal formulation and grade varies from approximately 50 to over 400, with the greatest number of samples each season being of conventional, regular or premium gasoline. Further, not all sample data submitted to NIPER contains data for each of the properties, such that the number of samples underlying each constituent average value for each season, grade and formulation may be variable within the single gasoline type (e.g., of the 1,073 samples for which some data was obtained for gasoline sold in Winter 1995 through 1996, benzene content was provided for all samples, while olefin, aromatic and saturate content was provided for just 736 of those samples).

The distribution of sample origin collected for the NIPER report and the calculation of national averages are not reflective of sales volumes. The publication of simple, rather than sales-weighted averages to represent national average values increases the uncertainty in their application to the calculation of carbon content factors for the purposes of this Inventory. Further, data for each sample is submitted voluntarily, which may also affect their representativeness.

Additionally, because the simple average constituent shares are calculated based upon data that have been renormalized to account for the share of ethers and alcohols, total average volume shares may not equal 100 percent.

The simple average for each hydrocarbon constituent is contained within a range of values that are as wide as -63.0/+74.5 percent of the mean across the Winter 2007 through 2008 and -51.3/+49.6 percent across the Summer 2008 samples of conventional, regular grade gasoline. However, these wide ranges exist for benzene, which generally accounts for only 1 percent, by volume, of each gallon. In contrast, saturates, the class of hydrocarbon that contribute the largest share, by volume, ranges only -6.5/+6.4 percent for the same set of winter samples and -8.8/+15.7 percent for the summer samples.

Secondly, EPA's calculation of C content factors for each gasoline type includes the following assumptions: for the purposes of assigning a carbon share to each compound in the blend, aromatic content (other than benzene) is assumed to be toluene and saturated hydrocarbons are assumed to be octane. All olefins have the same carbon share because they all have a molecular formula in the form C_nH_{2n}, so the C share applied to the olefin portion of the total gasoline blend does not increase the level of uncertainty in the calculation. These assumptions are based upon the use of octane and octane isomers as the primary saturates and toluene as the primary non-benzene aromatic in U.S. motor gasoline blends. The octane rating of a particular blend is based upon the equivalent iso-octane to heptane ratio, which is achieved through significant octane content relative to the other saturates. Aside from benzene, U.S. gasolines will include toluene as a major aromatic component, so toluene may be assumed a reasonable representative of total non-benzene aromatic content (EPA 2009a).

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[25] The reformulated gasoline heat content is applied to both reformulated blends containing ethers and those containing ethanol.

For each hydrocarbon category, the assumed C content lies within a range of possible values for all such hydrocarbons. Among saturated hydrocarbons, the C share of octane (84.12 percent) is at the high end of the range while ethane represents the low end of the range (79.89 percent C). Total saturates constitute from 40 to 95 percent by volume of a given gasoline blend. For aromatics, toluene (91.25 percent C) lies in the middle of the possible range. This range is bounded by cumene (89.94 percent C) and naphthalene (93.71 percent C). Total aromatics may make up between 3 and 50 percent by volume of any given gasoline blend. The range of these potential values contributes to the uncertainty surrounding the final calculated C factors.

However, as demonstrated above in Figure A-3, the amount of variation in C content of gasoline is restricted by the compounds in the fuel to ±4 percent. Further, despite variation in sampling survey response, sample size and annually variable fuel formulation requirements, the observed variation in the annual weighted motor gasoline coefficients estimated for this Inventory is ±0.8 percent over 1990 through 2019.

The third primary contributor to uncertainty is the assumed heat content. The heat contents are industry standards established many years ago. The heat contents are standard conversion factors used by EIA to convert volumetric energy data to energy units. Because the heat contents of fuels change over time, without necessarily and directly altering their volume, the conversion of known volumetric data to energy units may introduce bias. Thus, a more precise approach to estimating emissions factors would be to calculate C content per unit of volume, rather than per unit of energy. Adopting this approach, however, makes it difficult to compare U.S. C content coefficients with those of other nations.

The changes in density of motor gasoline over the last decade suggest that the heat content of the fuels is also changing. However, that change within any season grade has been less than 1 percent over the decade. Of greater concern is the use of a standardized heat content across grades that show a variation in density of ±1.5 percent from the mean for conventional gasoline and ±1.0 percent for reformulated fuels.

Jet Fuel

Jet fuel is a refined petroleum product used in jet aircraft engines. There are two classes of jet fuel used in the United States: "naphtha-based" jet fuels and "kerosene-based" jet fuels. In 1989, 13 percent of U.S. consumption was naphtha-based fuel, with the remainder kerosene-based jet fuel. In 1993, the U.S. Department of Defense began a conversion from naphtha-based JP-4 jet fuel to kerosene-based jet fuel, because of the possibility of increased demand for reformulated motor gasoline limiting refinery production of naphtha-based jet fuel. By 1996, naphtha-based jet fuel represented less than one-half of one percent of all jet fuel consumption. The C content coefficient for jet fuel used in this report prior to 1996 represents a consumption-weighted combination of the naphtha-based and kerosene-based coefficients. From 1996 to 2019, only the kerosene-based portion of total consumption is considered significant.

Methodology

Step 1. Estimate the carbon content for naphtha-based jet fuels

Because naphtha-based jet fuels are used on a limited basis in the United States, sample data on its characteristics are limited. The density of naphtha-based jet fuel (49 degrees) was estimated as the central point of the acceptable API gravity range published by ASTM. The heat content of the fuel was assumed to be 5.355 MMBtu per barrel based on EIA industry standards. The C fraction was derived from an estimated hydrogen content of 14.1 percent (Martel and Angello 1977), and an estimated content of sulfur and other non-hydrocarbons of 0.1 percent.

Step 2. Estimate the carbon content for kerosene-based jet fuels

The density of kerosene-based jet fuels was estimated at 42 degrees API and the carbon share at 86.3 percent. The density estimate was based on 38 fuel samples examined by NIPER. Carbon share was estimated on the basis of a hydrogen content of 13.6 percent found in fuel samples taken in 1959 and reported by Martel and Angello, and on an assumed sulfur content of 0.1 percent. The EIA's standard heat content of 5.670 MMBtu per barrel was adopted for kerosene-based jet fuel.

Step 3. Weight the overall jet fuel carbon content coefficient for consumption of each type of fuel (1990-1995 only)

For years 1990 through 1995, the C content for each jet fuel type (naphtha-based, kerosene-based) is multiplied by the share of overall consumption of that fuel type, as reported by EIA (2009a). Individual coefficients are then summed and totaled to yield an overall C content coefficient. Only the kerosene-based C coefficient is reflected in the overall jet fuel coefficient for 1996 through 2019.

Data Sources

Data on the C content of naphtha-based jet fuel was taken from C.R. Martel and L.C. Angello (1977). Data on the density of naphtha-based jet fuel was taken from ASTM (1985). Standard heat contents for kerosene and naphtha-based jet fuels were adopted from EIA (2009a). Data on the C content of kerosene-based jet fuel is based on C.R. Martel and L.C. Angello (1977) and the density is derived from NIPER (1993).

Uncertainty

Variability in jet fuel is relatively small with the average C share of kerosene-based jet fuel varying by less than ±1 percent and the density varying by ±1 percent. This is because the ratio of fuel mass to useful energy must be tightly bounded to maximize safety and range. There is more uncertainty associated with the density and C share of naphtha-based jet fuel because sample data were unavailable and default values were used. This uncertainty has only a small impact on the overall uncertainty of the C content coefficient for jet fuels, however, because naphtha-based jet fuel represents a small and declining share of total jet fuel consumption in the United States and is treated as negligible when calculating C content factors for 1996 onward.

Distillate Fuel

Distillate fuel is a general classification for diesel fuels and fuel oils. Products known as No. 1, No. 2, and No. 4 diesel fuel are used in on-highway diesel engines, such as those in trucks and automobiles, as well as off-highway engines, such as those in railroad locomotives and agricultural machinery. No. 1, No. 2, and No. 4 fuel oils are also used for space heating and electric power generation.

Methodology

For this Inventory, separate C coefficients have been estimated for each of the three distillates, although the level of aggregation of U.S. energy statistics requires that a single coefficient is used to represent all three grades in inventory calculations. In past Inventories, the emission coefficient was only determined for distillate No. 2. Distillate No. 2 remains the representative grade applied to the distillate class for calculation purposes. Coefficients developed for No. 1 and No. 4 distillate are provided for informational purposes. The C share for distillate No. 1 and No. 4 is drawn from *Perry's Chemical Engineers' Handbook, 8th Ed*. (Green & Perry 2008). Each C share was combined with individual heat contents of 5.822 and 6.135 MMBtu per barrel, respectively for distillates No. 1 and No. 4, and densities of 35.3 and 23.2 degrees API to calculate C coefficients for each distillate type.

The carbon content of diesel fuel No. 2 is calculated according to ASTM D3343, Standard Test Method for the Estimation of Hydrogen Content of Aviation Fuels, and ASTM D3338, Standard Test Method for the Net Heat of Combustion of Aviation Fuels, using fuel properties inputs from the Alliance of North American Fuel Survey (NAFS) data for each year and season. These methods use a correlation between the measured fuel distillation range, API gravity, and aromatic content to estimate the hydrogen content.

Data Sources

Fuel properties for distillate No. 2 were derived from diesel surveys taken by the Alliance of Automobile Manufacturers, an association which is now part of the Alliance for Automotive Innovation. The density of distillate fuel oil No. 4 is taken from *Perry's Chemical Engineer's Handbook, 8th Ed*. (Green & Perry, ed. 2008), Table 24-6.

Heat contents are adopted from EIA (2020a), and carbon shares for distillates No. 1 and No. 4 are from *Perry's Chemical Engineers' Handbook* (Green & Perry, ed. 2008), Table 24-6.

Uncertainty

The primary source of uncertainty for the estimated C content of distillate fuel is the selection of No. 2 distillate as the typical distillate fuel oil or diesel fuel. No. 2 fuel oil is generally consumed for home heating. No. 1 distillate is generally less dense and if it is consumed in large portions for mobile sources, the application of the C content estimated for No. 2 for this report is likely to be too high when applied to both No. 1 and No. 2 distillates. The opposite is true of the application of a coefficient based upon the properties of No. 2 to the consumption of No. 4 distillate, which is of a significantly higher density and thus, has a higher C coefficient despite its lower C share. The overall effect on uncertainty from applying a single factor will depend on the relative annual consumption of each distillate.

The densities applied to the calculation of each carbon factor are an underlying a source of uncertainty. While the density of No. 1 distillate is based upon just four samples, the factor applied to all distillates in the Inventory estimates (that for No. 2 oil) is based on a much larger sample size (144). Given the range of densities for these three distillate fuel classes (0.1342 to 0.1452 MT/bbl at 60 degrees F), the uncertainty associated with the assumed density of distillate fuels is predominately a result of the use of No. 2 to represent all distillate consumption. There is also a small amount of uncertainty in the No. 2 distillate density itself. This is due to the possible variation across seasonal diesel formulations and fuel grades and between stationary and transport applications within the No. 2 distillate classification. The range of the density of the samples of No. 2 diesel (regular grade, 15 ppm sulfur) is ± 2.5 percent from the mean, while the range in density across the small sample set of No. 1 diesel is -2.1 to +1.6 percent of the mean. Samples from AAM (2009) of Premium No. 2 diesel (n=5) and higher sulfur (500 ppm S) regular diesel (n=2), each have nominally higher average densities (+1.3 percent and +0.6 percent, respectively) than do the low-sulfur regular diesel samples that underlie the density applied in this Inventory.

The use of the 144 AAM samples to define the density of No. 2 distillate (and those four samples used to define that of No. 1 distillate) may introduce additional uncertainty because the samples were collected from just one season of on-road fuel production (Winter 2008). Despite the limited sample frame, the average No. 2 density calculated from the samples is applied to the calculation of a uniform C coefficient applicable for all years of the Inventory and for all types of distillate consumption. The ASTM standards for each grade of diesel fuel oil do not include a required range in which the density must lie, and the density (as well as heat content and carbon share) may vary according to the additives in each seasonal blend and the sulfur content of each sub-grade.

However, previous studies also show relatively low variation in density across samples of No. 2 and across all distillates, supporting the application of a single No. 2 density to all U.S. distillate consumption. The average density calculated from samples analyzed by the EIA in 1994 (n=7) differs only very slightly from the value applied for the purposes of this Inventory (-0.12 percent for No. 2 distillate). Further, the difference between the mean density applied to this Inventory (No. 2 only) and that calculated from EIA samples of all distillates, regardless of grade, is also near zero (-0.06 percent, based on n=14, of distillates No. 1, No. 2 and No. 4 combined).

A C share of 87.30 percent is applied to No. 2 distillate, while No. 1 and No. 4 have C shares estimated at 86.40 and 86.47 percent, respectively. Again, the application of parameters specific to No. 2 to the consumption of all three distillates contributes to an increased level of uncertainty in the overall coefficient and emissions estimate and its broad application. For comparison, four No. 1 fuel oil samples obtained by EIA (1994) contained an average of 86.19 percent C, while seven samples No. 2 fuel oil from the same EIA analysis showed an average of 86.60 percent C. Additionally, three samples of No. 4 distillate indicate an average C share of 85.81 percent. The range of C share observed across the seven No. 2 samples is 86.1 to 87.5 percent, and across all samples (all three grades, n=14) the range is 85.3 to 87.5 percent C. There also exists an uncertainty of ±1 percent in the share of C in No. 2 based on the limited sample size.

Residual Fuel

Residual fuel is a general classification for the heavier oils, known as No. 5 and No. 6 fuel oils, that remain after the distillate fuel oils and lighter hydrocarbons are distilled away in refinery operations. Residual fuel conforms to ASTM Specifications D 396 and D 975 and Federal Specification VV-F-815C. No. 5, a residual fuel oil of medium viscosity, is also known as Navy Special and is defined in Military Specification MIL-F-859E, including Amendment 2 (NATO Symbol F-770). It is used in steam-powered vessels in government service and inshore power plants. No. 6 fuel oil includes Bunker C fuel oil and is used for the production of electric power, space heating, vessel bunkering, and various industrial purposes.

In the United States, electric utilities purchase about one-third of the residual oil consumed. A somewhat larger share is used for vessel bunkering, and the balance is used in the commercial and industrial sectors. The residual oil (defined as No. 6 fuel oil) consumed by electric utilities has an energy content of 6.287 MMBtu per barrel (EIA 2008a) and an average sulfur content of 1 percent (EIA 2001). This implies a density of about 17 degrees API.

Methodology

Because U.S. energy consumption statistics are available only as an aggregate of No. 5 and No. 6 residual oil, a single coefficient must be used to represent the full residual fuel category. As in earlier editions of this report, residual fuel oil has been defined as No. 6 fuel oil, due to the majority of residual consumed in the United States being No. 6.

However, for this report, a separate coefficient for fuel oil No. 5 has also been developed for informational purposes. Densities of 33.0 and 15.5 degrees API were adopted when developing the C content coefficients for Nos. 5 and 6, respectively (Wauquier, J.-P., ed. 1995; Green & Perry, ed. 2008).

The estimated C share of fuel oil No. 5 is 85.67 percent, based on an average of 12 ultimate analyses of samples of fuel oil (EIA 1994). An average share of C in No. 6 residual oil of 84.67 percent by mass was used, based on Perry's, 8th Ed. (Green & Perry, ed. 2008).

Data Sources

Data on the C share and density of residual fuel oil No. 6 were obtained from Green & Perry, ed. (2008). Data on the C share of fuel oil No. 5 was adopted from EIA (1994), and the density of No. 5 was obtained from Wauquier, J.-P., ed. (1995). Heat contents for both No. 5 and No. 6 fuel oil are adopted from EPA (2009b).

Uncertainty

Beyond the application of a C factor based upon No. 6 oil to all residual oil consumption, the largest source of uncertainty in estimating the C content of residual fuel centers on the estimates of density. Fuel oils are likely to differ depending on the application of the fuel (i.e., power generation or as a marine vessel fuel). Slight differences between the density of residual fuel used by utilities and that used in mobile applications are likely attributable to non-sulfur impurities, which reduce the energy content of the fuel, but do not greatly affect the density of the product. Impurities of several percent are commonly observed in residual oil. The extent of the presence of impurities has a greater effect on the uncertainty of C share estimation than it does on density. This is because these impurities do provide some Btu content to the fuel, but they are absent of carbon. Fuel oils with significant sulfur, nitrogen and heavy metals contents would have a different total carbon share than a fuel oil that is closer to pure hydrocarbon. This contributes to the uncertainty of the estimation of an average C share and C coefficient for these varied fuels.

The 12 samples of residual oil (EIA 1994) cover a density range from 4.3 percent below to 8.2 percent above the mean density. The observed range of C share in these samples is -2.5 to +1.8 percent of the mean. Overall, the uncertainty associated with the C content of residual fuel is probably ±1 percent.

Hydrocarbon Gas Liquids (HGL)

EIA identifies four categories of paraffinic hydrocarbons (i.e., ethane, propane, isobutane, and n-butane) and four categories of olefinic hydrocarbons (i.e., ethylene, propylene, isobutylene, and butylene) as HGL. HGL also includes pentanes plus, or natural gasoline, but this category is calculated separately from other HGL components in this report. Because each of these compounds is a pure paraffinic or olefinic hydrocarbon, their C shares are easily derived by taking into account the atomic weight of C (12.01) and the atomic weight of hydrogen (1.01). Thus, for example, the C share of propane, C_3H_8, is 81.71 percent. The densities and heat contents of the compounds are also well known, allowing C content coefficients to be calculated directly. Table A-40 summarizes the physical characteristic of HGL.

Table A-40: Physical Characteristics of Hydrocarbon Gas Liquids

Compound	Chemical Formula	Density (Barrels Per Metric Ton)	Carbon Content (Percent)	Energy Content (MMBtu/Barrel)	Carbon Content Coefficient (MMT C/QBtu)
Ethane	C_2H_6	11.55	80.00	2.783	16.25
Propane	C_3H_8	12.76	81.80	3.841	17.15
Isobutane	C_4H_{10}	11.42	82.80	4.183	17.71
n-butane	C_4H_{10}	10.98	82.30	4.354	17.66
Ethylene	C_2H_4	11.07	85.71	2.436	17.99
Propylene	C_3H_6	12.45	85.71	3.835	17.99
Isobutylene	C_4H_8	10.68	85.71	4.355	18.78
Butylene	C_4H_8	10.70	85.71	4.377	18.74

Source: Densities – CRC Handbook of Chemistry and Physics (2008/09) and EPA (2009c); Carbon Contents – derived from the atomic weights of the elements EPA (2013); Energy Contents – EIA (2020a). All values are for the compound in liquid form. The density and energy content of ethane are for refrigerated ethane (-89 degrees C). Values for n-butane are for pressurized butane (-25 degrees C).

Methodology

Step 1. Assign carbon content coefficients to each pure paraffinic compound

Based on their known physical characteristics, a C content coefficient is assigned to each compound contained in the U.S. energy statistics category, HGL.

Step 2. Weight individual HGL coefficients for share of fuel use consumption

A C content coefficient for HGL used as fuel is developed based on the consumption mix of the individual compounds reported in U.S. energy statistics, excluding pentanes plus, which is calculated separately.

Step 3. Weight individual HGL coefficients for share of non-fuel use consumption

The mix of HGL consumed for non-fuel use differs significantly from the mix of HGL that is combusted. EIA (2020a) states that HGL consumption in the residential, commercial, and transportation sector is 100 percent propane, therefore a constant, non-weighted propane C content coefficient is applied to HGL (LPG – Propane) in these sectors. While the majority of HGL consumed for fuel use in the industrial sector is propane, ethane is the largest component of HGL used for non-fuel applications. C content coefficients for HGL used for fuel use and non-fuel applications are developed based on the consumption mix of the individual compounds reported in U.S. energy statistics.

Step 4. Weight the carbon content coefficients for fuel use and non-fuel use by their respective shares of consumption

The changing shares of HGL fuel use and non-fuel use consumption appear below in Table A-41.

Data Sources

Data on C share was derived via calculations based on atomic weights of each element of the four individual compounds densities are from the CRC Handbook of Chemistry and Physics, 89th Education. The energy content of each HGL is from EIA (2020a). HGL consumption was based on data obtained from EIA (2020b). Non-fuel use of HGL was obtained from EIA (2020b).

Uncertainty

Because HGL consists of pure paraffinic and olefinic compounds whose density, heat content, and C share are physical constants, there is limited uncertainty associated with the C content coefficient for this petroleum product. Any uncertainty is associated with the collection of data tabulating fuel- and non-fuel consumption in U.S. energy statistics. This uncertainty is likely less than ±3 percent.

Table A-41: Industrial Sector Consumption and Carbon Content Coefficients of Hydrocarbon Gas Liquids, 1990-2019

	1990	1995	2000	2005	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Energy Consumption (QBtu)														
Fuel Use	**0.96**	**0.78**	**1.95**	**1.00**	**9.21**	**9.09**	**9.26**	**10.28**	**9.52**	**9.65**	**9.43**	**9.10**	**9.85**	**9.78**
Ethane	0.02	0.02	0.03	0.02	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.06
Propane	0.60	0.47	1.19	0.64	6.28	6.28	6.38	7.15	6.42	6.38	6.16	5.92	6.55	6.41
Butane	0.11	0.07	0.17	0.09	0.50	0.33	0.37	0.57	0.57	0.62	0.41	0.19	0.17	0.25
Isobutane	0.02	0.04	0.14	0.02	0.12	0.15	0.19	0.28	0.29	0.46	0.60	0.65	0.75	0.88
Ethylene	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Propylene	0.21	0.17	0.42	0.23	2.25	2.28	2.28	2.26	2.19	2.18	2.23	2.27	2.29	2.20
Butylene	+	+	+	+	0.02	+	+	(0.02)	0.01	(0.03)	(0.01)	0.02	0.04	+
Isobutylene	+	+	+	+	+	0.01	+	(+)	(+)	(+)	+	+	(+)	+
Non-Fuel Use	**1.88**	**2.35**	**2.61**	**2.48**	**1.80**	**1.85**	**1.88**	**2.04**	**2.03**	**2.10**	**2.13**	**2.19**	**2.51**	**2.58**
Ethane	0.48	0.61	0.71	0.63	0.88	0.96	0.96	1.01	1.05	1.09	1.15	1.26	1.50	1.56
Propane	0.89	1.09	1.17	1.21	0.57	0.57	0.57	0.64	0.58	0.57	0.55	0.53	0.59	0.58
Butane	0.16	0.17	0.17	0.16	0.11	0.07	0.08	0.13	0.13	0.14	0.09	0.04	0.04	0.06
Isobutane	0.03	0.10	0.14	0.04	0.03	0.03	0.04	0.06	0.07	0.10	0.14	0.15	0.17	0.20
Ethylene	+	+	+	+	0.01	0.01	+	+	+	+	+	+	+	+
Propylene	0.31	0.38	0.41	0.43	0.20	0.21	0.20	0.20	0.20	0.20	0.20	0.20	0.21	0.20

Butylene	+		+		+		+		+	+	+	(+)	+	(0.01)	(+)	+	0.01	+
Isobutylene	+		+		+		+		+	+	+	(+)	(+)	(+)	+	+	(+)	+
Carbon Content (MMT C/QBtu)																		
Fuel Use	17.51		17.51		17.52		17.45		17.43	17.40	17.41	17.39	17.41	17.43	17.43	17.45	17.45	17.47
Non-Fuel Use	17.24		17.25		17.22		17.19		16.93	16.84	16.86	16.88	16.86	16.89	16.85	16.84	16.82	16.85

Notes: "+" indicates a value less than 0.01 QBtu. Parentheses indicate negative values.

Sources: Fuel use of HGL based on data from EIA (2020b). Non-fuel use of HGL from (EIA 2020b). Volumes converted using the energy contents provided in Table A-40. C contents from EPA (2013).

Aviation Gasoline

Aviation gasoline is used in piston-powered airplane engines. It is a complex mixture of relatively volatile hydrocarbons with or without small quantities of additives, blended to form a fuel suitable for use in aviation reciprocating engines. Fuel specifications are provided in ASTM Specification D910 and Military Specification MIL-G-5572. Aviation gas is a relatively minor contributor to greenhouse gas emissions compared to other petroleum products, representing approximately 0.1 percent of all consumption.

The ASTM standards for boiling and freezing points in aviation gasoline effectively limit the aromatics content to a maximum of 25 percent (ASTM D910). Because weight is critical in the operation of an airplane, aviation gas must have as many Btu per pound (implying a lower density) as possible, given other requirements of piston engines such as high anti-knock quality.

Methodology

A C content coefficient for aviation gasoline was calculated on the basis of the EIA standard heat content of 5.048 MMBtu per barrel. This implies a density of approximately 69 degrees API gravity or 5.884 pounds per gallon, based on the relationship between heat content and density of petroleum liquids, as described in *Thermal Properties of Petroleum Products* (DOC 1929). To estimate the share of C in the fuel, it was assumed that aviation gasoline is 87.5 percent iso-octane, 9.0 percent toluene, and 3.5 percent xylene. The maximum allowable sulfur content in aviation gasoline is 0.05 percent, and the maximum allowable lead content is 0.1 percent. These amounts were judged negligible and excluded for the purposes of this analysis. This yielded a C share of 85.00 percent and a C content coefficient of 18.86 MMT C/QBtu.

Data Sources

Data sources include ASTM (1985). A standard heat content for aviation gas was adopted from EIA (2009a).

Uncertainty

The relationship used to calculate density from heat content has an accuracy of five percent at 1 atm. The uncertainty associated with the C content coefficient for aviation gasoline is larger than that for other liquid petroleum products examined because no ultimate analyses of samples are available. Given the requirements for safe operation of piston-powered aircraft the composition of aviation gas is well bounded, and the uncertainty of the C content coefficient is likely to be ±5 percent.

Still Gas

Still gas, or refinery gas, is composed of light hydrocarbon gases that are released as petroleum is processed in a refinery. The composition of still gas is highly variable, depending primarily on the nature of the refining process and secondarily on the composition of the product being processed. Petroleum refineries produce still gas from many different processes. Still gas can be used as a fuel or feedstock within the refinery, sold as a petrochemical feedstock, or purified and sold as pipeline-quality natural gas. For the purposes of this Inventory, the coefficient derived here is only applied to still gas that is consumed as a fuel. In general, still gas tends to include large amounts of free hydrogen and methane, as well as smaller amounts of heavier hydrocarbons. Because different refinery operations result in different gaseous by-products, it is difficult to determine what represents typical still gas.

Methodology

The properties of still gas used to calculate the carbon content are taken from the literature. The carbon share of still gas was calculated from its net calorific value and carbon content from IPCC (2006). This calculation yields a carbon share of 77.7 percent. The density of still gas was estimated to be 0.1405 metric tons per barrel based on its heat content (EIA 2008a) and the relationship between heat content and density that is described by the U.S. Department of Commerce, Bureau of Standards (DOC 1929).

Data Sources

The carbon share of still gas is calculated from data provided by IPCC (2006). Density is estimated at 0.1405 metric tons per barrel, approximately 28.3 degrees API, based on the heat content of 6.00 MMbtu/barrel of still gas from EIA (2009a).

Uncertainty

The EIA obtained data on four samples of still gas. Table A-42 below shows the composition of those samples.

Table A-42: Composition, Energy Content, and Carbon Content Coefficient for Four Samples of Still Gas

Sample	Hydrogen (%)	Methane (%)	Ethane (%)	Propane (%)	Btu Per Cubic Foot	Carbon Content (MMT C/QBtu)
One	12.7	28.1	17.1	11.9	1,388	17.51
Two	34.7	20.5	20.5	6.7	1,143	14.33
Three	72.0	12.8	10.3	3.8	672	10.23
Four	17.0	31.0	16.2	2.4	1,100	15.99

Sources: EIA (2008b).

Because the composition of still gas is highly heterogeneous, the C content coefficient for this product is highly uncertain. Gas streams with a large, free-hydrogen content are likely to be used as refinery or chemical feedstocks. Therefore, the sample cited above with the very high H content of 72 percent (and the lowest calculated C content) is less likely to be representative of the still gas streams to which the calculated coefficient is applied. The C content coefficient used for this report is probably at the high end of the plausible range given that it is higher than the greatest sample-based C content in Table A-42.

Asphalt

Asphalt is used to pave roads. Because most of its C is retained in those roads, it is a small source of carbon dioxide emissions. It is derived from a class of hydrocarbons called “asphaltenes,” which are abundant in some crude oils but not in others. Asphaltenes have oxygen and nitrogen atoms bound into their molecular structure, so that they tend to have lower C contents than do other hydrocarbons.

Methodology

Ultimate analyses of twelve samples of asphalts showed an average C content of 83.47 percent. The EIA standard Btu content for asphalt of 6.636 MMBtu per barrel was assumed. The ASTM petroleum measurement tables show a density of 5.6 degrees API or 8.605 pounds per gallon for asphalt. Together, these variables generate C content coefficient of 20.55 MMT C/QBtu.

Data Sources

A standard heat content for asphalt was adopted from EIA (2009b). The density of asphalt was determined by the ASTM (1985). C share is adopted from analyses in EIA (2008b).

Uncertainty

The share of C in asphalt ranges from 79 to 88 percent by weight. Also present in the mixture are hydrogen and sulfur, with shares by weight ranging from seven to 13 percent for hydrogen, and from trace levels to eight percent for sulfur. Because C share and total heat content in asphalts do vary systematically, the overall C content coefficient is likely to be accurate to ±5 percent.

Lubricants

Lubricants are substances used to reduce friction between bearing surfaces, or incorporated into processing materials used in the manufacture of other products, or used as carriers of other materials. Petroleum lubricants may be produced either from distillates or residues. Lubricants include all grades of lubricating oils, from spindle oil to cylinder oil to those used in greases. Lubricant consumption is dominated by motor oil for automobiles, but there is a large range of product compositions and end uses within this category.

Methodology

The ASTM Petroleum Measurement tables give the density of lubricants at 25.6 degrees API, or 0.1428 metric tons per barrel. Ultimate analysis of a single sample of motor oil yielded a C content of 85.80 percent. A standard heat content of 6.065 MMBtu per barrel was adopted from EIA. These factors produce a C content coefficient of 20.20 MMT C/QBtu.

Data Sources

A standard heat content was adopted from the EIA (2009b). The carbon content of lubricants is adopted from ultimate analysis of one sample of motor oil (EPA 2009a). The density of lubricating oils was determined by ASTM (1985).

Uncertainty

Uncertainty in the estimated C content coefficient for lubricants is driven by the large range of product compositions and end uses in this category combined with an inability to establish the shares of the various products captured under this category in U.S. energy statistics. Because lubricants may be produced from either the distillate or residual fractions during refineries, the possible C content coefficients range from 19.89 MMT C/QBtu to 21.48 MMT C/QBtu or an uncertainty band from –1.5 percent to +1.4 percent of the estimated value.

Petrochemical Feedstocks

U.S. energy statistics distinguish between two different kinds of petrochemical feedstocks: those with a boiling temperature below 400 degrees Fahrenheit, generally called "naphtha," and those with a boiling temperature 401 degrees Fahrenheit and above, referred to as "other oils" for the purposes of this Inventory.

Methodology

The C content of these petrochemical feedstocks are estimated independently according to the following steps.

Step 1. Estimate the carbon content coefficient for naphtha

Because reformed naphtha is used to make motor gasoline (hydrogen is released to raise aromatics content and octane rating), "straight-run" naphtha is assumed to be used as a petrochemical feedstock. Ultimate analyses of five samples of naphtha were examined and showed an average C share of 84.11 percent. A density of 62.4 degrees API gravity was taken from the *Handbook of Petroleum Refining Processes*, 3rd ed. (Meyers 2004). The standard EIA heat content of 5.248 MMBtu per barrel is used to estimate a C content coefficient of 18.55 MMT C/QBtu.

Step 2. Estimate the carbon content coefficient for petrochemical feedstocks with a boiling temperature 400 degrees Fahrenheit and above ("other oils")

The boiling temperature of this product places it into the "middle distillate" fraction in the refining process, and EIA estimates that these petrochemical feedstocks have the same heat content as distillate fuel No. 2. Thus, the C content coefficient of 20.17 MMT C/QBtu used for distillate fuel No. 2 is also adopted for this portion of the petrochemical feedstocks category.

Data Sources

Naphthas: Data on the C content was taken from Unzelman (1992). Density is from Meyers (2004). A standard heat content for naphthas was adopted from EIA (2009a). Other oils: See Distillate Fuel, Distillate No.2.

Uncertainty

Petrochemical feedstocks are not so much distinguished on the basis of chemical composition as on the identity of the purchaser, who are presumed to be a chemical company, or a petrochemical unit co-located on the refinery grounds. Naphthas are defined, for the purposes of U.S. energy statistics, as those naphtha products destined for use as a petrochemical feedstock. Because naphthas are also commonly used to produce motor gasoline, there exists a considerable degree of uncertainty about the exact composition of petrochemical feedstocks.

Different naphthas are distinguished by their density and by the share of paraffins, isoparaffins, olefins, naphthenes and aromatics contained in the oil. Naphtha from the same crude oil fraction may have vastly different properties depending on the source of the crude. Two different samples of Egyptian crude, for example, produced two straight run naphthas having naphthene and paraffin contents (percent volume) that differ by 18.1 and 17.5 percent, respectively (Matar and Hatch 2000).

Naphthas are typically used either as a petrochemical feedstock or a gasoline feedstock, with lighter paraffinic naphthas going to petrochemical production. Naphthas that are rich in aromatics and naphthenes tend to be reformed or blended into gasoline. Thus, the product category encompasses a range of possible fuel compositions, creating a range of possible C shares and densities. The uncertainty associated with the calculated C content of naphthas is primarily a function of the uncertainty that underlies the average carbon share calculation, which is based on a limited number of samples. Two additional samples cited by the EIA (1994) have a range of 83.80 to 84.42 percent C.

The uncertainty of the C content for other oils is based upon the assumption of distillate oil No. 2 as a product representative of the ill-defined classification of "other oils," and from the calculation of the C content of No. 2 itself (see "Distillate Fuels," above). While No. 2 distillate is used as a proxy for "other oils" for the purposes of this Inventory's carbon coefficient, important differences exist between these two petroleum products, contributing some uncertainty to the cross-application. Other oils are defined herein as those "oils with a boiling range equal to or greater than 401 degrees F that are generally intended for use as a petrochemical feedstock and are not defined elsewhere." For comparison, various material safety data sheets (MSDSs) published by producers of distillate No. 2 indicate a boiling range for this product of 320 to 700 degrees Fahrenheit. The relatively open definition of the classification "other oils" leaves room for potentially significant variation in the heating value, density and carbon share properties of each feedstock oil having a boiling point above 400 degrees Fahrenheit, creating a large band of uncertainty beyond that associated with the C factor for distillate No. 2.

Kerosene

A light petroleum distillate that is used in space heaters, cook stoves, and water heaters and is suitable for use as a light source when burned in wick-fed lamps, kerosene is drawn from the same petroleum fraction as jet fuel. Kerosene is generally comparable to No. 1 distillate oil.

Methodology

The average density and C share of kerosene are assumed to be the same as those for distillate No. 1 since the physical characteristics of the products are very similar. Thus, a density of 35.3 degrees API and average C share of 86.40 percent were applied to a standard heat content for distillate No. 1 of 5.825 MMBtu per barrel to yield a C content coefficient of 19.96 MMT C/QBtu.

Data Sources

A standard heat content for distillate No. 1 was adopted from EIA (2009a).

Uncertainty

Uncertainty in the estimated C content for kerosene is driven by the selection of distillate No. 1 as a proxy for kerosene. If kerosene is more like kerosene-based jet fuel, the true C content coefficient is likely to be some 1.3 percent lower. If kerosene is more aptly compared to No. 2 distillate oil, then the true C content coefficient is likely to be about 1.1 percent higher. While kerosene is a light petroleum distillate, like distillate No. 1, the two oil classes have some variation in their properties. For example, the boiling range of kerosene is 250 to 550 degrees Fahrenheit, whereas No. 1 oils typically boil over a range from 350 to 615 degrees Fahrenheit. The properties of individual kerosenes will vary with their use and particular crude origin, as well. Both kerosene and fuel oil No. 1 are primarily composed of hydrocarbons having 9 to 16 carbon atoms per molecule. However, kerosene is a straight-run No. 1 fuel oil, additional cracking processes and additives contribute to the range of possible fuels that make up the broader distillate No. 1 oil category.

Petroleum Coke

Petroleum coke is the solid residue by-product of the extensive processing of crude oil. It is a coal-like solid, usually has a C content greater than 90 percent, and is used as a boiler fuel and industrial raw material.

Methodology

Ultimate analyses of two samples of petroleum coke showed an average C share of 92.28 percent. The ASTM standard density of 9.543 pounds per gallon was adopted and the EIA standard energy content of 6.024 MMBtu per barrel assumed. Together, these factors produced an estimated C content coefficient of 27.85 MMT C/QBtu.

Data Sources

C content was derived from two samples from Martin, S.W. (1960). The density of petroleum coke was taken from the ASTM (1985). A standard heat content for petroleum coke was adopted from EIA (2009a).

Uncertainty

The uncertainty associated with the estimated C content coefficient of petroleum coke can be traced to two factors: the use of only two samples to establish C contents and a standard heat content which may be too low. Together, these uncertainties are likely to bias the C content coefficient upwards by as much as 6 percent.

Special Naphtha

Special naphtha is defined as a light petroleum product to be used for solvent applications, including commercial hexane and four classes of solvent: (1) Stoddard solvent, used in dry cleaning; (2) high flash point solvent, used as an industrial paint because of its slow evaporative characteristics; (3) odorless solvent, most often used for residential paints; and (4) high solvency mineral spirits, used for architectural finishes. These products differ in both density and C percentage, requiring the development of multiple coefficients.

Methodology

The method for estimating the C content coefficient of special naphtha includes three steps.

Step 1. Estimate the carbon content coefficient for hexane

Hexane is a pure paraffin containing 6 C atoms and 14 hydrogen atoms; thus, it is 83.63 percent C. Its density is 83.7 degrees API or 5.477 pounds per gallon and its derived C content coefficient is 21.40 MMT C/QBtu.

Step 2. Estimate the carbon contents of non-hexane special naphthas

The hydrocarbon compounds in special naphthas are assumed to be either paraffinic or aromatic (see discussion above). The portion of aromatics in odorless solvents is estimated at less than 1 percent, Stoddard and high flash point solvents contain 15 percent aromatics and high solvency mineral spirits contain 30 percent aromatics (Boldt and Hall 1977). These assumptions, when combined with the relevant densities, yield the C content factors contained in Table A-43, below.

Table A-43: Characteristics of Non-hexane Special Naphthas

Special Naphtha	Aromatic Content (Percent)	Density (Degrees API)	Carbon Share (Percent Mass)	Carbon Content (MMT C/QBtu)
Odorless Solvent	1	55.0	84.51	19.41
Stoddard Solvent	15	47.9	84.44	20.11
High Flash Point	15	47.6	84.70	20.17
Mineral Spirits	30	43.6	85.83	20.99

Sources: EIA (2008b) and Boldt and Hall (1977).

Step 3. Develop weighted carbon content coefficient based on consumption of each special naphtha

EIA reports only a single consumption figure for special naphtha. The C contents of the five special naphthas are weighted according to the following formula: approximately 10 percent of all special naphtha consumed is hexane; the remaining 90 percent is assumed to be distributed evenly among the four other solvents. The resulting emissions coefficient for special naphthas is 19.74 MMT C/QBtu.

Data Sources

A standard heat content for special naphtha was adopted from EIA (2009a). Density and aromatic contents were adopted from Boldt and Hall (1977).

Uncertainty

The principal uncertainty associated with the estimated C content coefficient for special naphtha is the allocation of overall consumption across individual solvents. The overall uncertainty is bounded on the low end by the C content of odorless solvent and on the upper end by the C content of hexane. This implies an uncertainty band of –1.7 percent to +8.4 percent.

Petroleum Waxes

The ASTM standards define petroleum wax as a product separated from petroleum that is solid or semi-solid at 77 degrees Fahrenheit (25 degrees Celsius). The two classes of petroleum wax are paraffin waxes and microcrystalline waxes. They differ in the number of C atoms and the type of hydrocarbon compounds. Microcrystalline waxes have longer C chains and more variation in their chemical bonds than paraffin waxes.

Methodology

The method for estimating the C content coefficient for petroleum waxes includes three steps.

Step 1. Estimate the carbon content of paraffin waxes

For the purposes of this analysis, paraffin waxes are assumed to be composed of 100 percent paraffinic compounds with a chain of 25 C atoms. The resulting C share for paraffinic wax is 85.23 percent and the density is estimated at 45 degrees API or 6.684 pounds per gallon.

Step 2. Estimate the carbon content of microcrystalline waxes

Microcrystalline waxes are assumed to consist of 50 percent paraffinic and 50 percent cycloparaffinic compounds with a chain of 40 C atoms, yielding a C share of 85.56 percent. The density of microcrystalline waxes is estimated at 36.7 degrees API, based on a sample of 10 microcrystalline waxes found in the *Petroleum Products Handbook* (Martin, S.W. 1960).

Step 3. Develop a carbon content coefficient for petroleum waxes by weighting the density and carbon content of paraffinic and microcrystalline waxes

A weighted average density and C content was calculated for petroleum waxes, assuming that wax consumption is 80 percent paraffin wax and 20 percent microcrystalline wax. The weighted average C content is 85.30 percent, and the weighted average density is 6.75 pounds per gallon. EIA's standard heat content for waxes is 5.537 MMBtu per barrel. These inputs yield a C content coefficient for petroleum waxes of 19.80 MMT C/QBtu.

Data Sources

Density of paraffin wax was taken from ASTM (1985). Density of microcrystalline waxes was derived from 10 samples found in Guthrie (1960). A standard heat content for petroleum waxes was adopted from EIA (2009a).

Uncertainty

Although there is considerable qualitative uncertainty associated with the allocation of petroleum waxes and microcrystalline waxes, the quantitative variation in the C contents for all waxes is limited to ± 1 percent because of the nearly uniform relationship between C and other elements in petroleum waxes broadly defined.

Crude Oil, Unfinished Oils, and Miscellaneous Products

U.S. energy statistics include several categories of petroleum products designed to ensure that reported refinery accounts "balance" and cover any "loopholes" in the taxonomy of petroleum products. These categories include crude oil, unfinished oils, and miscellaneous products. Crude oil is rarely consumed directly, miscellaneous products account for less than one percent of oil consumption, and unfinished oils are a balancing item that may show negative consumption. For C accounting purposes, it was assumed that all unfinished oils have the same C content as crude oil. The miscellaneous products category reported by EIA includes miscellaneous products that are not reported elsewhere in the EIA data set. According to EIA recovered sulfur compounds from petroleum and natural gas processing, and potentially carbon black feedstock could be reported in this category. Recovered sulfur has no carbon content and would not be reported in the Inventory. Based on this information, the miscellaneous products category reported by EIA was assumed to be mostly petroleum refinery sulfur compounds that do not contain carbon (EIA 2019). Therefore, the carbon content for miscellaneous products was assumed to be zero across the time series.

Methodology

EIA reports on the average density and sulfur content of U.S. crude oil purchased by refineries. To develop a method of estimating C content based on this information, results of ultimate analyses of 182 crude oil samples were collected. Within the sample set, C content ranged from 82 to 88 percent C, but almost all samples fell between 84 percent and 86 percent C. The density and sulfur content of the crude oil data were regressed on the C content, producing the following equation:

$$\text{Percent C} = 76.99 + (10.19 \times \text{Specific Gravity}) + (-0.76 \times \text{Sulfur Content})$$

Absent the term representing sulfur content, the equation had an R-squared of only 0.35.[26] When C content was adjusted to exclude sulfur, the R-squared value rose to 0.65. While sulfur is the most important non-hydrocarbon impurity, nitrogen and oxygen can also be significant, but they do not seem to be correlated with either density or sulfur content. Restating these results, density accounts for about 35 percent of the variation in C content, impurities account for about 30 percent of the variation, and the remaining 35 percent is accounted for by other factors, including (presumably) the degree to which aromatics and polynuclear aromatics are present in the crude oil. Applying this equation to the 2008 crude oil quality data (30.21 degrees API and 1.47 percent sulfur) produces an estimated C content of 84.79 percent. Applying the density and C content to the EIA standard energy content for crude oil of 5.800 MMBtu per barrel produced an emissions coefficient of 20.31 MMT C/QBtu.

Data Sources

Carbon content was derived from 182 crude oil samples, including 150 samples from U.S. National Research Council (1927). A standard heat content for crude oil was adopted from EIA (2009a).

Uncertainty

The uncertainty of the estimated C content for crude oil centers on the 35 percent of variation that cannot be explained by density and sulfur content. This variation is likely to alter the C content coefficient by ±3 percent. Since unfinished oils and miscellaneous products are impossible to define, the uncertainty of applying a crude oil C content is likely to be bounded by the range of petroleum products described in this chapter at ±10 percent.

Chronology and Explanation of Changes in Individual Carbon Content Coefficients of Fossil Fuels

The following section describes changes to carbon content coefficients of fossil fuels, organized by the calendar year in which the update was implemented. Additional information on which Inventory year these changes appear is provided within each section.

Coal

Original 1994 Analysis

A set of 5,426 coal samples from the EIA coal analysis file were used to develop C content estimates. The results from that sample set appear below in Table A-44. The EIA Coal Analysis File was originally developed by the U.S. Bureau of Mines and contained over 60,000 coal samples obtained through numerous coal seams throughout the United States. Many of the samples were collected starting in the 1940s and 1950s through the 1980s and analyzed in U.S. government laboratories. The coefficients developed in 1994 were in use for the 1990 through 2000 Inventory and are provided in Table A-44**.**

Table A-44: Carbon Content Coefficients for Coal by Consuming Sector and Coal Rank, 1990 – 2000 (MMT C/QBtu)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Consuming Sector											
Electric Power	25.68	25.69	25.69	26.71	25.72	25.74	25.74	25.76	25.76	25.76	25.76
Industrial Coking	25.51	25.51	25.51	25.51	25.52	25.53	25.55	25.56	25.56	25.56	25.56
Other Industrial	25.58	25.59	25.62	25.61	25.63	25.63	25.61	25.63	25.63	25.63	25.63

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[26] R-squared represents the percentage of variation in the dependent variable (in this case carbon content) explained by variation in the independent variables.

Residential/Commercial	25.92	26.00	26.13	25.97	25.95	26.00	25.92	26.00	26.00	26.00	26.00
Coal Rank											
Anthracite	28.13	28.13	28.13	28.13	28.13	28.13	28.13	28.13	28.13	28.13	28.13
Bituminous	25.37	25.37	25.37	25.37	25.37	25.37	25.37	25.37	25.37	25.37	25.37
Sub-bituminous	26.24	26.24	26.24	26.24	26.24	26.24	26.24	26.24	26.24	26.24	26.24
Lignite	26.62	26.62	26.62	26.62	26.62	26.62	26.62	26.62	26.62	26.62	26.62

Sources: Emission factors by consuming sector from B.D. Hong and E.R. Slatnick, "Carbon Dioxide Emission Factors for Coal, "U.S. EIA, *Quarterly Coal Report*, January-March 1994 (Washington, DC, 1994); and emission factors by rank from Science Applications International Corporation, *Analysis of the Relationship Between Heat and Carbon Content of U.S. Fuels: Final Task Report*, Prepared for the U.S. EIA, Office of Coal, Nuclear, Electric and Alternative Fuels (Washington, DC 1992).

Subsequent Updates

In 2002 a database compiled by the U.S. Geological Survey (USGS), CoalQual 2.0 (1998), was adopted to update the analysis. The updated sample set included 6,588 coal samples collected by the USGS and its state affiliates between 1973 and 1989. The decision to switch to the sample data contained in the USGS CoalQual database from the EIA database was made because the samples contained in the USGS database were collected and analyzed more recently than those obtained by EIA from the Bureau of Mines. The updated methodology first appeared in the 1990-2004 Inventory. The methodology employed for these estimates has remained unchanged since 2002,[27] however, the underlying coal data sample set has been updated over the years to integrate new data sets as they became available.

In 2010 sample data from the Energy Institute at Pennsylvania State University (504 samples) were added to the 6,588 USGS samples to create a new database of 7,092 samples. The new coefficients developed in the 2010 update were first implemented for the 1990 through 2008 Inventory.

In 2019 sample data from the Montana Bureau of Mines & Geology (908 samples), the Illinois State Geological Survey Coal Quality Database (460 samples), and the Indiana Geological Survey Coal Quality Database (745 samples) were used to calculate updated carbon contents by rank for Montana, Illinois, and Indiana. Combining revised carbon contents for these three states with the carbon contents for all other states calculated from the USGS and Pennsylvania State University samples yielded updated national average carbon contents by coal rank and end-use sector. The new coefficients developed in the 2019 update were first implemented for the 1990 through 2017 Inventory.

In 2021, carbon content coefficients for industrial coking coal were updated to be annually variable to align with the variability of other sectors and coal ranks. The new coefficients developed were first implemented for the current 1990 through 2019 Inventory. See Table A-32 and Table A-33 for the carbon content coefficients values used in this Inventory.

Natural Gas

Original 1994 Analysis

Prior to the 1990 through 2008 Inventory, descriptive statistics were used to stratify 6,743 samples of pipeline quality natural gas by heat content and then to determine the average C content of natural gas at the national average heat content (EIA 1994). The same coefficient was applied to all pipeline natural gas consumption for all years, because U.S. energy statistics showed a range of national average heat contents of pipeline gas of only 1,025 to 1,031 Btu per cubic foot (1 percent) from 1990 through 1994. A separate factor was developed in the same manner for all flared gas. Previously, a weighted national average C content was calculated using the average C contents for each sub-sample of gas that conformed with an individual state's typical cubic foot of natural gas since there is regional variation in energy content. The result was a weighted national average of 14.47 MMT C/QBtu.

2010 and 2019 Updates

A revised analytical methodology introduced in 2010 underlies the natural gas C coefficients used in this report. This methodology was first implemented in the 1990 through 2008 Inventory. The revised analysis conducted in 2010 used the same set of samples, but utilized a regression equation, as described above, of sample-based heat content and

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[27] In 2009, the analysis of the USGS Coal Qual data was updated to make a technical correction that affected the value for lignite and those sectors which consume lignite. The updated coefficients resulting from this correction were first implemented for the 1990 through 2007 Inventory.

carbon content data in order to calculate annually variable national average C content coefficients based on annual national average heat contents for pipeline natural gas and for flare gas. In addition, the revised analysis calculated an average C content from all samples with less than 1.5 percent CO_2 and less than 1,050 Btu/cf (samples most closely approximating the makeup of pipeline quality natural gas).

In 2019, this analysis was updated again to calculate annually variable national average C content coefficients for years 2009 through 2017 in the time series using heat contents published in EIA (2019). The resulting average was 14.43 MMT C/QBtu, which is slightly less than the previous weighted national average of 14.47 MMT C/QBtu. The 2019 update was first implemented in the 1990 through 2017 Inventory. The average C contents from the 1994 calculations are presented in Table A-45 below for comparison.

Table A-45: Carbon Content of Pipeline-Quality Natural Gas by Energy Content (MMT C/QBtu)

Sample	Average Carbon Content
GRI Full Sample	14.51
Greater than 1,000 Btu	14.47
1,025 to 1,035 Btu	14.45
975 to 1,000 Btu	14.73
1,000 to 1,025 Btu	14.43
1,025 to 1,050 Btu	14.47
1,050 to 1,075 Btu	14.58
1,075 to 1,100 Btu	14.65
Greater than 1,100 Btu	14.92
Weighted National Average	14.47

Source: EIA (1994).

Petroleum Products

2010 Update

All of the petroleum product C coefficients except that for Aviation Gasoline Blending Components were updated in 2010 for the 1990 through 2008 Inventory and held constant through the current Inventory. EPA updated these factors to better align the fuel properties data that underlie the Inventory factors with those published in EPA's *Mandatory Reporting of Greenhouse Gases Rule* (EPA 2009b), Suppliers of Petroleum Products (MM) and Stationary Combustion (C) subparts. The coefficients that were applied in previous reports are provided in Table A-46 below. Specifically, each of the coefficients used in this report have been calculated from updated density and C share data, largely adopted from analyses undertaken for the Greenhouse Gas Reporting Rule (EPA 2009b). In some cases, the heat content applied to the conversion to a carbon-per-unit-energy basis was also updated. Additionally, the category Misc. Products (U.S. Territories), which is based upon the coefficients calculated for crude oil, was allowed to vary annually with the crude oil coefficient. The petrochemical feedstock category was eliminated because the constituent products—naphthas and other oils—are estimated independently. Further, although the level of aggregation of U.S. energy statistics currently limits the application of coefficients for residual and distillate fuels to these two generic classifications, individual coefficients for the five major types of fuel oil (Nos. 1, 2, 4, 5 and 6) were estimated and are presented in Table A-38 above. Each of the C coefficients applied in previous Inventories are provided below for comparison (Table A-46).

Table A-46: Carbon Content Coefficients and Underlying Data for Petroleum Products

Fuel	Carbon Content (MMT C/QBtu)	Gross Heat of Combustion (MMBtu/Barrel)	Density (API Gravity)	Percent Carbon
Motor Gasoline	19.27	5.220	59.1	86.60
LPG (Propane)	17.15	3.841	155.3	81.80
HGL (Energy Use)[a]	17.47	(See b)	(See b)	(See b)
HGL (Non-Energy Use)[a]	16.85	(See b)	(See b)	(See b)
Jet Fuel	19.33	5.670	42.0	86.30
Distillate Fuel	19.95	5.825	35.5	86.34
Residual Fuel	21.49	6.287	11.0	85.68
Asphalt and Road Oil	20.62	6.636	5.6	83.47
Lubricants	20.24	6.065	25.6	85.80
Petrochemical Feedstocks	19.37	5.248[c]	67.1[c]	84.11[c]
Aviation Gas	18.87	5.048	69.0	85.00
Kerosene	19.72	5.670	41.4	86.01
Petroleum Coke	27.85	6.024	-	92.28
Special Naphtha	19.86	5.248	51.2	84.76
Petroleum Waxes	19.81	5.537	43.3	85.29
Still Gas	17.51	6.000	-	-
Crude Oil	20.33	5.800	30.5	85.49
Unfinished Oils	20.33	5.825	30.5	85.49
Miscellaneous Products[d]	0.00	0.00	30.5	85.49
Pentanes Plus	18.24	4.620	81.7	83.70
Natural Gasoline	18.24	4.620	81.7	83.70

Note: “-“ Indicates no sample data available.

[a] HGL is a blend of multiple paraffinic and olefinic hydrocarbons: ethane, propane, isobutane, and normal butane, each with their own heat content, density and C content, see Table A-40.

[b] Heat, density, and percent carbon values are provided separately for ethane, and isobutene, butane, ethylene, isobutylene, and butylene.

[c] Parameters presented are for naphthas with a boiling temperature less than 400 degrees Fahrenheit. Petrochemical feedstocks with higher boiling points are assumed to have the same characteristics as distillate fuel.

[d] The miscellaneous products category reported by EIA is assumed to be mostly petroleum refinery sulfur compounds that do not contain carbon (EIA 2019).

Sources: EIA (1994), EIA (2008a), EPA (2009c), EPA (2020b), ICF (2020).

Additional revisions to the Inventory’s C coefficients since 1990 are detailed below.

Jet Fuel

1995 Update

Between 1994 and 1995, the C content coefficient for kerosene-based jet fuel was revised downward from 19.71 MMT C/QBtu to 19.33 MMT C/QBtu. This downward revision was the result of a shift in the sample set used from one collected between 1959 and 1972 and reported on by Martel and Angello in 1977 to one collected by Boeing in 1989 and published by Hadaller and Momenthy in 1990. The downward revision was a result of a decrease in density, as well as slightly lower C shares than in the earlier samples. However, the assumed heat content is unchanged because it is based on an EIA standard and probably yields a downward bias in the revised C content coefficient. The coefficient revised in 1995 was first implemented in the 1990 through 2007 Inventory.

2010 Update

The coefficient was revised again for the 1990 through 2008 Inventory, returning to Martel and Angello and NIPER as the source of the carbon share and density data, respectively, for kerosene-based fuels. This change was made in order to align the coefficients used for this report with the values used in EPA’s *Mandatory Reporting of Greenhouse Gases Rule* (EPA 2009b). The return to the use of the Martel and Angello and NIPER coefficients was deemed more appropriate for the Rule as it was considered a more conservative coefficient given the uncertainty and variability in coefficients across the types of jet fuel in use in the United States.

Hydrocarbon Gas Liquids (HGL)

Summary of Previous Updates

The C content coefficient of HGL is updated annually to reflect changes in the consumption mix of the underlying compounds: ethane; propane; isobutane; normal butane; ethylene; propylene; isobutylene; and butylene. According to EIA, LPG is a subset of HGL, which include the paraffinic compounds: ethane; propane; isobutane; and normal butane. In 1994, EIA included pentanes plus—assumed to have the characteristics of hexane—in the mix of compounds broadly described as LPG. In 1995, EIA removed pentanes plus from this fuel category. Because pentanes plus is relatively rich in C per unit of energy, its removal from the consumption mix lowered the C content coefficient for LPG from 17.26 MMT C/QBtu to 16.99 MMT C/QBtu. In 1998, EIA began separating LPG consumption into two categories: energy use and non-fuel use and providing individual coefficients for each. Because LPG for fuel use typically contains higher proportions of propane than LPG for non-fuel use, the C content coefficient for fuel use was 1.8 to 2.5 percent higher than the coefficient for non-fuel use in previous inventories (see Table A-46).

However, in 2010 the assumptions that underlie the selection of density and heat content data for each pure LPG compound were updated, leading to a significant revision of the assumed properties of ethane. In 2010, the physical characteristics of ethane, which constitutes over 90 percent of LPG consumption for non-fuel uses, were updated to reflect ethane that is in (refrigerated) liquid form. Previously, the share of ethane was included using the density and energy content of gaseous ethane. Table A-47, below, compares the values applied for each of the compounds under the two sets of coefficient calculations, those used in the 1990 through 2007 Inventory and those used in the 1990 through 2008 Inventory to the 1990 through 2018 Inventory. The C share of each pure compound was also updated by using more precise values for each compound's molecular weight.

Due in large part to the revised assumptions for ethane, the weighted C content for non-fuel use was now higher than that of the weighted coefficient for fuel use, which is dominated by the consumption of more dense propane. Under the revised assumptions, each annual weighted coefficient for non-fuel LPG consumption is 1.2 to 1.7 percent higher each year than is that for LPGs consumed for fuel (energy) uses.

Table A-47: Physical Characteristics of Liquefied Petroleum Gases

		1990-2007	2010 Update	1990-2007	2010 Update	1990-2007	2010 Update
Compound	**Chemical Formula**	**Density (bbl / MT)**	**Density (bbl / MT)**	**Energy Content (MMBtu/bbl)**	**Energy Content (MMBtu/bbl)**	**C Content Coefficient (MMT C/QBtu)**	**C Content Coefficient (MMT C/QBtu)**
Ethane	C_2H_6	16.88	11.55	2.916	3.082	16.25	17.16
Propane	C_3H_8	12.44	12.76	3.824	3.836	17.20	16.76
Isobutane	C_4H_{10}	11.20	11.42	4.162	3.974	17.75	17.77
n-butane	C_4H_{10}	10.79	10.98	4.328	4.326	17.72	17.75

Sources: Updated: Densities – CRC Handbook of Chemistry and Physics, 89th Ed. (2008/09); Energy Contents – EPA (2009b). All values are for the compound in liquid form. The density and energy content of ethane are for refrigerated ethane (-89 degrees C). Values for n-butane are for pressurized butane (-25 degrees C). Values in previous editions of this Inventory: Gurthrie (1960).

2020 Update

The coefficients were revised again for the 1990 through 2019 Inventory. This change was made in order to align the coefficients used for this report with the updated heat content values used in EIA's energy data statistics (EIA 2020a; EIA 2020b). EIA (2020a) states, "LPG is a subset of HGL, which include the paraffinic compounds: ethane; propane; isobutane; and normal butane," therefore the Inventory revised the fuel type classification of LPG to HGL to indicate this fuel types includes both paraffinic and olefinic compounds. Furthermore, EIA (2020a) states that HGL consumption in the residential, commercial, and transportation sectors is 100 percent propane. Therefore, a constant, non-weighted propane C content coefficient is applied to HGL consumption in these sectors and is referred to as "LPG – Propane" throughout the Inventory.

The mix of HGL consumed for non-fuel use differs significantly from the mix of HGL that is combusted. C content coefficients for HGL used for fuel use and non-fuel applications were developed based on the consumption mix of the individual compounds reported in U.S. energy statistics (EIA 2020b) for industrial fuel use and industrial non-fuel use across the Inventory timeseries. The C content of each HGL was obtained from EPA (2013) and applied to the fuel use and non-fuel use consumption of each compound. The carbon content coefficient for industrial fuel use and industrial non-fuel use HGL was then calculated through a weighted average that accounts for the consumption proportion for each paraffinic and olefinic compound and their associated C contents (ICF 2020).

Distillate Fuel

2021 Updates

The carbon content of diesel fuel is calculated according to ASTM D3343,[28] *Standard Test Method for the Estimation of Hydrogen Content of Aviation Fuels* using fuel properties inputs from the NAFS for each year and season. This method uses a correlation between the measured fuel distillation range, API gravity, and aromatic content to estimate the hydrogen content (Browning 2020).[29]

Motor Gasoline

Summary of Previous Updates

The C content coefficient for motor gasoline varies annually based on the density of and proportion of additives in a representative sample of motor gasoline examined each year. However, in 1997 EIA began incorporating the effects of the introduction of reformulated gasoline into its estimate of C content coefficients for motor gasoline. This change resulted in a downward step function in C content coefficients for gasoline of approximately 0.3 percent beginning in the 1990 through 1995 Inventory. In 2005 through 2006 reformulated fuels containing ethers began to be phased out nationally. Ethanol was added to gasoline blends as a replacement oxygenate, leading to another shift in gasoline density (see Table A-38), in the list and proportion of constituents that form the blend and in the blended C share based on those constituents.

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[28] ASTM International, ASTM D3343-16, *Standard Test Method for Estimation of Hydrogen Content of Aviation Fuels,* https://www.astm.org/Standards/D3343.htm

[29] As equations are based on assuming hydrocarbon containing fuels only, C % is 100 - H %.

Table A-48: Carbon Content Coefficients for Petroleum Products, 1990-2007 (MMT C/QBtu)

Fuel Type	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Petroleum														
Asphalt and Road Oil	20.62	20.62	20.62	20.62	20.62	20.62	20.62	20.62	20.62	20.62	20.62	20.62	20.62	20.62
Aviation Gasoline	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87
Distillate Fuel Oil	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95
Jet Fuel[a]	19.40	19.34	19.33	19.33	19.33	19.33	19.33	19.33	19.33	19.33	19.33	19.33	19.33	19.33
Kerosene	19.72	19.72	19.72	19.72	19.72	19.72	19.72	19.72	19.72	19.72	19.72	19.72	19.72	19.72
LPG (energy use)[a]	17.21	17.20	17.20	17.18	17.23	17.25	17.20	17.21	17.20	17.21	17.20	17.19	17.19	17.18
LPG (non-energy use)[a]	16.83	16.87	16.86	16.88	16.88	16.84	16.81	16.83	16.82	16.84	16.81	16.81	16.78	16.76
Lubricants	20.24	20.24	20.24	20.24	20.24	20.24	20.24	20.24	20.24	20.24	20.24	20.24	20.24	20.24
Motor Gasoline[a]	19.41	19.38	19.36	19.35	19.33	19.33	19.34	19.34	19.35	19.33	19.33	19.33	19.33	19.33
Residual Fuel	21.49	21.49	21.49	21.49	21.49	21.49	21.49	21.49	21.49	21.49	21.49	21.49	21.49	21.49
Other Petroleum														
AvGas Blend Components	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87
MoGas Blend Components[a]	19.41	19.38	19.36	19.35	19.33	19.33	19.34	19.34	19.35	19.33	19.33	19.33	19.33	19.33
Crude Oil[a]	20.16	20.23	20.25	20.24	20.24	20.19	20.23	20.29	20.30	20.28	20.33	20.33	20.33	20.33
Misc. Products[a]	20.16	20.23	20.25	20.24	20.24	20.19	20.23	20.29	20.30	20.28	20.33	20.33	20.33	20.33
Misc. Products (Terr.)	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
Naphtha (<401 deg. F)	18.14	18.14	18.14	18.14	18.14	18.14	18.14	18.14	18.14	18.14	18.14	18.14	18.14	18.14
Other Oil (>401 deg. F)	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95
Pentanes Plus	18.24	18.24	18.24	18.24	18.24	18.24	18.24	18.24	18.24	18.24	18.24	18.24	18.24	18.24
Petrochemical Feed.	19.37	19.37	19.37	19.37	19.37	19.37	19.37	19.37	19.37	19.37	19.37	19.37	19.37	19.37
Petroleum Coke	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85
Still Gas	17.51	17.51	17.51	17.51	17.51	17.51	17.51	17.51	17.51	17.51	17.51	17.51	17.51	17.51
Special Naphtha	19.86	19.86	19.86	19.86	19.86	19.86	19.86	19.86	19.86	19.86	19.86	19.86	19.86	19.86
Unfinished Oils[a]	20.16	20.23	20.25	20.24	20.24	20.19	20.23	20.29	20.30	20.28	20.33	20.33	20.33	20.33
Waxes	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81
Other Wax and Misc.	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81

[a] C contents vary annually based on changes in fuel composition.

2021 Updates

The annual C content of gasoline over the time series of the Inventory was determined using a combination of two data sources (Browning 2020). The first is the measured properties of both regular and premium gasoline from the Alliance of North American Fuel Survey (NAFS). The second is the prime supplier sales volumes of motor gasoline by type and grade from the EIA.

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2.3. Methodology for Estimating Carbon Emitted from Non-Energy Uses of Fossil Fuels

Carbon (C) storage associated with the non-energy use of fossil fuels was calculated by multiplying each fuel's potential emissions (i.e., each fuel's total C content) by a fuel-specific storage factor, as listed in Table A-49. The remaining C—i.e., that which is not stored—is emitted. This sub-annex explains the methods and data sources employed in developing the storage factors for (1) petrochemical feedstocks (industrial other coal, natural gas for non-fertilizer uses, hydrocarbon gas liquids (HGL), pentanes plus, naphthas, other oils, still gas, special naphtha), (2) asphalt and road oil, (3) lubricants, and (4) waxes. The storage factors[30] for the remaining other (industrial coking coal, petroleum coke, distillate fuel oil, and other petroleum) non-energy fuel uses are either based on values recommended for use by IPCC (2006), or when these were not available, assumptions based on the potential fate of C in the respective non-energy use (NEU) products.

Table A-49: Fuel Types and Percent of C Stored for Non-Energy Uses

Sector/Fuel Type	Storage Factor (%)
Industry	
Industrial Coking Coal[a]	10%
Industrial Other Coal[b]	62%
Natural Gas to Chemical Plants[b]	62%
Asphalt & Road Oil	100%
HGL[b]	62%
Lubricants	9%
Pentanes Plus[b]	62%
Naphtha (<401 deg. F)[b]	62%
Other Oil (>401 deg. F)[b]	62%
Still Gas[b]	62%
Petroleum Coke[c]	30%
Special Naphtha[b]	62%
Distillate Fuel Oil	50%
Waxes	58%
Miscellaneous Products[d]	0%
Transportation	
Lubricants	9%
U.S. Territories	
Lubricants	9%
Other Petroleum (Misc. Prod.)	10%

[a] Includes processes for which specific coking coal consumption and emission factor data are not available. Consumption of coking coal for production of iron and steel is covered in the Industrial Processes and Product Use chapter.

[b] The storage factor listed is the value for 2019. As described in this annex, the factor varies over time.

[c] Assumes petroleum coke consumption is for pigments. Consumption of petroleum coke for production of primary aluminum anodes, electric arc furnace anodes, titanium dioxide, ammonia, urea, and ferroalloys is covered in the Industrial Processes and Product Use chapter.

[d] The miscellaneous products category reported by EIA is assumed to be mostly petroleum refinery sulfur compounds that do not contain carbon (EIA 2019).

The following sections describe the non-energy uses in greater detail, outlining the methods employed and data used in estimating each storage factor. Several of the fuel types tracked by EIA are used in organic chemical synthesis and in other manufacturing processes and are referred to collectively as "petrochemical feedstocks." Because the methods and data used to analyze them overlap, they are handled as a group and are discussed first. Discussions of the storage factors for asphalt and road oil, lubricants, waxes, and other products follow.

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[30] Throughout this section, references to "storage factors" represent the proportion of carbon stored.

Petrochemical Feedstocks

Petrochemical feedstocks—industrial other coal, natural gas for non-fertilizer uses,[31] HGL, pentanes plus, naphthas, other oils, still gas, special naphtha—are used in the manufacture of a wide variety of man-made chemicals and products. Plastics, rubber, synthetic fibers, solvents, paints, fertilizers, pharmaceuticals, and food additives are just a few of the derivatives of these fuel types. Chemically speaking, these fuels are diverse, ranging from simple natural gas (i.e., predominantly CH_4) to heavier, more complex naphthas and other oils.[32]

After adjustments for (1) use in industrial processes and (2) net exports, these eight fuel categories constituted approximately 261.1 MMT CO_2 Eq., or 73 percent, of the 357.5 MMT CO_2 Eq. of non-energy fuel consumption in 2019. For 2019, the storage factor for the eight fuel categories was 62 percent. In other words, of the net consumption, 62 percent was destined for long-term storage in products—including products subsequently combusted for waste disposal—while the remaining 38 percent was emitted to the atmosphere directly as CO_2 (e.g., through combustion of industrial by-products) or indirectly as CO_2 precursors (e.g., through evaporative product use). The indirect emissions include a variety of organic gases such as volatile organic compounds (VOCs) and carbon monoxide (CO), which eventually oxidize into CO_2 in the atmosphere. The derivation of the storage factor is described in the following sections.

Methodology and Data Sources

The petrochemical feedstocks storage factor is equal to the ratio of C stored in the final products to total C content for the non-energy fossil fuel feedstocks used in industrial processes, after adjusting for net exports of feedstocks. One aggregate storage factor was calculated to represent all eight fuel feedstock types. The feedstocks were grouped because of the overlap of their derivative products. Due to the many reaction pathways involved in producing petrochemical products (or wastes), it becomes extraordinarily complex to link individual products (or wastes) to their parent fuel feedstocks.

Import and export data for feedstocks were obtained from the Energy Information Administration (EIA) for the major categories of petrochemical feedstocks. EIA's *Petroleum Supply Annual* publication tracks imports and exports of petrochemical feedstocks, including HGL,[33] and naphthas (i.e., most of the large volume primary chemicals produced by petroleum refineries). These imports and exports are already factored into the U.S. fuel consumption statistics. However, EIA does not track imports and exports of chemical intermediates and products produced by the chemical industry (e.g., xylenes, vinyl chloride), which are derived from the primary chemicals produced by the refineries. These products represent very large flows of C derived from fossil fuels (i.e., fossil C), so estimates of net flows not already considered in EIA's dataset were developed for the entire time series from 1990 to 2019.

The approach to estimate imports and exports involves three steps, listed here and then described in more detail below:

Step 1. Identify commodities derived from petrochemical feedstocks, and calculate net import/export for each.

Step 2. Estimate the C content for each commodity.

Step 3. Sum the net C imports/exports across all commodities.

Step 1 relies heavily on information provided by the National Petrochemical and Refiners Association (NPRA) and U.S. Bureau of the Census (BoC) trade statistics published by the U.S. International Trade Commission (USITC). NPRA provided a spreadsheet of the ten-digit BoC Harmonized Tariff Schedule (HTS) Commodity Codes used to compile import-

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[31] Natural gas used as a petrochemical feedstock includes use in production of methanol. The storage factor developed for petrochemical feedstocks includes emissions from the use of products. Therefore, it is assumed that emissions from the combustion of methanol used in biodiesel are captured here and not reported as part of biodiesel combustion emissions.

[32] Naphthas are compounds distilled from petroleum containing 4 to 12 carbon atoms per molecule and having a boiling point less than 401 degrees Fahrenheit. "Other oils" are distillates containing 12 to 25 carbon atoms per molecule and having a boiling point greater than 401 degrees Fahrenheit.

[33] HGL (formerly referred to as liquefied petroleum gas, or LPG) are hydrocarbons that occur as gases at atmospheric pressure and as liquids under higher pressures. HGLs include paraffins, such as ethane, propane, butanes, and pentanes plus, and HGLs include olefins, such as ethylene, propylene, and butylene. Adjustments were made in the current Inventory report to HGL activity data, carbon content coefficients, and heat contents HGL.

export data for periodic reports issued to NPRA's membership on trade issues. Additional feedstock commodities were identified by HTS code in the BoC data system and included in the net import/export analysis.

One of the difficulties in analyzing trade data is that a large portion of the outputs from the refining industry are fuels and fuel components, and it was difficult to segregate these from the outputs used for non-energy uses. The NPRA-supplied codes identify fuels and fuel components, thus providing a sound basis for isolating net imports/exports of petrochemical feedstocks. Although MTBE and related ether imports are included in the published NPRA data, these commodities are not included in the total net imports/exports calculated here, because it is assumed that they are fuel additives and do not contribute to domestic petrochemical feedstocks. Net exports of MTBE and related ethers are also not included in the totals, as these commodities are considered to be refinery products that are already accounted for in the EIA data. Imports and exports of commodities for which production and consumption data are provided by EIA (e.g., butane, ethylene, and liquefied petroleum gases) are also not included in the totals, to avoid double-counting.

Another difficulty is that one must be careful to assure that there is not double-counting of imports and exports in the data set. Other parts of the mass balance (described later) provide information on C flows, in some cases based on production data and in other cases based on consumption data. Production data relates only to production within the country; consumption data incorporates information on imports and exports as well as production. Because many commodities are emissive in their use, but not necessarily their production, consumption data is appropriately used in calculations for emissive fates. For purposes of developing an overall mass balance on U.S. non-energy uses of C, for those materials that are non-emissive (e.g., plastics), production data is most applicable. And for purposes of adjusting the mass balance to incorporate C flows associated with imports and exports, it was necessary to carefully review whether or not the mass balance already incorporated cross-boundary flows (through the use of consumption data), and to adjust the import/export balance accordingly.

The BoC trade statistics are publicly available[34] and cover a complete time series from 1990 to 2019. These statistics include information on imports and exports of thousands of commodities. After collecting information on annual flows of the more than 100 commodities identified by NPRA, Step 2 involves calculating the C content for each commodity from its chemical formula. In cases where the imports and exports were expressed in units of volume, rather than mass, they were converted to mass based on the commodities' densities.

Step 3 involves summing the net C imports/exports across all commodities. The results of this step are shown in Table A-50. As shown in the table, the United States has been a net exporter of chemical intermediates and products throughout the 1990 to 2019 period.

Table A-50: Net Exports of Petrochemical Feedstocks, 1990–2019 (MMT CO_2 Eq.)

	1990		2005		2010		2015	2016	2017	2018	2019
Net Exports	12.0		6.5		7.3		5.5	12.7	13.9	17.1	21.0

After adjusting for imports and exports, the C budget is adjusted for the quantity of C that is used in the Industrial Processes and Product Use sector of the Inventory. Fossil fuels used for non-energy purposes in industrial processes—and for which C emissions and storage have been characterized through mass balance calculations and/or emission factors that directly link the non-energy use fossil fuel raw material and the industrial process product—are not included in the non-energy use sector. These industrial processes (and their non-energy use fossil fuel raw materials) include iron and steel (coal coke), primary aluminum (petroleum coke), titanium oxide (petroleum coke), ferroalloys (petroleum coke), carbon black (petroleum coke and other oils), silicon carbide (petroleum coke), and ammonia and urea (petroleum coke and natural gas).

For each year of the Inventory, the total C content of non-energy uses was calculated by starting with the EIA estimate of non-energy use, and reducing it by the adjustment factor for net exports (see Table A-50) and non-energy use reported in the Industrial Processes and Product Use (IPPU) sector to yield net domestic fuel consumption for non-energy. The balance was apportioned to either stored C or emissive C, based on a storage factor.

The overall storage factor for the feedstocks was determined by developing a mass balance on the C in feedstocks, and characterizing products, uses, and environmental releases as resulting in either storage or emissions. The total C in the system was estimated by multiplying net domestic consumption for non-energy by the C content of each of the feedstocks (i.e., industrial other coal, natural gas for non-fertilizer uses, HGL, pentanes plus, naphthas, other oils, still

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[34] See the U.S. International Trade Commission (USITC) Trade Dataweb at <http://dataweb.usitc.gov/>.

gas, special naphtha). Carbon content values for the fuel feedstocks are discussed in the Estimating Emissions from Fossil Fuel Combustion and Estimating the Carbon Content from Fossil Fuel Combustion Annexes.

Next, C pools and releases in a variety of industrial releases, energy recovery processes, and products were characterized. The C fate categories are plastics, energy recovery, synthetic rubber, synthetic fibers, organic solvents, C black, detergents and personal cleansers, industrial non-methane volatile organic compound (NMVOC) emissions, hazardous waste incineration, industrial toxic chemical (i.e., TRI) releases, pesticides, food additives, antifreeze and deicers (glycols), and silicones.[35]

The C in each product or waste produced was categorized as either stored or emitted. The aggregate storage factor is the C-weighted average of storage across fuel types. As discussed later in the section on uncertainty, the sum of stored C and emitted C (i.e., the outputs of the system) exceeded total C consumption (i.e., the inputs to the system) for some years in the time series. To address this mass imbalance, the storage factor was calculated as C storage divided by total C outputs (rather than C storage divided by C inputs).

Note that the system boundaries for the storage factor do not encompass the entire life-cycle of fossil-based C consumed in the United States insofar as emissions of CO_2 from waste combustion are accounted for separately in the Inventory and are discussed in the Incineration of Waste section of the Energy chapter.

The following sections provide details on the calculation steps, assumptions, and data sources employed in estimating and classifying the C in each product and waste shown in Table A-51. Summing the C stored and dividing it by total C outputs yields the overall storage factor, as shown in the following equation for 2019:

Overall Storage Factor = C Stored / (C Stored + C Emitted + C Unaccounted for) =

161.8 MMT CO_2 Eq. / (161.8 + 63.0 + 36.3) MMT CO_2 Eq. = 62%

Table A-51: C Stored and Emitted by Products from Feedstocks in 2019 (MMT CO_2 Eq.)

Product/Waste Type	C Stored (MMT CO_2 Eq.)	C Emitted (MMT CO_2 Eq.)
Industrial Releases	**0.1**	**5.7**
TRI Releases	0.1	1.0
Industrial VOCs	NA	3.4
Non-combustion CO	NA	0.5
Hazardous Waste Incineration	NA	0.9
Energy Recovery	**NA**	**44.4**
Products	**161.7**	**12.8**
Plastics	140.3	NA
Synthetic Rubber	12.9	NA
Antifreeze and Deicers	NA	1.0
Abraded Tire Rubber	NA	0.2
Food Additives	NA	1.1
Silicones	0.5	NA
Synthetic Fiber	7.8	NA
Pesticides	0.2	0.3
Soaps, Shampoos, Detergents	NA	4.7
Solvent VOCs	NA	5.6
Total	**161.8**	**63.0**

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

The C unaccounted for is the difference between the C accounted for (discussed below) and the total C in the Total U.S. Petrochemical consumption, which are the potential carbon emissions from all energy consumption in Non-Energy Use.

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[35] For the most part, the releases covered by the U.S. Toxic Release Inventory (TRI) represent air emissions or water discharges associated with production facilities. Similarly, VOC emissions are generally associated with production facilities. These emissions could have been accounted for as part of the Waste chapter, but because they are not necessarily associated with waste management, they were included here. Toxic releases are not a "product" category, but they are referred to as such for ease of discussion.

The three categories of C accounted for in the table are industrial releases, energy recovery, and products. Each is discussed below.

Industrial Releases

Industrial releases include toxic chemicals reported through the Toxics Release Inventory (TRI), industrial emissions of volatile organic compounds (VOCs), CO emissions (other than those related to fuel combustion), and emissions from hazardous waste incineration.

TRI Releases

Fossil-derived C is found in many toxic substances released by industrial facilities. The TRI, maintained by EPA, tracks these releases by chemical and environmental release medium (i.e., land, air, or water) on a biennial basis (EPA 2000b). By examining the C contents and receiving media for the top 35 toxic chemicals released, which account for 90 percent of the total mass of chemicals, the quantity of C stored and emitted in the form of toxic releases can be estimated.

The TRI specifies releases by chemical, so C contents were assigned to each chemical based on molecular formula. The TRI also classifies releases by disposal location as either off-site or on-site. The on-site releases are further subdivided into air emissions, surface water discharges, underground injection, and releases to land; the latter is further broken down to disposal in a RCRA Subtitle C (i.e., hazardous waste) landfill or to "Other On-Site Land Disposal."[36] The C released in each disposal location is provided in Table A-52.

Each on-site classification was assigned a storage factor. A 100 percent storage factor was applied to disposition of C to underground injection and to disposal to RCRA-permitted landfills, while the other disposition categories were assumed to result in an ultimate fate of emission as CO_2 (i.e., a storage factor of zero was applied to these categories). The release allocation is not reported for off-site releases; therefore, the approach was to develop a C-weighted average storage factor for the on-site C and apply it to the off-site releases.

For the remaining 10 percent of the TRI releases, the weights of all chemicals were added and an average C content value, based upon the top 35 chemicals' C contents, was applied. The storage and emission allocation for the remaining 10 percent of the TRI releases was carried out in the same fashion as for the 35 major chemicals.

Data on TRI releases for the full 1990 through 2019 time series were not readily available. Since this category is small (less than 1 MMT C emitted and stored), the 1998 value was applied for the entire time series.

Table A-52: 1998 TRI Releases by Disposal Location (kt CO_2 Eq.)

Disposal Location	Carbon Stored (kt CO_2 Eq.)	Carbon Emitted (kt CO_2 Eq.)
Air Emissions	NA	924
Surface Water Discharges	NA	6.7
Underground Injection	89.4	NA
RCRA Subtitle C Landfill Disposal	1.4	NA
Other On-Site Land Releases	NA	15.9
Off-site Releases	6.4	36
Total	**97.2**	**982.6**

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

Volatile Organic Compound Emissions from Industrial Processes and Solvent Evaporation Emissions

Data on annual non-methane volatile organic compound (NMVOC) emissions were obtained (EPA 2020) and disaggregated based on EPA (2003), which has been published on the National Emission Inventory (NEI) Air Pollutant Emission Trends web site. The 1990 through 2019 Trends data include information on NMVOC emissions by end-use

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[36] Only the top nine chemicals had their land releases separated into RCRA Landfills and Other Land Disposal. For the remaining chemicals, it was assumed that the ratio of disposal in these two categories was equal to the carbon-weighted average of the land disposal fate of the top nine chemicals (i.e., 8 percent attributed to RCRA Landfills and 92 percent in the "Other" category).

category; some of these fall into the heading of "industrial releases" in Table A-51 above, and others are related to "product use;" for ease of discussion, both are covered here. The end-use categories that represent "Industrial NMVOC Emissions" include some chemical and allied products, certain petroleum related industries, and other industrial processes. NMVOC emissions from solvent utilization (product use) were considered to be a result of non-energy use of petrochemical feedstocks. These categories were used to distinguish non-energy uses from energy uses; other categories where VOCs could be emitted due to combustion of fossil fuels were excluded to avoid double counting.

Because solvent evaporation and industrial NMVOC emission data are provided in tons of total NMVOCs, assumptions were made concerning the average C content of the NMVOCs for each category of emissions. The assumptions for calculating the C fraction of industrial and solvent utilization emissions were made separately and differ significantly. For industrial NMVOC emissions, a C content of 85 percent was assumed. This value was chosen to reflect the C content of an average volatile organic compound based on the list of the most abundant NMVOCs provided in the Trends Report. The list contains only pure hydrocarbons, including saturated alkanes (C contents ranging from 80 to 85 percent based upon C number), alkenes (C contents approximately 85 percent), and some aromatics (C contents approximately 90 percent, depending upon substitution).

An EPA solvent evaporation emissions dataset (Tooly 2001) was used to estimate the C content of solvent emissions. The dataset identifies solvent emissions by compound or compound category for six different solvent end-use categories: degreasing, graphic arts, dry cleaning, surface coating, other industrial processes, and non-industrial processes. The percent C of each compound identified in the dataset was calculated based on the molecular formula of the individual compound (e.g., the C content of methylene chloride is 14 percent; the C content of toluene is 91 percent). For solvent emissions that are identified in the EPA dataset only by chemical category (e.g., butanediol derivatives) a single individual compound was selected to represent each category, and the C content of the category was estimated based on the C content of the representative compound. The overall C content of the solvent evaporation emissions for 1998, estimated to be 56 percent, is assumed to be constant across the entire time series.

The results of the industrial and solvent NMVOC emissions analysis are provided in Table A-53 for 1990 through 2019. Industrial NMVOC emissions in 2019 were 3.4 MMT CO_2 Eq. and solvent evaporation emissions in 2019 were 5.6 MMT CO_2 Eq.

Table A-53: Industrial and Solvent NMVOC Emissions

	1990	1995	2000	2005	2015	2016	2017	2018	2019
Industrial NMVOCs[a]									
NMVOCs ('000 Short Tons)	1,279	1,358	802	825	1,349	1,277	1,205	1,205	1,205
Carbon Content (%)	85%	85%	85%	85%	85%	85%	85%	85%	85%
Carbon Emitted (MMT CO_2 Eq.)	3.6	3.8	2.3	2.3	3.8	3.6	3.4	3.4	3.4
Solvent Evaporation[b]									
Solvents ('000 Short Tons)	5,750	6,183	4,832	4,245	3,025	2,999	2,972	2,972	2,972
Carbon Content (%)	56%	56%	56%	56%	56%	56%	56%	56%	56%
Carbon Emitted (MMT CO_2 Eq.)	10.8	11.6	9.0	7.9	5.7	5.6	5.6	5.6	5.6

[a] Includes emissions from chemical and allied products, petroleum and related industries, and other industrial processes categories.

[b] Includes solvent usage and solvent evaporation emissions from degreasing, graphic arts, dry cleaning, surface coating, other industrial processes, and non-industrial processes.

Non-Combustion Carbon Monoxide Emissions

Carbon monoxide (CO) emissions data were also obtained from the NEI data (EPA 2020) and disaggregated based on EPA (2003). There are three categories of CO emissions in the report that are classified as process-related emissions not related to fuel combustion. These include chemical and allied products manufacturing, metals processing, and other industrial processes. Some of these CO emissions are accounted for in the Industrial Processes and Product Use section of this report and are therefore not accounted for in this section. These include total C emissions from the primary aluminum, titanium dioxide, iron and steel, and ferroalloys production processes. The total C (CO and CO_2) emissions from oil and gas production, petroleum refining, and asphalt manufacturing are also accounted for elsewhere in this Inventory. Biogenic emissions (e.g., pulp and paper process emissions) are accounted for in the Land Use, Land-

Use Change and Forestry chapter and excluded from calculation of CO emissions in this section. Those CO emissions that are not accounted for elsewhere are considered to be by-products of non-fuel use of feedstocks and are thus included in the calculation of the petrochemical feedstocks storage factor. Table A-54 lists the CO emissions that remain after taking into account the exclusions listed above.

Table A-54: Non-Combustion Carbon Monoxide Emissions

	1990	1995	2000	2005	2015	2016	2017	2018	2019
CO Emissions (‘000 Short Tons)	489	481	623	461	389	358	327	327	327
Carbon Emitted (MMT CO_2 Eq.)	0.7	0.7	0.9	0.7	0.6	0.5	0.5	0.5	0.5

Note: Includes emissions from chemical and allied products, petroleum and related industries, metals processing, and other industrial processes categories.

Hazardous Waste Incineration

Hazardous wastes are defined by the EPA under the Resource Conservation and Recovery Act (RCRA).[37] Industrial wastes, such as rejected products, spent reagents, reaction by-products, and sludges from wastewater or air pollution control, are federally regulated as hazardous wastes if they are found to be ignitable, corrosive, reactive, or toxic according to standardized tests or studies conducted by EPA.

Hazardous wastes must be treated prior to disposal according to the federal regulations established under the authority of RCRA. Combustion is one of the most common techniques for hazardous waste treatment, particularly for those wastes that are primarily organic in composition or contain primarily organic contaminants. Generally speaking, combustion devices fall into two categories: incinerators that burn waste solely for the purpose of waste management, and boilers and industrial furnaces (BIFs) that burn waste in part to recover energy from the waste. More than half of the hazardous waste combusted in the United States is burned in BIFs; because these processes are included in the energy recovery calculations described below, they are not included as part of hazardous waste incineration.

EPA’s Office of Solid Waste requires biennial reporting of hazardous waste management activities, and these reports provide estimates of the amount of hazardous waste burned for incineration or energy recovery. EPA stores this information in its Resource Conservation and Recovery Act (RCRA) Information system (EPA 2013a), formerly reported in its Biennial Reporting System (BRS) database (EPA 2000a; 2009; 2015a; 2016a; 2018; 2021). Combusted hazardous wastes are identified based on EPA-defined management system types M041 through M049 (incineration). Combusted quantities are grouped into four representative waste form categories based on the form codes reported in the BRS: aqueous liquids, organic liquids and sludges, organic solids, and inorganic solids. To relate hazardous waste quantities to C emissions, “fuel equivalent” factors were derived for hazardous waste by assuming that the hazardous wastes are simple mixtures of a common fuel, water, and noncombustible ash. For liquids and sludges, crude oil is used as the fuel equivalent and coal is used to represent solids.

Fuel equivalent factors were multiplied by the tons of waste incinerated to obtain the tons of fuel equivalent. Multiplying the tons of fuel equivalent by the C content factors (discussed in the Estimating the Carbon Content from Fossil Fuel Combustion Annex) yields tons of C emitted. Implied C content is calculated by dividing the tons of C emitted by the associated tons of waste incinerated.

Waste quantity data for hazardous wastes were obtained from EPA’s RCRA Information/BRS database for reporting years 1989, 1991, 1993, 1995, 1997, 1999, 2001, 2003, 2005, 2007, 2009, 2011, 2013, 2015, 2017, 2019 (EPA 2000a; 2009; 2013a; 2015a; 2016a; 2018; 2021). Combusted waste quantities were obtained from Form GM (Generation and Management) for wastes burned on site and Form WR (Wastes Received) for waste received from off-site for combustion. For each of the waste types, assumptions were developed on average waste composition (see Table A-55). Regulations require incinerators to achieve at least 99.99 percent destruction of organics; this formed the basis for assuming the fraction of C oxidized. Emissions from hazardous waste incineration in 2019 were 0.9 MMT CO_2 Eq. Table A-56 lists the CO_2 emissions from hazardous waste incineration.

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[37] [42 U.S.C. §6924, SDWA §3004]

Table A-55: Assumed Composition of Combusted Hazardous Waste by Weight (Percent)

Waste Type	Water (%)	Noncombustibles (%)	Fuel Equivalent (%)
Aqueous Waste	90	5	5
Organic Liquids and Sludges	40	20	40
Organic Solids	20	40	40
Inorganic Solids	20	70	10

Table A-56: CO_2 Emitted from Hazardous Waste Incineration (MMT CO_2 Eq.)

	1990	1995	2000	2005	2015	2016	2017	2018	2019
CO_2 Emissions	1.1	1.7	1.4	1.5	0.9	0.9	0.9	0.9	0.9

Energy Recovery

The amount of feedstocks combusted for energy recovery was estimated from data included in EIA's Manufacturers Energy Consumption Survey (MECS) for 1991, 1994, 1998, 2002, 2006, 2010, 2014, and 2018 (EIA 1994; 1997; 2001; 2005; 2010; 2013b; 2017; 2021). Some fraction of the fossil C exiting refineries and designated for use for feedstock purposes actually ends up being combusted for energy recovery (despite the designation of feedstocks as a "non-energy" use) because the chemical reactions in which fuel feedstocks are used are not 100 percent efficient. These chemical reactions may generate unreacted raw material feedstocks or generate by-products that have a high energy content. The chemical industry and many downstream industries are energy-intensive and often have boilers or other energy recovery units on-site, and thus these unreacted feedstocks or by-products are often combusted for energy recovery. Also, as noted above in the section on hazardous waste incineration, regulations provide a strong incentive—and in some cases require—burning of organic wastes generated from chemical production processes.

Information available from the MECS include data on the consumption for energy recovery of "other" fuels in the petroleum and coal products, chemicals, primary metals, nonmetallic minerals, and other manufacturing sectors. These "other" fuels include refinery still gas; waste gas; waste oils, tars, and related materials; petroleum coke, coke oven and blast furnace gases; scrap tires; liquor or black liquor; woodchips and bark; and other uncharacterized fuels. Fuel use of petroleum coke is included separately in the fuel use data provided annually by EIA, and energy recovery of coke oven gas and blast furnace gas (i.e., by-products of the iron and steel production process) is addressed in the Iron and Steel production section in the Industrial Processes and Product Use chapter. Consumption of refinery still gas in the refinery sector is also included separately in the fuel use data from EIA. The combustion of scrap tires in cement kilns, lime kilns, and electric arc furnaces is accounted for in the Waste Incineration chapter; data from the Rubber Manufacturers Association (RMA 2009a) were used to subtract out energy recovery from scrap tires in these industries. Consumption of net steam, assumed to be generated from fossil fuel combustion, is also included separately in the fuel use data from EIA. Therefore, these categories of "other" fuels are addressed elsewhere in the Inventory and not considered as part of the petrochemical feedstocks energy recovery analysis. Liquor or black liquor and woodchips and bark are assumed to be biogenic fuels, in accordance with IPCC (2006), and therefore are not included in the Inventory. The remaining categories of fuels, including waste gas; waste oils, tars, and related materials; and other uncharacterized fuels are assumed to be petrochemical feedstocks burned for energy recovery (see Table A-57). The conversion factors listed in Annex 2.1 were used to convert the Btu values for each fuel feedstock to MMT CO_2. Petrochemical feedstocks combusted for energy recovery corresponded to 42.5 MMT CO_2 Eq. in 1991, 35.1 MMT CO_2 Eq. in 1994, 58.0 MMT CO_2 Eq. in 1998, 70.6 MMT CO_2 Eq. in 2002, 74.7 MMT CO_2 Eq. in 2006, 41.3 MMT CO_2 Eq. in 2010, 45.6 MMT CO_2 Eq. in 2014, and 44.4 MT CO_2 Eq in 2018. Values for petrochemical feedstocks burned for energy recovery for years between 1991 and 1994, between 1994 and 1998, between 1998 and 2002, between 2002 and 2006, between 2007 and 2010, between 2011 and 2013, and between 2015 and 2017 have been estimated by linear interpolation. The value for 1990 is assumed to be the same as the value for 1991, and the value 2019 is assumed to be the same as the value for 2018 (Table A-58).

Table A-57: Summary of 2018 MECS Data for Other Fuels Used in Manufacturing/Energy Recovery (Trillion Btu)

Subsector and Industry	NAICS CODE	Waste Gas[a]	Waste Oils/Tars[b]	Refinery Still Gas[c]	Net Steam[d]	Other Fuels[e]
Printing and Related Support	323	0	0	0	0	0
Petroleum and Coal Products	324	0	2	1,394	191	76
Chemicals	325	402	6	0	310	116
Plastics and Rubber Products	326	0	0	0	0	0
Nonmetallic Mineral Products	327	0	9	0	0	18
Primary Metals	331	3	0	0	10	3
Fabricated Metal Products	332	0	0	0	0	2
Machinery	333	0	0	0	0	1
Computer and Electronic Products	334	0	0	0	0	0
Electrical Equip., Appliances, Components	335	0	0	0	0	0
Transportation Equipment	336	1	0	0	1	5
Furniture and Related Products	337	0	0	0	0	5
Miscellaneous	339	0	0	0	0	1
Total (Trillion Btu)		**406**	**17**	**1,394**	**511**	**227**
Average C Content (MMT/QBtu)		18.14	20.62	17.51	0	19.37
Fraction Oxidized		1	1	1	0	1
Total C (MMT)		**7.36**	**0.35**	**24.41**	**0.00**	**4.40**
Total C (MMT) (ex. still gas from refining)		**7.36**	**0.35**	**0.00**	**0.00**	**4.40**

NA (Not Applicable)

[a] C content: Waste Gas is assumed to be same as naphtha <401 deg. F.

[b] C content: Waste Oils/Tars is assumed to be same as asphalt/road oil.

[c] Refinery "still gas" fuel consumption is reported elsewhere in the Inventory and is excluded from the total C content estimate.

[d] Net steam fuel consumption is reported elsewhere in the Inventory and is excluded from the total C content estimate.

[e] C content: "Other" is assumed to be the same as petrochemical feedstocks.

Table A-58: Carbon Emitted from Fuels Burned for Energy Recovery (MMT CO_2 Eq.)

	1990	1995	2000	2005	2015	2016	2017	2018	2019
C Emissions	42.5	40.8	64.3	73.7	45.3	45.0	44.7	44.4	44.4

Products

More C is found in products than in industrial releases or energy recovery. The principal types of products are plastics; synthetic rubber; synthetic fiber; C black; pesticides; soaps, detergents, and cleansers; food additives; antifreeze and deicers (glycols); silicones; and solvents. Solvent evaporation was discussed previously along with industrial releases of NMVOCs; the other product types are discussed below.

Plastics

Data on annual production of plastics through 2005 were taken from the American Plastics Council (APC), as published in *Chemical & Engineering News* and on the APC and Society of Plastics Industry (SPI) websites, and through direct communication with the APC (APC 2000, 2001, 2003 through 2006; SPI 2000; Eldredge-Roebuck 2000). Data for 2006 through 2019 were taken directly or derived from the American Chemistry Council (ACC 2007 through 2020b supplemented by Vallianos 2011, 2012, 2013, 2014, 2015, 2016, 2017, 2018, 2019, 2020). In 2009, the American Chemistry Council consolidated the resin categories for which it reports plastics production. Production numbers in the original categories were provided via personal correspondence for 2009, 2011, 2012, 2013, 2014, 2015, 2016, 2017, 2018, and 2019 (Vallianos 2011; 2012; 2013; 2014; 2015; 2016; 2017; 2018; 2019; 2020). Production figures for the consolidated resin categories in 2010 were linearly interpolated from 2009 and 2011 data. Production was organized by resin type (see Table A-59) and by year.

Several of the resin categories included production from Canada and/or Mexico, in addition to the U.S. values for part of the time series. The production data for the affected resins and years were corrected using an economic adjustment factor, based on the percent of North American production value in this industry sector accounted for by the United States (Chemistry Industry Association of Canada 2020, Bank of Canada 2020). A C content was then assigned for each resin. These C contents were based on molecular formulae and are listed in Table A-60 and Table A-61. In cases where the resin type is generic, referring to a group of chemicals and not a single polymer (e.g., phenolic resins, other styrenic resins), a representative compound was chosen. For other resins, a weighted C content of 75 percent was assumed (i.e., it was assumed that these resins had the same content as those for which a representative compound could be assigned).

There were no emissive uses of plastics identified, so 100 percent of the C was considered stored in products. As noted in the chapter, an estimate of emissions related to the combustion of these plastics in the municipal solid waste stream can be found in the Incineration of Waste section of the Energy chapter; those emissions are not incorporated in the mass balance for feedstocks (described in this annex) to avoid double-counting.

Table A-59: 2019 Plastic Resin Production (MMT dry weight) and C Stored (MMT CO_2 Eq.)

Resin Type	2019 Production[a] (MMT dry weight)	Carbon Stored (MMT CO_2 Eq.)
Epoxy	0.2	0.7
Polyester	0.6	1.5
Urea	1.2	1.5
Melamine	0.1	0.1
Phenolic	1.6	4.5
Low-Density Polyethylene (LDPE)	3.2	10.1
Linear Low-Density Polyethylene (LLDPE)	8.6	27.1
High Density Polyethylene (HDPE)	9.4	29.4
Polypropylene (PP)	6.7	21.0
Acrylonitrile-butadiene-styrene (ABS)	0.5	1.6
Other Styrenics[b]	0.5	1.7
Polystyrene (PS)	1.7	5.6
Nylon	0.4	1.0
Polyvinyl chloride (PVC)[c]	6.7	9.5
Thermoplastic Polyester	3.1	7.2
All Other (including Polyester (unsaturated))	6.5	17.9
Total	**51.1**	**140.3**

Note: Totals may not sum due to independent rounding.

[a] Production estimates provided by the American Chemistry Council include Canadian production for Urea, Melamine, Phenolic, LDPE, LLDPE, HDPE, PP, ABS, SAN, Other Styrenics, PS, Nylon, PVC, and Thermoplastic Polyester, and Mexican production for PP, ABS, SAN, Other Styrenics, Nylon, and Thermoplastic Polyester. Values have been adjusted to account just for U.S. production.

[b] Includes Styrene-acrylonitrile (SAN).

[c] Includes copolymers.

Table A-60: Assigned C Contents of Plastic Resins (% by weight)

Resin Type	C Content	Source of C Content Assumption
Epoxy	76%	Typical epoxy resin made from epichlorhydrin and bisphenol A
Polyester (Unsaturated)	63%	Poly (ethylene terephthalate) (PET)
Urea	34%	50% carbamal, 50% N-(hydroxymethyl) urea[a]
Melamine	29%	Trimethylol melamine[a]
Phenolic	77%	Phenol
Low-Density Polyethylene (LDPE)	86%	Polyethylene
Linear Low-Density Polyethylene (LLDPE)	86%	Polyethylene
High Density Polyethylene (HDPE)	86%	Polyethylene
Polypropylene (PP)	86%	Polypropylene
Acrylonitrile-Butadiene-Styrene (ABS)	85%	50% styrene, 25% acrylonitrile, 25% butadiene
Styrene-Acrylonitrile (SAN)	80%	50% styrene, 50% acrylonitrile
Other Styrenics	92%	Polystyrene
Polystyrene (PS)	92%	Polystyrene
Nylon	65%	Average of nylon resins (see Table A-)
Polyvinyl Chloride (PVC)	38%	Polyvinyl chloride
Thermoplastic Polyester	63%	Polyethylene terephthalate
All Other	75%	Weighted average of other resin production

[a] Does not include alcoholic hydrogens.

Table A-61: Major Nylon Resins and their C Contents (% by weight)

Resin	C Content
Nylon 6	64%
Nylon 6,6	64%
Nylon 4	52%
Nylon 6,10	68%
Nylon 6,11	69%
Nylon 6,12	70%
Nylon 11	72%

Synthetic Rubber

Data on synthetic rubber in tires were derived from data on the scrap tire market and the composition of scrap tires from the Rubber Manufacturers' Association (RMA). The market information is presented in the report *2017 U.S. Scrap Tire Management Summary* (RMA 2018), while the tire composition information is from the "Scrap Tires, Facts and Figures" section of the organization's website (RMA 2009). Data on synthetic rubber in other products (durable goods, nondurable goods, and containers and packaging) were obtained from EPA's *Municipal Solid Waste in the United States* reports (1996 through 2003a, 2005, 2007b, 2008, 2009a, 2011a, 2013b, 2014, 2016b, 2019) and detailed unpublished backup data for some years not shown in the *Characterization of Municipal Solid Waste in the United States* reports (Schneider 2007). The abraded rubber from scrap passenger tires was assumed to be 2.5 pounds per scrap tire, while the abraded rubber from scrap commercial tires was assumed to be 10 pounds per scrap tire. Data on abraded rubber weight were obtained by calculating the average weight difference between new and scrap tires (RMA 2018). Import and export data were obtained from the published by the U.S. International Trade Commission (U.S. International Trade Commission 1990 through 2019).

A C content for synthetic rubber (90 percent for tire synthetic rubber and 85 percent for non-tire synthetic rubber) was assigned based on the weighted average of C contents (based on molecular formula) by elastomer type consumed in 1998, 2001, and 2002 (see Table A-62). The 1998 consumption data were obtained from the International Institute of Synthetic Rubber Producers (IISRP) press release *Synthetic Rubber Use Growth to Continue Through 2004, Says IISRP and RMA* (IISRP 2000). The 2001 and 2002 consumption data were obtained from the IISRP press release, *IISRP Forecasts Moderate Growth in North America to 2007* (IISRP 2003).

The rubber in tires that is abraded during use (the difference between new tire and scrap tire rubber weight) was considered to be 100 percent emitted. Other than abraded rubber, there were no emissive uses of scrap tire and non-tire rubber identified, so 100 percent of the non-abraded amount was assumed stored. Emissions related to the combustion of rubber in scrap tires and consumer goods can be found in the Incineration of Waste section of the Energy chapter.

Table A-62: 2002 Rubber Consumption (kt) and C Content (%)

Elastomer Type	2002 Consumption (kt)[a]	C Content
SBR Solid	768	91%
Polybutadiene	583	89%
Ethylene Propylene	301	86%
Polychloroprene	54	59%
NBR Solid	84	77%
Polyisoprene	58	88%
Others	367	88%
Weighted Average	**NA**	**90%**
Total	**2,215**	**NA**

Note: Totals may not sum due to independent rounding.
NA (Not Applicable)
[a] Includes consumption in Canada.

Synthetic Fibers

Annual synthetic fiber production data were obtained from the ACC, as published in the *Guide to the Business of Chemistry* (ACC 2020a), and the Fiber Economics Bureau, as published in *Chemical & Engineering News* (FEB 2001, 2003, 2005, 2007, 2009, 2010, 2011, 2012, 2013). For acrylic fiber, the most recent data available were for 2012, so it was assumed that the 2013, 2014, 2015, 2016, 2017, 2018, and 2019 consumption was equal to that of 2012. For polyester, nylon, and olefin, the most recent data were for 2019. These data are organized by year and fiber type. For each fiber, a C content was assigned based on molecular formula (see Table A-63). For polyester, the C content for poly (ethylene terephthalate) (PET) was used as a representative compound. For nylon, the average C content of nylon 6 and nylon 6.6 was used, since these are the most widely produced nylon fibers. Cellulosic fibers, such as acetate and rayon, have been omitted from the synthetic fibers' C accounting displayed here because much of their C is of biogenic origin and carbon fluxes from biogenic compounds are accounted for in the Land Use, Land-Use Change and Forestry chapter. These fibers account for only 4 percent of overall fiber production by weight.

There were no emissive uses of fibers identified, so 100 percent of the C was considered stored. Note that emissions related to the combustion of textiles in municipal solid waste are accounted for under the Incineration of Waste section of the Energy chapter.

Table A-63: 2019 Fiber Production (MMT), C Content (%), and C Stored (MMT CO_2 Eq.)

Fiber Type	Production (MMT)	C Content	C Stored (MMT CO_2 Eq.)
Polyester	1.3	63%	2.9
Nylon	0.5	64%	1.2
Olefin	1.1	86%	3.6
Acrylic	+	68%	0.1
Total	**3.0**	**NA**	**7.8**

Note: Totals may not sum due to independent rounding.
+ Does not exceed 0.05 MMT.
NA (Not Applicable)

Pesticides

Pesticide consumption data were obtained from the *1994/1995, 1996/1997, 1998/1999, 2000/2001, 2006/2007, and 2008-2012 Pesticides Industry Sales and Usage Market Estimates* (EPA 1998, 1999, 2002, 2004, 2011b, 2017) reports. The most recent data available were for 2012, so it was assumed that the 2013 through 2019 consumption was equal to that of 2012. Active ingredient compound names and consumption weights were available for the top 25 agriculturally-used pesticides and top 10 pesticides used in the home and garden and the industry/commercial/government categories. The report provides a range of consumption for each active ingredient; the midpoint was used to represent actual consumption. Each of these compounds was assigned a C content value based on molecular formula. If the compound contained aromatic rings substituted with chlorine or other halogens, then the compound was considered persistent and the C in the compound was assumed to be stored. All other pesticides were assumed to release their C to the atmosphere. Over one-third of 2012 total pesticide active ingredient consumption was not specified by chemical type in the *Sales and Usage* report (EPA 2017). This unspecified portion of the active ingredient consumption was treated as a single chemical and assigned a C content and a storage factor based on the weighted average of the known chemicals' values.

Table A-64: Active Ingredient Consumption in Pesticides (Million lbs.) and C Emitted and Stored (MMT CO_2 Eq.) in 2012

Pesticide Use[a]	Active Ingredient (Million lbs.)	C Emitted (MMT CO_2 Eq.)	C Stored (MMT CO_2 Eq.)
Agricultural Uses	606.0	0.2	0.1
Non-Agricultural Uses	58.0	+	+
Home & Garden	39.5	+	+
Industry/Gov't/Commercial	28.0	+	+
Other	342.0	0.1	0.1
Total	**1,006.0**	**0.3**	**0.2**

Note: Totals may not sum due to independent rounding.

+ Does not exceed 0.05 MMT CO_2 Eq.

[a] 2012 estimates (EPA 2017).

Soaps, Shampoos, and Detergents

Cleansers—soaps, shampoos, and detergents—are among the major consumer products that may contain fossil C. All of the C in cleansers was assumed to be fossil-derived, and, as cleansers eventually biodegrade, all of the C was assumed to be emitted. The first step in estimating C flows was to characterize the "ingredients" in a sample of cleansers. For this analysis, cleansers were limited to the following personal household cleaning products: bar soap, shampoo, laundry detergent (liquid and granular), dishwasher detergent, and dishwashing liquid. Data on the annual consumption of household personal cleansers were obtained from the U.S. Census Bureau 1992, 1997, 2002, 2007, 2012 Economic Census (U.S. Bureau of the Census 1994, 1999, 2004, 2009, 2014). Production values, given in terms of the value of shipments, for 1990 and 1991 were assumed to be the same as the 1992 value; consumption was interpolated between 1992 and 1997, 1997 and 2002, 2002 and 2007, and 2007 and 2012; production for 2013 through 2019 was assumed to equal the 2012 value. Cleanser production values were adjusted by import and export data to develop U.S. consumption estimates.

Chemical formulae were used to determine C contents (as percentages) of the ingredients in the cleansers. Each product's overall C content was then derived from the composition and contents of its ingredients. From these values the mean C content for cleansers was calculated to be 21.9 percent.

The Census Bureau presents consumption data in terms of quantity (in units of million gallons or million pounds) and/or terms of value (thousands of dollars) for eight specific categories, such as "household liquid laundry detergents, heavy duty" and "household dry alkaline automatic dishwashing detergents." Additionally, the report provides dollar values for the total consumption of "soaps, detergents, etc.—dry" and "soaps, detergents, etc.—liquid." The categories for which both quantity and value data are available is a subset of total production. Those categories that presented both quantity and value data were used to derive pounds per dollar and gallons per dollar conversion rates, and they were extrapolated (based on the Census Bureau estimate of total value) to estimate the total quantity of dry and liquid[38] cleanser categories, respectively.

Next, the total tonnage of cleansers was calculated (wet and dry combined) for 1997. Multiplying the mean C content (21.9 percent) by this value yielded an estimate of 4.6 MMT CO_2 Eq. in cleansers for 1997. For all subsequent

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[38] A density of 1.05 g/mL—slightly denser than water—was assumed for liquid cleansers.

years, it was assumed that the ratio of value of shipments to total carbon content remained constant. For 1998 through 2019, value of shipments was adjusted to 1997 dollars using the producer price index for soap and other detergent manufacturing (Bureau of Labor Statistics 2020). The ratio of value of shipments to carbon content was then applied to arrive at total carbon content of cleansers. Estimates are shown in Table A-65.

Table A-65: C Emitted from Utilization of Soaps, Shampoos, and Detergents (MMT CO_2 Eq.)

	1990	1995	2000	2005	2015	2016	2017	2018	2019
C Emissions	3.6	4.2	4.5	6.7	4.8	4.7	4.7	4.7	4.7

Antifreeze and Deicers

Glycol compounds, including ethylene glycol, propylene glycol, diethylene glycol, and triethylene glycol, are used as antifreeze in motor vehicles, deicing fluids for commercial aircraft, and other similar uses. These glycol compounds are assumed to ultimately enter wastewater treatment plants where they are degraded by the wastewater treatment process to CO_2 or to otherwise biodegrade to CO_2. Glycols are water soluble and degrade rapidly in the environment (Howard 1993).

Annual production data for each glycol compound used as antifreeze and deicers were obtained from the *Guide to the Business of Chemistry* (ACC 2020a) and the EPA Chemical Data Access Tool (CDAT) (EPA 2014). Import and export data were used to adjust annual production data to annual consumption data. The percentage of the annual consumption of each glycol compound used for antifreeze and deicing applications was estimated from Chemical Profiles data published on The Innovation Group website.[39] and from similar data published in the Chemical Market Reporter, which became ICIS Chemical Business in 2005.[40] Production data for propylene glycol, diethylene glycol, and triethylene glycol are no longer reported in the Guide to the Business of Chemistry, so data from ICIS Chemical Business on total demand was used with import and export data to estimate production of these chemicals. ICIS last reported total demand for propylene glycol and diethylene glycol in 2006, and triethylene glycol demand in 2007. EPA reported total U.S. production of propylene glycol, diethylene glycol, and triethylene glycol in 2012 in the CDAT (EPA 2014). Total demand for these compounds for 2012 was calculated from the 2012 production data using import and export data. Demand for propylene glycol and diethylene glycol was interpolated for years between 2006 and 2012, and demand for triethylene glycol was interpolated for years between 2007 and 2012, using the calculated 2012 total demand values for each compound and the most recently reported total demand data from ICIS. Values for 2014, 2015, 2016, 2017, 2018, and 2019 for these compounds were assumed to be the same as the 2012 values.

The glycol compounds consumed in antifreeze and deicing applications is assumed to be 100 percent emitted as CO_2. Emissions of CO_2 from utilization of antifreeze and deicers are summarized in Table A-66.

Table A-66: C Emitted from Utilization of Antifreeze and Deicers (MMT CO_2 Eq.)

	1990	1995	2000	2005	2015	2016	2017	2018	2019
C Emissions	1.2	1.4	1.5	1.2	1.0	1.0	1.0	1.1	1.0

Food Additives

Petrochemical feedstocks are used to manufacture synthetic food additives, including preservatives, flavoring agents, and processing agents. These compounds include glycerin, propylene glycol, benzoic acid, and other compounds. These compounds are incorporated into food products, and are assumed to ultimately enter wastewater treatment plants where they are degraded by the wastewater treatment processes to CO_2 or to otherwise biodegrade to CO_2. Certain food additives, e.g., glycerin, are manufactured both from petrochemical feedstocks and from biogenic feedstocks. Food additives that are derived from biogenic feedstocks are accounted for in the Land Use, Land-Use Change and Forestry chapter.

Annual production data for food additive compounds were obtained from the *Guide to the Business of Chemistry* (ACC 2020a). Historical values for adipic acid, acetic acid, and maleic anhydride were adjusted according to the most recent data in the 2019 *Guide to the Business of Chemistry*. Import and export data were used to adjust annual production data to annual consumption data. The percentage of the annual consumption of food additive compounds

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[39] See <http://www.the-innovation-group.com/ChemProfiles>.

[40] See <http://www.icis.com/home/default.aspx>.

was estimated from Chemical Profiles data published on The Innovation Group website[41] and from similar data published in the Chemical Market Reporter, which became ICIS Chemical Business in 2005.[42] Production data for several food additive compounds are no longer reported in the *Guide to the Business of Chemistry*, so data from ICIS Chemical Business on total demand was used with import and export data to estimate production of these chemicals.

ICIS last reported total demand for glycerin and benzoic acid in 2007, and demand for propionic acid in 2008. Total demand for dipropylene glycol was last reported by ICIS in 2004. ICIS last reported cresylic acid demand in 1999. EPA reported total U.S. production of these compounds in 2012 in the CDAT (EPA 2014). Total demand for these compounds for 2012 was calculated from the 2012 production data using import and export data. Demand for each of these compounds was interpolated for years between the most recently reported total demand data from ICIS and 2012, using the calculated 2012 total demand values for each compound. Values for 2014, 2015, 2016, 2017, 2018, and 2019 for these compounds were assumed to be the same as the 2012 values.

The consumption of synthetic food additives is assumed to be 100 percent emitted as CO_2. Emissions of CO_2 from utilization of synthetic food additives are summarized in Table A-67.

Table A-67: C Emitted from Utilization of Food Additives (MMT CO_2 Eq.)

	1990	1995	2000	2005	2015	2016	2017	2018	2019
C Emissions	0.6	0.7	0.7	0.8	1.1	1.1	1.1	1.1	1.1

Silicones

Silicone compounds (e.g., polymethyl siloxane) are used as sealants and in manufactured products. Silicone compounds are manufactured from petrochemical feedstocks including methyl chloride. It is assumed that petrochemical feedstocks used to manufacture silicones are incorporated into the silicone products and not emitted as CO_2 in the manufacturing process. It is also assumed that the C contained in the silicone products is stored, and not emitted as CO_2.

Import and export data were used to adjust annual production data to annual consumption data. The percentage of the annual consumption of each silicone manufacturing compound was estimated from Chemical Profiles data published on The Innovation Group website and from similar data published in the Chemical Market Reporter, which became ICIS Chemical Business in 2005.[43] ICIS last reported production of methyl chloride in 2007. EPA reported total U.S. production of methyl chloride in 2012 in the CDAT (EPA 2014). Total consumption of methyl chloride for 2012 was calculated from the 2012 production data using import and export data. Production of methyl chloride was interpolated for years between 2007 and 2012, using the calculated 2012 total production value for methyl chloride and the most recently reported total production data from ICIS. The production values for 2014, 2015, 2016, 2017, 2018 and 2019 were assumed to be the same as the 2012 value.

The consumption of silicone manufacturing compounds is assumed to be 100 percent stored, and not emitted as CO_2. Storage of silicone manufacturing compounds is summarized in Table A-68.

Table A-68: C Stored in Silicone Products (MMT CO_2 Eq.)

	1990	1995	2000	2005	2015	2016	2017	2018	2019
C Storage	0.3	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5

Uncertainty

A Tier 2 Monte Carlo analysis was performed using @RISK software to determine the level of uncertainty surrounding the estimates of the feedstocks C storage factor and the quantity of C emitted from feedstocks in 2019. The Tier 2 analysis was performed to allow the specification of probability density functions for key variables, within a computational structure that mirrors the calculation of the Inventory estimate. Statistical analyses or expert judgments of uncertainty were not available directly from the information sources for the activity variables; thus, uncertainty

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[41] See <http://www.the-innovation-group.com/ChemProfiles>.

[42] See <http://www.icis.com/home/default.aspx>.

[43] See <http://www.icis.com/home/default.aspx>.

estimates were determined using assumptions based on source category knowledge. Uncertainty estimates for production data (the majority of the variables) were assumed to exhibit a normal distribution with a relative error of ±20 percent in the underlying EIA estimates, plus an additional ±15 percent to account for uncertainty in the assignment of imports and exports. An additional 10 percent (for a total of ±45 percent) was applied to the production of other oils (>401 degrees Fahrenheit) to reflect the additional uncertainty in the assignment of part of the production quantity to industrial processes. A relatively narrow uniform distribution ±1 percent to ±15 percent, depending on the fuel type) was applied to each C coefficient.

The Monte Carlo analysis produced a storage factor distribution with a standard deviation of 7 percent and the 95 percent confidence interval of 50 percent and 73 percent. This compares to the calculated Inventory estimate of 62 percent. The analysis produced a C emission distribution with a standard deviation of 28.5 MMT CO_2 Eq. and 95 percent confidence limits of 56.4 and 160.4 MMT CO_2 Eq. This compares with a calculated Inventory estimate of 99.3 MMT CO_2 Eq.

The apparently tight confidence limits for the storage factor and C storage probably understate uncertainty, as a result of the way this initial analysis was structured. As discussed above, the storage factor for feedstocks is based on an analysis of six fates that result in long-term storage (e.g., plastics production), and eleven that result in emissions (e.g., volatile organic compound emissions). Rather than modeling the total uncertainty around all 17 of these fate processes, the current analysis addresses only the storage fates, and assumes that all C that is not stored is emitted. As the production statistics that drive the storage factors are relatively well-characterized, this approach yields a result that is probably biased toward understating uncertainty.

As far as specific sources of uncertainty, there are several cross-cutting factors that pervade the characterization of C flows for feedstocks. The aggregate storage factor for petrochemical feedstocks (industrial other coal, natural gas for non-fertilizer uses, HGL, pentanes plus, naphthas, other oils, still gas, special naphtha) is based on assuming that the ultimate fates of all of these fuel types—in terms of storage and emissions—are similar. In addition, there are uncertainties associated with the simplifying assumptions made for each end use category C estimate. Generally, the estimate for a product is subject to one or more of the following uncertainties:

- The value used for estimating the C content has been assumed or assigned based upon a representative compound.
- The split between C storage and emission has been assumed based on an examination of the environmental fate of the products in each end use category.
- Environmental fates leading to emissions are assumed to operate rapidly, i.e., emissions are assumed to occur within one year of when the fossil C enters the non-energy mass balance. Some of the pathways that lead to emissions as CO_2 may actually take place on a time-scale of several years or decades. By attributing the emissions to the year in which the C enters the mass balance (i.e., the year in which it leaves refineries as a non-energy fuel use and thus starts being tracked by EIA), this approach has the effect of “front-end loading” the emission profile.

Another cross-cutting source of uncertainty is that for several sources the amount of C stored or emitted was calculated based on data for only a single year. This specific year may not be representative of storage for the entire Inventory period. Sources of uncertainty associated with specific elements of the analysis are discussed below.

Import and export data for petrochemical feedstocks were obtained from EIA, the National Petroleum Refiners Association, and the BoC for the major categories of petrochemical feedstocks (EIA 2001; NPRA 2001; and U.S. Bureau of the Census 2017). The complexity of the organic chemical industry, with multiple feedstocks, intermediates, and subtle differences in nomenclature, makes it difficult to ensure that the adjustments to the EIA data for imports and exports is accurate and the approach used here may underestimate or overestimate net exports of C.

Oxidation factors have been applied to non-energy uses of petrochemical feedstocks in the same manner as for energy uses. However, for those fuels where IPCC storage factors are used, this “oxidation factor” may be inherent in the storage factor applied when calculating emissions from non-energy consumption, which would result in a double-counting of the unoxidized C. Oxidation factors are small corrections, on the order of 1 percent, and therefore application of oxidation factors to non-energy uses may result in a slight underestimation of C emissions from non-energy uses.

The major uncertainty in using the TRI data is the possibility of double counting emissions that are already accounted for in the NMVOC data (see above) and in the storage and emission assumptions used. The approach for predicting environmental fate simplifies some complex processes, and the balance between storage and emissions is very sensitive to the assumptions on fate. Extrapolating from known to unknown characteristics also introduces uncertainty. The two extrapolations with the greatest uncertainty are: (1) that the release media and fate of the off-site releases were assumed to be the same as for on-site releases, and (2) that the C content of the least frequent 10 percent of TRI releases was assumed to be the same as for the chemicals comprising 90 percent of the releases. However, the contribution of these chemicals to the overall estimate is small. The off-site releases only account for 3 percent of the total releases, by weight, and, by definition, the less frequent compounds only account for 10 percent of the total releases.

The principal sources of uncertainty in estimating CO_2 emissions from solvent evaporation and industrial NMVOC emissions are in the estimates of (a) total emissions and (b) their C content. Solvent evaporation and industrial NMVOC emissions reported by EPA are based on a number of data sources and emission factors, and may underestimate or overestimate emissions. The C content for solvent evaporation emissions is calculated directly from the specific solvent compounds identified by EPA as being emitted, and is thought to have relatively low uncertainty. The C content for industrial emissions has more uncertainty, however, as it is calculated from the average C content of an average volatile organic compound based on the list of the most abundant measured NMVOCs provided in EPA (2002a).

Uncertainty in the hazardous waste combustion analysis is introduced by the assumptions about the composition of combusted hazardous wastes, including the characterization that hazardous wastes are similar to mixtures of water, noncombustibles, and fuel equivalent materials. Another limitation is the assumption that all of the C that enters hazardous waste combustion is emitted—some small fraction is likely to be sequestered in combustion ash—but given that the destruction and removal efficiency for hazardous organics is required to meet or exceed 99.99 percent, this is a very minor source of uncertainty. C emission estimates from hazardous waste should be considered central value estimates that are likely to be accurate to within ±50 percent.

The amount of feedstocks combusted for energy recovery was estimated from data included in the *Manufacturers Energy Consumption Surveys* (MECS) for 1991, 1994, 1998, 2002, 2006, 2010, 2014, and 2018 (EIA 1994, 1997, 2001, 2005, 2010, 2013b, 2017, 2021). MECS is a comprehensive survey that is conducted every four years and intended to represent U.S. industry as a whole, but because EIA does not receive data from all manufacturers (i.e., it is a sample rather than a census), EIA must extrapolate from the sample. Also, the “other” fuels are identified in the MECS data in broad categories, including refinery still gas; waste gas; waste oils, tars, and related materials; petroleum coke, coke oven and blast furnace gases; and other uncharacterized fuels. Moreover, the industries using these “other” fuels are also identified only in broad categories, including the petroleum and coal products, chemicals, primary metals, nonmetallic minerals, and other manufacturing sectors. The “other” fuel consumption data are reported in BTUs (energy units) and there is uncertainty concerning the selection of a specific conversion factor for each broad “other” fuel category to convert energy units to mass units. Taken as a whole, the estimate of energy recovery emissions probably introduces more uncertainty than any other element of the non-energy analysis.

Uncertainty in the C storage estimate for plastics arises primarily from four factors. First, production of some plastic resins is not tracked directly and must be estimated based on other market data. Second, the raw data on production for several resins include Canadian and/or Mexican production and may overestimate the amount of plastic produced from U.S. fuel feedstocks; this analysis includes adjustments to “back out” the Canadian and Mexican values, but these adjustments are approximate. Third, the assumed C content values are estimates for representative compounds, and thus do not account for the many formulations of resins available. This uncertainty is greater for resin categories that are generic (e.g., phenolics, other styrenics, nylon) than for resins with more specific formulations (e.g., polypropylene, polyethylene). Fourth, the assumption that all of the C contained in plastics is stored ignores certain end uses (e.g., adhesives and coatings) where the resin may be released to the atmosphere; however, these end-uses are likely to be small relative to use in plastics.

The quantity of C stored in synthetic rubber only accounts for the C stored in scrap tire synthetic rubber. The value does not take into account the rubber stored in other durable goods, clothing, footwear, and other non-durable goods, or containers and packaging. This adds uncertainty to the total mass balance of C stored. There are also uncertainties as to the assignment of C content values; however, they are much smaller than in the case of plastics. There are probably fewer variations in rubber formulations than in plastics, and the range of potential C content values is much narrower. Lastly, assuming that all of the C contained in rubber is stored ignores the possibility of volatilization or degradation during product lifetimes. However, the proportion of the total C that is released to the atmosphere during use is probably negligible.

A small degree of uncertainty arises from the assignment of C content values in textiles; however, the magnitude of this uncertainty is less than that for plastics or rubber. Although there is considerable variation in final textile products, the stock fiber formulations are standardized and proscribed explicitly by the Federal Trade Commission.

For pesticides, the largest source of uncertainty involves the assumption that an active ingredient's C is either zero percent stored or 100 percent stored. This split is a generalization of chemical behavior, based upon active-ingredient molecular structure, and not on compound-specific environmental data. The mechanism by which a compound is bound or released from soils is very complicated and can be affected by many variables, including the type of crop, temperature, application method, and harvesting practice. Another smaller source of uncertainty arises from the C content values applied to the unaccounted for portion of active ingredient. C contents vary widely among pesticides, from 7 to 77 percent, and the remaining pesticides may have a chemical make-up that is very different from the 49 pesticides that have been examined. Additionally, pesticide consumption data were only available for 1987, 1993, 1995, 1997, 1999, 2001, 2007, 2009, and 2012; the majority of the time series data were interpolated or held constant at the latest (2012) value. Another source of uncertainty is that only the "active" ingredients of pesticides are considered in the calculations; the "inactive" ingredients may also be derived from petrochemical feedstocks.

It is important to note that development of this uncertainty analysis is a multi-year process. The current feedstocks analysis examines NEU fuels that end in storage fates. Thus, only C stored in pesticides, plastics, synthetic fibers, synthetic rubbers, silicones, and TRI releases to underground injection and Subtitle C landfills is accounted for in the uncertainty estimate above. In the future this analysis will be expanded to include the uncertainty surrounding emitted fates in addition to the storage fates. Estimates of variable uncertainty will also be refined where possible to include fewer assumptions. With these major changes in future Inventories, the uncertainty estimate is expected to change, and likely increase. An increase in the uncertainty estimate in the coming years will not indicate that the Inventory calculations have become less certain, but rather that the methods for estimating uncertainty have become more comprehensive; thus, potential future changes in the results of this analysis will reflect a change in the uncertainty analysis, not a change in the Inventory quality.

Asphalt and Road Oil

Asphalt is one of the principal non-energy uses of fossil fuels. The term "asphalt" generally refers to a mixture of asphalt cement and a rock material aggregate, a volatile petroleum distillate, or water. For the purposes of this analysis, "asphalt" is used interchangeably with asphalt cement, a residue of crude oil. Though minor amounts of C are emitted during production, asphalt has an overall C storage factor of almost 100 percent, as discussed below.

Paving is the primary application of asphalt cement, comprising 86 percent of production. The three types of asphalt paving produced in the United States are hot mix asphalt (HMA), cut-backs, and emulsified asphalt. HMA, which makes up 90 percent of total asphalt paving (EPA 2001), contains asphalt cement mixed with an aggregate of rock materials. Cut-back asphalt is composed of asphalt cement thinned with a volatile petroleum distillate (e.g., naphtha). Emulsified asphalt contains only asphalt cement and water. Roofing products are the other significant end use of asphalt cement, accounting for approximately 14 percent of U.S. production (Kelly 2000). No data were available on the fate of C in asphalt roofing; it was assumed that it has the same fate as C in asphalt paving applications.

Methodology and Data Sources

A C storage factor was calculated for each type of asphalt paving. The fraction of C emitted by each asphalt type was multiplied by consumption data for asphalt paving (EPA 2001) to estimate a weighted average C storage factor for asphalt as a whole.

The fraction of C emitted by HMA was determined by first calculating the organic emissions (volatile organic compounds [VOCs], carbon monoxide [CO], polycyclic aromatic hydrocarbons [PAHs], hazardous air pollutants [HAPs], and phenol) from HMA paving, using emission factors reported in EPA (2001) and total HMA production.[44] The next step was to estimate the C content of the organic emissions. This calculation was based on the C content of CO and phenol,

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[44] The emission factors are expressed as a function of asphalt paving tonnage (i.e., including the rock aggregate as well as the asphalt cement).

and an assumption of 85 percent C content for PAHs and HAPs. The C content of asphalt paving is a function of (1) the proportion of asphalt cement in asphalt paving, assumed to be 8 percent asphalt cement content based on EPA (2001), and (2) the proportion of C in asphalt cement. For the latter factor, all paving types were characterized as having a mass fraction of 85 percent C in asphalt cement, based on the assumption that asphalt is primarily composed of saturated paraffinic hydrocarbons. By combining these estimates, the result is that over 99.6 percent of the C in asphalt cement was retained (i.e., stored), and less than 0.4 percent was emitted.

Cut-back asphalt is produced in three forms: rapid, medium, and slow cure. The production processes for all three forms emit C primarily from the volatile petroleum distillate used in the process as a diluent to thin the asphalt cement so that it can be applied more readily (EPA 2001).

A mass balance on C losses from asphalt was constructed by first estimating the amount of carbon emitted as VOCs. Values for medium cure asphalt are used to represent all cut-back asphalt. The average weight of distillates used in medium cure cut-back asphalt (35 percent) is multiplied by the loss rate (as emissions of VOCs) of 70 percent from the *Emissions Inventory Guidebook* to arrive at an estimate that 25 percent of the diluent is emitted (Environment Canada 2006). Next, the fraction of C in the asphalt/ diluent mix that is emitted was estimated, assuming 85 percent C content; this yields an overall storage factor of 93.5 percent for cut-back asphalt.

One caveat associated with this calculation is that it is possible that the carbon flows for asphalt and diluent (volatile petroleum distillate) are accounted for separately in the EIA statistics on fossil fuel flows, and thus the mass balance calculation may need to re-map the system boundaries to correctly account for carbon flows. EPA plans to re-evaluate this calculation in the future.

It was assumed that there was no loss of C from emulsified asphalt (i.e., the storage factor is 100 percent) based on personal communication with an expert from Akzo Nobel Coatings, Inc. (James 2000).

Data on asphalt and road oil consumption and C content factors were supplied by EIA. Hot mix asphalt production and emissions factors, and the asphalt cement content of HMA were obtained from *Hot Mix Asphalt Plants Emissions Assessment Report* from EPA's *AP-42* (EPA 2001) publication. The consumption data for cut-back and emulsified asphalts were taken from a Moulthrop, et al. study used as guidance for estimating air pollutant emissions from paving processes (EIIP 2001). "Asphalt Paving Operation" *AP-42* (EPA 2001) provided the emissions source information used in the calculation of the C storage factor for cut-back asphalt. The storage factor for emulsified asphalt was provided by Alan James of Akzo Nobel Coatings, Inc. (James 2000).

Uncertainty

A Tier 2 Monte Carlo analysis was performed using @RISK software to determine the level of uncertainty surrounding the estimates of the asphalt C storage factor and the quantity of C stored in asphalt in 2019. The Tier 2 analysis was performed to allow the specification of probability density functions for key variables, within a computational structure that mirrors the calculation of the Inventory estimate. Statistical analyses or expert judgments of uncertainty were not available directly from the information sources for the activity variables; thus, uncertainty estimates were determined using assumptions based on source category knowledge. Uncertainty estimates for asphalt production were assumed to be ±20 percent, while the asphalt property variables were assumed to have narrower distributions. A narrow uniform distribution, with maximum 5 percent uncertainty (± 5 percent) around the mean, was applied to the C content coefficient.

The Monte Carlo analysis produced a tight distribution of storage factor values, with the 95 percent confidence interval of 99 percent and 100 percent. This compares to the storage factor value used in the Inventory of 99.6 percent. The analysis produced a C emission distribution with a standard deviation of 0.1 and 95 percent confidence limits of 0.1 MMT CO_2 Eq. and 0.6 MMT CO_2 Eq. This compares to an Inventory calculated estimate of 0.3 MMT CO_2 Eq.

The principal source of uncertainty is that the available data are from short-term studies of emissions associated with the production and application of asphalt. As a practical matter, the cement in asphalt deteriorates over time, contributing to the need for periodic re-paving. Whether this deterioration is due to physical erosion of the cement and continued storage of C in a refractory form or physicochemical degradation and eventual release of CO_2 is uncertain. Long-term studies may reveal higher lifetime emissions rates associated with degradation.

Many of the values used in the analysis are also uncertain and are based on estimates and professional judgment. For example, the asphalt cement input for hot mix asphalt was based on expert advice indicating that the range is variable—from about 3 to 5 percent—with actual content based on climate and geographical factors (Connolly

2000). Over this range, the effect on the calculated C storage factor is minimal (on the order of 0.1 percent). Similarly, changes in the assumed C content of asphalt cement would have only a minor effect.

The consumption figures for cut-back and emulsified asphalts are based on information reported for 1994. More recent trends indicate a decrease in cut-back use due to high VOC emission levels and a related increase in emulsified asphalt use as a substitute. This change in trend would indicate an overestimate of emissions from asphalt.

Future improvements to this uncertainty analysis, and to the overall estimation of a storage factor for asphalt, include characterizing the long-term fate of asphalt.

Lubricants

Lubricants are used in industrial and transportation applications. They can be subdivided into oils and greases, which differ in terms of physical characteristics (e.g., viscosity), commercial applications, and environmental fate. According to EIA (2020), the C content from U.S. production of lubricants in 2019 was approximately 5.1 MMT C. Based on apportioning oils and greases to various environmental fates, and characterizing those fates as resulting in either long-term storage or emissions, the overall C storage factor was estimated to be 9.2 percent; thus, emissions in 2019 were about 4.6 MMT C, or 16.9 MMT CO_2 Eq.

Methodology and Data Sources

For each lubricant category, a storage factor was derived by identifying disposal fates and applying assumptions as to the disposition of the C for each practice. An overall lubricant C storage factor was calculated by taking a production-weighted average of the oil and grease storage factors.

Oils

Regulation of used oil in the United States has changed dramatically over the past 20 years.[45] The effect of these regulations and policies has been to restrict landfilling and dumping, and to encourage collection of used oil. The economics of the petroleum industry have generally not favored re-refining—instead, most of the used oil that has been collected has been combusted.

Table A-69 provides an estimated allocation of the fates of lubricant oils (Rinehart 2000), along with an estimate of the proportion of C stored in each fate. The ultimate fate of the majority of oils (about 84 percent) is combustion, either during initial use or after collection as used oil. Combustion results in 99 percent oxidation to CO_2 (EIIP 1999), with correspondingly little long-term storage of C in the form of ash. Dumping onto the ground or into storm sewers, primarily by "do-it-yourselfers" who change their own oil, is another fate that results in conversion to CO_2 given that the releases are generally small and most of the oil is biodegraded (based on the observation that land farming—application to soil—is one of the most frequently used methods for degrading refinery wastes). In the landfill environment, which tends to be anaerobic within municipal landfills, it is assumed that 90 percent of the oil persists in an undegraded form, based on analogy with the persistence of petroleum in native petroleum-bearing strata, which is also anaerobic. Re-refining adds a recycling loop to the fate of oil. Re-refined oil was assumed to have a storage factor equal to the weighted average for the other fates (i.e., after re-refining, the oil would have the same probability of combustion, landfilling, or dumping as virgin oil), that is, it was assumed that about 97 percent of the C in re-refined oil is ultimately oxidized. Because of the dominance of fates that result in eventual release as CO_2, only about 3 percent of the C in oil lubricants goes into long-term storage.

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[45] For example, the U.S. EPA "RCRA (Resource Conservation and Recovery Act) On-line" web site (<http://www.epa.gov/rcraonline/>) has over 50 entries on used oil regulation and policy for 1994 through 2000.

Table A-69: Commercial and Environmental Fate of Oil Lubricants (Percent)

Fate of Oil	Portion of Total Oil	C Stored
Combusted During Use	**20%**	**0.2%**
Not Combusted During Use	**80%**	**2.7%**
Combusted as Used Oil[a]	64%	0.6%
Dumped on the ground or in storm sewers	6%	NA
Landfilled	2%	1.8%
Re-refined into lube oil base stock and other products	8%	0.2%
Weighted Average	**NA**	**2.9%**

NA (Not Applicable)

[a] For example, in boilers or space heaters.

Greases

Table A-70 provides analogous estimates for lubricant greases. Unlike oils, grease is generally not combusted during use, and combustion for energy recovery and re-refining is thought to be negligible. Although little is known about the fate of waste grease, it was assumed that 90 percent of the non-combusted portion is landfilled, and the remainder is dumped onto the ground or storm sewers. Because much of the waste grease will be in containers that render it relatively inaccessible to biodegradation, and because greases contain longer chain paraffins, which are more persistent than oils, it was assumed that 90 percent and 50 percent of the C in landfilled and dumped grease, respectively, would be stored. The overall storage factor is 82 percent for grease.

Table A-70: Commercial and Environmental Fate of Grease Lubricants (Percent)

Fate of Grease	Portion of Total Grease	C Stored
Combusted During Use	**5%**	**0.1%**
Not Combusted During Use	**95%**	**81.7%**
Landfilled	90%	77.0%
Dumped on the ground or in storm sewers	10%	4.8%
Weighted Average	**NA**	**81.8%**

Having derived separate storage factors for oil and grease, the last step was to estimate the weighted average for lubricants as a whole. No data were found apportioning the mass of lubricants into these two categories, but the U.S. Census Bureau does maintain records of the value of production of lubricating oils and lubricating greases. These were retrieved from the relevant industry series summaries from the *1997 Economic Census* (U.S. Bureau of the Census 1999). Assuming that the mass of lubricants can be allocated according to the proportion of value of production (92 percent oil, 8 percent grease), applying these weights to the storage factors for oils and greases (3 percent and 82 percent) yields an overall storage factor of 9.2 percent.

Uncertainty

A Tier 2 Monte Carlo analysis was performed using @RISK software to determine the level of uncertainty surrounding the estimates of the lubricants weighted average C storage factor and the quantity of C emitted from lubricants in 2019. The Tier 2 analysis was performed to allow the specification of probability density functions for key variables, within a computational structure that mirrors the calculation of the Inventory estimate. Statistical analyses or expert judgments of uncertainty were not available directly from the information sources for the activity variables; thus, uncertainty estimates were determined using assumptions based on source category knowledge. Uncertainty estimates for oil and grease variables were assumed to have a moderate variance, in triangular or uniform distribution. Uncertainty estimates for lubricants production were assumed to be rather high (±20 percent). A narrow uniform distribution, with 6 percent uncertainty (± 6 percent) around the mean, was applied to the lubricant C content coefficient.

The Monte Carlo analysis produced a storage factor distribution with the 95 percent confidence interval of 4 percent and 18 percent. This compares to the calculated Inventory estimate of 9.2 percent. The analysis produced a C emission distribution approximating a normal curve with a standard deviation of 1.4 and 95 percent confidence limits of 14.0 MMT CO_2 Eq. and 19.6 MMT CO_2 Eq. This compares to an inventory-calculated estimate of 16.9 MMT CO_2 Eq.

The principal sources of uncertainty for the disposition of lubricants are the estimates of the commercial use, post-use, and environmental fate of lubricants, which, as noted above, are largely based on assumptions and judgment. There is no comprehensive system to track used oil and greases, which makes it difficult to develop a verifiable estimate of the commercial fates of oil and grease. The environmental fate estimates for percent of C stored are less uncertain, but also introduce uncertainty in the estimate.

The assumption that the mass of oil and grease can be divided according to their value also introduces uncertainty. Given the large difference between the storage factors for oil and grease, changes in their share of total lubricant production have a large effect on the weighted storage factor.

Future improvements to the analysis of uncertainty surrounding the lubricants C storage factor and C stored include further refinement of the uncertainty estimates for the individual activity variables.

Waxes

Waxes are organic substances that are solid at ambient temperature, but whose viscosity decreases as temperature increases. Most commercial waxes are produced from petroleum refining, though “mineral” waxes derived from animals, plants, and lignite (coal) are also used. An analysis of wax end uses in the United States, and the fate of C in these uses, suggests that about 42 percent of C in waxes is emitted, and 58 percent is stored.

Methodology and Data Sources

The National Petroleum Refiners Association (NPRA) considers the exact amount of wax consumed each year by end use to be proprietary (Maguire 2004). In general, about thirty percent of the wax consumed each year is used in packaging materials, though this percentage has declined in recent years. The next highest wax end use, and fastest growing end use, is candles, followed by construction materials and firelogs. Table A-71 categorizes some of the wax end uses, which the NPRA generally classifies into cosmetics, plastics, tires and rubber, hot melt (adhesives), chemically modified wax substances, and other miscellaneous wax uses (NPRA 2002).

Table A-71: Emissive and Non-emissive (Storage) Fates of Waxes: Uses by Fate and Percent of Total Mass

Use	Emissive	Non-emissive
Packaging	**6%**	**24%**
Non-packaging	**36%**	**34%**
Candles	18%	2%
Construction Materials	4%	14%
Firelogs	7%	+
Cosmetics	1%	2%
Plastics	1%	2%
Tires/Rubber	1%	1%
Hot Melts	1%	1%
Chemically Modified	+	1%
Other	2%	9%
Total	**42%**	**58%**

+ Does not exceed 0.5 percent.

A C storage factor for each wax end use was estimated and then summed across all end uses to provide an overall C storage factor for wax. Because no specific data on C contents of wax used in each end use were available, all wax products are assumed to have the same C content. Table A-72 categorizes wax end uses identified by the NPRA and lists the estimated C storage factor of each end use.

Table A-72: Wax End-Uses by Fate, Percent of Total Mass, Percent C Stored, and Percent of Total C Mass Stored

Use	Percent of Total Wax Mass	Percent of C Stored	Percent of Total C Mass Stored
Packaging	**30%**	**79%**	**24%**
Non-Packaging			
Candles	20%	10%	2%
Construction Materials	18%	79%	14%
Firelogs	7%	1%	+
Cosmetics	3%	79%	2%
Plastics	3%	79%	2%
Tires/Rubber	3%	47%	1%
Hot Melts	3%	50%	1%
Chemically Modified	1%	79%	1%
Other	12%	79%	9%
Total	**100%**	**NA**	**58%**

Notes: Totals may not sum due to independent rounding. Estimates of percent stored are based on ICF professional judgment.
+ Does not exceed 0.5 percent.
NA (Not Applicable)
Source mass percentages: NPRA (2002).

Emissive wax end-uses include candles, firelogs (synthetic fireplace logs), hotmelts (adhesives), matches, and explosives. At about 20 percent, candles consume the greatest portion of wax among emissive end uses. As candles combust during use, they release emissions to the atmosphere. For the purposes of the Inventory, it is assumed that 90 percent of C contained in candles is emitted as CO_2. In firelogs, petroleum wax is used as a binder and as a fuel, and is combusted during product use, likely resulting in the emission of nearly all C contained in the product. Similarly, C contained in hotmelts is assumed to be emitted as CO_2 as heat is applied to these products during use. It is estimated that 50 percent of the C contained in hot melts is stored. Together, candles, firelogs, and hotmelts constitute approximately 30 percent of annual wax production (NPRA 2002).

All of the wax utilized in the production of packaging, cosmetics, plastics, tires and rubber, and other products is assumed to remain in the product (i.e., it is assumed that there are no emissions of CO_2 from wax during the production of the product). Wax is used in many different packaging materials including wrappers, cartons, papers, paperboard, and corrugated products (NPRA 2002). Davie (1993) and Davie et al. (1995) suggest that wax coatings in packaging products degrade rapidly in an aerobic environment, producing CO_2; however, because packaging products ultimately enter landfills typically having an anaerobic environment, most of the C from this end use is assumed to be stored in the landfill.

In construction materials, petroleum wax is used as a water repellent on wood-based composite boards, such as particle board (IGI 2002). Wax used for this end-use should follow the life-cycle of the harvested wood used in product, which is classified into one of 21 categories, evaluated by life-cycle, and ultimately assumed to either be disposed of in landfills or be combusted (EPA 2003).

The fate of wax used for packaging, in construction materials, and for most remaining end uses is ultimately to enter the municipal solid waste (MSW) stream, where it is either combusted or sent to landfill for disposal. Most of the C contained in these wax products will be stored. It is assumed that approximately 21 percent of the C contained in these products will be emitted through combustion or at landfill. With the exception of tires and rubber, these end-uses are assigned a C storage factor of 79 percent.

Waxes used in tires and rubber follow the life cycle of the tire and rubber products. Used tires are ultimately recycled, landfilled, or combusted. The life-cycle of tires is addressed elsewhere in this annex as part of the discussion of rubber products derived from petrochemical feedstocks. For the purposes of the estimation of the C storage factor for waxes, wax contained in tires and rubber products is assigned a C storage factor of 47 percent.

Uncertainty

A Tier 2 Monte Carlo analysis was performed using @RISK software to determine the level of uncertainty surrounding the estimates of the wax C storage factor and the quantity of C emitted from wax in 2019. A Tier 2 analysis was performed to allow the specification of probability density functions for key variables, within a computational structure that mirrors the calculation of the Inventory estimate. Statistical analyses or expert judgments of uncertainty were not available directly from the information sources for the activity variables; thus, uncertainty estimates were determined using assumptions based on source category knowledge. Uncertainty estimates for wax variables were assumed to have a moderate variance, in normal, uniform, or triangular distribution; uniform distributions were applied to total consumption of waxes and the C content coefficients.

The Monte Carlo analysis produced a storage factor distribution, whose 95 percent confidence interval values fell within the range of 47 percent and 67 percent. This compares to the calculated Inventory estimate of 57.8 percent. The analysis produced an emission distribution, with the 95 percent confidence interval values of 0.2 MMT CO_2 Eq. and 0.6 MMT CO_2 Eq. This compares with a calculated Inventory estimate of 0.3 MMT CO_2 Eq., which falls within the range of 95 percent confidence limits established by this quantitative uncertainty analysis. Uncertainty associated with the wax storage factor is considerable due to several assumptions pertaining to wax imports/exports, consumption, and fates.

Miscellaneous Products

Miscellaneous products are defined by the U.S. Energy Information Administration as: "all finished [petroleum] products not classified elsewhere, e.g., petrolatum; lube refining by-products (e.g., aromatic extracts and tars); absorption oils; ram-jet fuel; petroleum rocket fuel; synthetic natural gas feedstocks; and specialty oils."

Methodology and Data Sources

The "miscellaneous products" category reported by EIA includes miscellaneous products that are not reported elsewhere in the EIA data set. The EIA does not have firm data concerning the amounts of various products that are being reported in the "miscellaneous products" category; however, EIA has indicated that recovered sulfur compounds from petroleum and natural gas processing, and potentially also carbon black feedstock could be reported in this category. Recovered sulfur has no carbon content and would not be reported in the NEU calculation or elsewhere in the Inventory. Based on this information, the miscellaneous products category reported by EIA was assumed to be mostly petroleum refinery sulfur compounds that do not contain carbon (EIA 2019). Therefore, the carbon content for miscellaneous products was updated to be zero across the time series. This resulted in recalculating historical emissions from 1990 through 2018.

Other Non-Energy Uses

The remaining fuel types use storage factors that are not based on U.S.-specific analysis. For industrial coking coal and distillate fuel oil, storage factors were taken from Marland and Rotty (1984). These factors are 0.1 and 0.5, respectively.

IPCC does not provide guidance on storage factors for the remaining fuel types (petroleum coke and other petroleum), and assumptions were made based on the potential fate of C in the respective NEUs. Specifically, the storage factor for petroleum coke is 0.3, based on information from Huurman (2006) indicating that petroleum coke is used in the Netherlands for production of pigments, with 30 percent being stored long-term. Carbon dioxide emissions from carbide production are implicitly accounted for in the storage factor calculation for the non-energy use of petroleum coke. The "other petroleum" category is reported by U.S. Territories and accounts mostly for the same products as miscellaneous products, but probably also includes some asphalt, known to be non-emissive. The exact amount of asphalt or any of the other miscellaneous products is confidential business information, but based on judgment, the storage factor for this category was estimated at 0.1.

For all these fuel types, the overall methodology simply involves multiplying C content by a storage factor, yielding an estimate of the mass of C stored. To provide a complete analysis of uncertainty for the entire NEU subcategory, the uncertainty around the estimate of "other" NEUs was characterized, as discussed below.

Uncertainty

A Tier 2 Monte Carlo analysis was performed using @RISK software to determine the level of uncertainty surrounding the weighted average of the remaining fuels' C storage factors and the total quantity of C emitted from these other fuels in 2019. A Tier 2 analysis was performed to allow the specification of probability density functions for key variables, within a computational structure that mirrors the calculation of the Inventory estimate. Statistical analyses or expert judgments of uncertainty were not available directly from the information sources for some of the activity variables; thus, uncertainty estimates were determined using assumptions based on source category knowledge. A uniform distribution was applied to coking coal consumption, while the remaining consumption inputs were assumed to be normally distributed. The C content coefficients were assumed to have a uniform distribution; the greatest uncertainty range of 10 percent (± 10 percent) around the Inventory value, was applied to coking coal. C coefficients for distillate fuel oil ranged from 18.5 to 21.1 MMT C/QBtu. The fuel-specific storage factors were assigned wide triangular distributions indicating greater uncertainty.

The Monte Carlo analysis produced a storage factor distribution with 95 percent confidence limits of 8 percent and 81 percent. This compares to the Inventory calculation of weighted average (across the various fuels) storage factor of about 11.3 percent. The analysis produced an emission distribution, with the 95 percent confidence limit of 2.5 MMT CO_2 Eq. and 13.9 MMT CO_2 Eq. This compares with the Inventory estimate of 12.0 MMT CO_2 Eq., which falls closer to the upper boundary of the 95 percent confidence limit. The uncertainty analysis results are driven primarily by the very broad uncertainty inputs for the storage factors.

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