

Annexes

The following twenty-eight annexes provide additional information to the material presented in the main body of this report. Annexes A through Q discuss methodologies for individual source categories in greater detail than was presented in the main body of the report and include explicit activity data and emission factor tables. Annex R analyzes the key sources in this report. Annex S presents a summary of Global Warming Potential values. Annexes T and U summarize U.S. emissions of ozone depleting substances (e.g., CFCs and HCFCs) and sulfur dioxide (SO₂), respectively. Annex V provides a complete list of emission sources assessed in this report. Annex W presents the IPCC reference approach for estimating CO₂ emissions from fossil fuel combustion. Annex X addresses the criteria for the inclusion of an emission source category and some of the sources that meet the criteria but are nonetheless excluded from U.S. estimates. Annex Y provides some useful constants, unit definitions, and conversions. Annexes Z and AA provide a listing of abbreviations and chemical symbols used. Finally, Annex AB contains a glossary of terms related to greenhouse gas emissions and inventories.

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ANNEX A

Methodology for Estimating Emissions of CO₂ from Fossil Fuel Combustion

Carbon dioxide (CO₂) emissions from fossil fuel combustion were estimated using a “bottom-up” methodology characterized by six steps. These steps are described below.

Step 1: Determine Energy Consumption by Fuel Type and Sector

The bottom-up methodology used by the United States for estimating CO₂ 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, sectoral-based emission estimates (IPCC/UNEP/OECD/IEA 1997). Basic consumption data are presented in Columns 2 through 8 of Table A-1 through Table A-12, with totals by fuel type in Column 8 and totals by end-use sector in the last rows. 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 “Energy Conversions” in Annex Y). 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 consumption data were aggregated by sector (i.e., residential, commercial, industrial, transportation, electricity generation, and U.S. territories), primary fuel type (e.g., coal, natural gas, and petroleum), and secondary fuel type (e.g., motor gasoline, distillate fuel, etc.). The 2001 total energy consumption across all sectors, including territories, and energy types was 82,933 trillion British thermal units (TBTu), as indicated in the last entry of Column 8 in Table A-1. This total includes fuel used for non-energy purposes and fuel consumed as international bunkers, both of which are deducted in later steps.

Electricity consumption 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 also reported separately. This total was consequently combined with the commercial electricity data. Fuel consumption data for electricity generation data by nonutility power producers were categorized by the EIA under a “direct use” category. These data were combined with electricity fuel use by the industrial sector. Further information on these electricity end uses is described in EIA’s *Annual Energy Review 2001* (EIA 2002a). Additionally, electricity consumption for the U.S. territories was estimated as the sum of the net electricity consumption in Puerto Rico, Guam, U.S. Virgin Islands, American Samoa, and U.S. Pacific Islands (EIA 2002b).

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 some coking coal, petroleum coke, and natural gas consumption for ammonia production to the Industrial Processes chapter, 2) corrections for synthetic natural gas production, 3) corrections for ethanol added to motor gasoline, and 4) corrections for biogas in natural gas.

First, portions of the fuel consumption data for three fuel categories—coking coal, petroleum coke, and natural gas—were reallocated to the Industrial Processes chapter, as these portions were actually consumed as raw material during non-energy related industrial processes. Coking coal, also called “coal coke,” is used as a raw material (specifically as a reducing agent) in the blast furnace process to produce iron and steel, 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 carbon anodes and cathodes), and 3) titanium dioxide production (in the chloride process). Finally, natural gas consumption is used for the production of ammonia. Consumption of these fuels for non-energy purposes is presented in the Industrial Processes chapter, and is removed from the energy and non-energy consumption estimates within the Energy chapter.

Second, a portion of industrial coal accounted for in EIA combustion figures is actually used to make “synthetic natural gas” via coal gasification. The energy in this gas enters the natural gas stream, and is accounted for in natural gas consumption statistics. Because this energy is already accounted for as natural gas, it is deducted from industrial coal consumption to avoid double counting. This makes the figure for other industrial coal consumption in this report slightly lower than most EIA sources.

Third, ethanol has been added to the motor gasoline stream for several years, but prior to 1993 this addition was not captured in EIA motor gasoline statistics. Starting in 1993, ethanol was included in gasoline statistics. However, because ethanol is a biofuel, which is assumed to result in no net CO₂ emissions, the amount of ethanol added is subtracted from total gasoline consumption. Thus, motor gasoline consumption statistics given in this report may be slightly lower than in EIA sources.

Fourth, EIA natural gas consumption statistics include “biomass gas,” which is upgraded landfill methane that is sold to pipelines. However, because this gas is biogenic, the biomass gas total is deducted from natural gas consumption. The subtraction is done only from natural gas in the industrial sector, as opposed to all end-sectors, because the biogas amount is small. Due to this adjustment—and the ammonia adjustment mentioned previously—industrial natural gas consumption in this report is slightly lower than in EIA sources.

There are also three basic differences between the consumption figures presented in Table A-1 through Table A-12 and those recommended in the IPCC emission inventory methodology.

First, consumption data in the U.S. inventory are presented using higher heating values (HHV)¹ rather than the lower heating values (LHV)² reflected in the IPCC 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 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 Framework Convention on Climate Change are to include energy consumption within territories. Therefore, consumption estimates for U.S. territories were added to domestic consumption of fossil fuels. Energy consumption data from U.S. territories are presented in Column 7 of Table A-1 through Table A-12. It is reported separately from domestic sectoral consumption, because it is collected separately by EIA with no sectoral disaggregation.

Third, the domestic sectoral consumption data in Table A-1 through Table A-12 include bunker fuels used for international transport activities and non-energy uses of fossil fuels. The IPCC requires countries to estimate emissions from international bunker fuels separately and exclude these emissions from national totals, so international bunker fuel emissions have been estimated in Table A-13 and deducted from national estimates (see Step 4). Similarly, fossil fuels used to produce non-energy products that store carbon rather than release it to the atmosphere are provided in Table A-14 and deducted from national emission estimates (see Step 3). The final fate of these fossil fuel based products is dealt with under the waste combustion source category in cases where the products are combusted through waste management practices.

Step 2: Determine the Carbon Content of All Fuels

The carbon content of combusted fossil fuels was estimated by multiplying energy consumption (Columns 2 through 8 of Table A-1 through Table A-12) by fuel-specific carbon content coefficients (see Table A-15 and Table A-16) that reflect the amount of carbon per unit of energy in each fuel. The resulting carbon contents are sometimes referred to as potential emissions, or the maximum amount of carbon that could potentially be released to the atmosphere if all carbon in the fuels were oxidized. The carbon content coefficients used in the U.S. inventory were derived by EIA from detailed fuel information and are similar to the carbon content coefficients contained in the IPCC's default methodology (IPCC/UNEP/OECD/IEA 1997), with modifications reflecting fuel qualities specific to the United States.

¹ Also referred to as Gross Calorific Values (GCV).

² Also referred to as Net Calorific Values (NCV).

Step 3: Adjust for the amount of Carbon Stored in Products

Depending on the end-use, non-energy uses of fossil fuels can result in long term storage of some or all of the carbon contained in the fuel. For example, asphalt made from petroleum can sequester up to 100 percent of the carbon contained in the petroleum feedstock for extended periods of time. Other non-energy fossil fuel products, such as lubricants or plastics also store carbon, but can lose or emit some of this carbon when they are used and/or burned as waste.³

The amount of carbon in non-energy fossil fuel products was based upon data that addressed the fraction of carbon that remains in products after they are manufactured, with all non-energy use attributed to the industrial, transportation, and territories end-use sectors. This non-energy consumption is presented in Table A-14. These data were then multiplied by fuel-specific carbon content coefficients (Table A-15 and Table A-16) to obtain the carbon content of the fuel, or the maximum amount of carbon that could remain in non-energy products (Column 5 of Table A-14). This carbon content was then multiplied by the fraction of carbon assumed to actually have remained in products (Column 6 of Table A-14), resulting in the final estimates by sector and fuel type, which are presented in Columns 7 and 8 of Table A-14. A detailed discussion of carbon stored in products is provided in the Energy chapter and in Annex C.

Step 4: Subtract Carbon in International Bunker Fuels

Emissions from international transport activities, or international bunker fuel consumption, are not included in national totals, as required by the IPCC (IPCC/UNEP/OECD/IEA 1997). There is currently disagreement internationally as to how these emissions should be allocated, and until this issue is resolved, countries are asked to report them separately. 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. To compensate for this inclusion, international bunker fuel emissions⁴ were calculated separately (see Table A-13) and the carbon content of these fuels was subtracted from the transportation end-use sector. International bunker fuel emissions from military activities were developed using data provided by the Department of Defense as described in the International Bunker Fuels section of the Energy chapter and in Annex J. The calculations of international bunker fuel emissions followed the same procedures used for other fuel emissions (i.e., estimation of consumption, determination of carbon content, and adjustment for the fraction of carbon not oxidized).

Step 5: Account for Carbon that Does Not Oxidize During Combustion

Because combustion processes are not 100 percent efficient, some of the carbon contained in fuels is not emitted in a gaseous form to the atmosphere. Rather, it remains behind as soot, particulate matter and ash. The estimated fraction of carbon not oxidized in U.S. energy conversion processes due to inefficiencies during combustion ranges from 0.5 percent for natural gas to 1 percent for petroleum and coal. Except for coal these assumptions are consistent with the default values recommended by the IPCC (IPCC/UNEP/OECD/IEA 1997). In the United States, unoxidized carbon from coal combustion was estimated to be no more than one percent (Bechtel 1993).

Table A-15 presents fractions oxidized by fuel type, which are multiplied by the net carbon content of the combusted energy to give final emissions estimates.

Of the fraction of carbon that is oxidized (e.g., 99 to 99.5 percent), the vast majority is emitted in its fully oxidized form as carbon dioxide (CO₂). A much smaller portion of this “oxidized” carbon is also emitted as carbon monoxide (CO), methane (CH₄), and non-methane volatile organic compounds (NMVOCs). When in the

³ See Waste Combustion section of the Energy chapter for a discussion of emissions from the combustion of plastics in the municipal solid waste stream.

⁴ Refer to the International Bunker Fuels section of the Energy chapter for a description of the methodology for distinguishing between bunker and non-bunker fuel consumption.

atmosphere, though, these partially oxidized or unoxidized carbon compounds are generally oxidized to CO₂ through atmospheric processes (e.g., reaction with hydroxyl (OH)).⁵

Step 6: Summarize Emission Estimates

Actual CO₂ 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, electricity generation, and U.S. territories). Adjustments for international bunker fuels and carbon in non-energy products were made. Emission estimates are expressed in teragrams of carbon dioxide equivalents (Tg CO₂ Eq.).

To determine total emissions by final end-use sector, emissions from electricity generation were distributed to each end-use sector according to its share of aggregate electricity consumption (see Table A-17). This pro-rated approach to allocating emissions from electricity generation may overestimate or underestimate emissions for particular sectors due to differences in the average carbon content of fuel mixes burned to generate electricity.

⁵ See Indirect CO₂ from CH₄ Oxidation section in Energy chapter for a discussion of proper accounting of carbon from hydrocarbon and CO emissions.

Table A-1: 2001 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Consumption (Tbtu) ^a							Emissions ^b (Tg CO ₂ Eq.) including Adjustments ^c and Fraction Oxidized						
	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	12.0	91.0	1,367.2	NE	19,689.0	9.8	21,169.0	1.1	8.6	126.3	NE	1,856.8	0.9	1,993.8
Residential Coal	12.0						12.0	1.1						1.1
Commercial Coal		91.0					91.0		8.6					8.6
Industrial Coking Coal			14.3				14.3			(0.4)				(0.4)
Industrial Other Coal			1,309.9				1,309.9			122.4				122.4
Coke Imports			43.0				43.0			4.3				4.3
Transportation Coal				NE			NE							NE
Utility Coal					19,689.0		19,689.0					1,856.8		1,856.8
U.S. Territory Coal (bit)						9.8	9.8						0.9	0.9
Natural Gas	4,940.0	3,331.0	8,634.3	642.0	5,397.0	22.8	22,967.2	260.8	175.8	445.5	33.9	284.9	1.2	1,202.1
Total Petroleum	1,472.5	717.9	8,518.3	26,017.7	1,280.0	743.5	38,750.0	101.4	51.4	365.8	1,747.0	100.7	52.3	2,418.6
Asphalt & Road Oil			1,257.6				1,257.6							
Aviation Gasoline				34.9			34.9				2.4			2.4
Distillate Fuel Oil	867.4	470.9	1,150.3	5,442.3	179.7	101.6	8,212.1	62.8	34.1	82.9	388.9	13.0	7.4	589.0
Jet Fuel				3,425.9		65.4	3,491.3				181.5		4.6	186.1
Kerosene	110.6	26.8	12.8			4.0	154.2	7.9	1.9	0.9			0.3	11.0
LPG	494.6	87.3	2,090.2	12.5		9.8	2,694.4	30.7	5.4	68.1	0.8		0.6	105.6
Lubricants			174.3	179.8		1.5	355.6			11.6	12.1		0.1	23.8
Motor Gasoline		46.7	154.3	16,086.1		174.1	16,461.2		3.3	10.8	1,129.3		12.2	1,155.6
Residual Fuel		86.3	226.7	836.0	990.1	129.3	2,268.4		6.7	15.5	32.0	76.5	10.1	140.8
Other Petroleum						257.8	257.8						17.0	17.0
AvGas Blend Components			5.6				5.6			0.4				0.4
Crude Oil														
MoGas Blend Components														
Misc. Products			114.6				114.6			(0.8)				(0.8)
Naphtha (<401 deg. F)			453.1				453.1			10.6				10.6
Other Oil (>401 deg. F)			608.0				608.0			15.6				15.6
Pentanes Plus			241.5				241.5			6.6				6.6
Petroleum Coke			647.1		110.2		757.3			59.7		11.1		70.8
Still Gas			1,346.1				1,346.1			84.0				84.0
Special Naphtha			72.0				72.0			5.2				5.2
Unfinished Oils			(69.2)				(69.2)			(5.1)				(5.1)
Waxes			33.4				33.4			(0.2)				(0.2)
Geothermal					47.1		47.1					0.4		0.4
TOTAL (All Fuels)	6,424.5	4,139.9	18,519.8	26,659.7	26,413.1	776.2	82,933.3	363.3	235.9	937.7	1,780.9	2,242.8	54.4	5,614.9

^a Expressed as gross calorific values (i.e., higher heating values).

^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.

^c Adjustments include: international bunker fuel consumption (see Table A-13) and carbon in non-energy products (see Table A-14).

+ Absolute value does not exceed 0.05 Tg CO₂ Eq.

NE (Not Estimated)

Table A-2: 2000 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Consumption (TBtu) ^a							Emissions ^b (Tg CO ₂ Eq.) including Adjustments ^c and Fraction Oxidized						
	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	12.0	91.0	1,447.4	NE	20,220.0	9.8	21,780.2	1.1	8.6	134.0	NE	1,906.9	0.9	2,051.5
Residential Coal	12.0						12.0	1.1						1.1
Commercial Coal		91.0					91.0		8.6					8.6
Industrial Coking Coal			14.8				14.8			(0.4)				(0.4)
Industrial Other Coal			1,355.6				1,355.6			126.7				126.7
Coke Imports			77.0				77.0			7.8				7.8
Transportation Coal				NE			NE							NE
Utility Coal					20,220.0		20,220.0					1,906.9		1,906.9
U.S. Territory Coal (bit)						9.8	9.8						0.9	0.9
Natural Gas	5,121.0	3,301.3	9,282.2	672.0	5,316.0	11.7	23,704.2	270.3	174.3	478.9	35.5	280.6	0.6	1,240.3
Total Petroleum	1,493.1	718.6	8,899.9	25,764.1	1,144.3	722.6	38,742.6	102.4	51.4	378.2	1,727.3	89.9	50.8	2,400.0
Asphalt & Road Oil			1,275.7				1,275.7							
Aviation Gasoline				36.3			36.3				2.5			2.5
Distillate Fuel Oil	847.5	460.1	1,123.7	5,317.7	174.8	99.1	8,022.9	61.4	33.3	81.0	378.9	12.7	7.2	574.4
Jet Fuel				3,580.4		64.5	3,644.9				192.8		4.5	197.4
Kerosene	103.0	25.0	11.9			3.9	143.7	7.4	1.8	0.9			0.3	10.3
LPG	542.6	95.7	2,293.1	13.7		9.5	2,954.6	33.6	5.9	76.4	0.8		0.6	117.4
Lubricants			189.9	179.4		1.4	370.7			12.7	12.0		0.1	24.7
Motor Gasoline		46.2	152.7	15,749.1		169.2	16,117.2		3.2	10.7	1,105.7		11.9	1,131.5
Residual Fuel		91.6	240.6	887.5	870.8	125.8	2,216.4		7.1	16.6	34.6	67.3	9.8	135.4
Other Petroleum						249.2	249.2						16.5	16.5
AvGas Blend Components			3.8				3.8			0.3				0.3
Crude Oil														
MoGas Blend Components														
Misc. Products			119.3				119.3			+				+
Naphtha (<401 deg. F)			613.9				613.9			17.1				17.1
Other Oil (>401 deg. F)			722.6				722.6			22.0				22.0
Pentanes Plus			343.4				343.4			10.8				10.8
Petroleum Coke			631.3		98.6		729.9			60.9		10.0		70.9
Still Gas			1,449.0				1,449.0			91.5				91.5
Special Naphtha			97.4				97.4			7.0				7.0
Unfinished Oils			(401.4)				(401.4)			(29.5)				(29.5)
Waxes			33.1				33.1			+				+
Geothermal					48.1		48.1					0.4		0.4
TOTAL (All Fuels)	6,626.1	4,110.9	19,629.5	26,436.1	26,728.4	744.2	84,275.2	373.9	234.3	991.1	1,762.7	2,277.8	52.3	5,692.2

^a Expressed as gross calorific values (i.e., higher heating values).^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.^c Adjustments include: international bunker fuel consumption (see Table A-13) and carbon in non-energy products (see Table A-14).+ Absolute value does not exceed 0.05 Tg CO₂ Eq.

NE (Not Estimated)

Table A-3: 1999 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Consumption (Tbtu) ^a							Emissions ^b (Tg CO ₂ Eq.) including Adjustments ^c and Fraction Oxidized						
	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	14.0	103.0	1,419.3	NE	19,279.0	9.8	20,825.1	1.3	9.7	131.7	NE	1,817.5	0.9	1,961.1
Residential Coal	14.0						14.0	1.3						1.3
Commercial Coal		103.0					103.0		9.7					9.7
Industrial Coking Coal			6.3				6.3			(1.2)				(1.2)
Industrial Other Coal			1,342.9				1,342.9			125.8				125.8
Coke Imports			70.0				70.0			7.1				7.1
Transportation Coal				NE			NE							NE
Utility Coal					19,279.0		19,279.0					1,817.5		1,817.5
U.S. Territory Coal (bit)						9.8	9.8						0.9	0.9
Natural Gas	4,858.0	3,129.9	9,040.6	674.0	4,926.0		22,628.5	256.5	165.2	466.4	35.6	260.1		1,183.8
Total Petroleum	1,452.1	654.8	8,961.1	25,178.1	1,211.4	700.4	38,157.8	99.5	46.7	375.0	1,677.5	95.6	49.3	2,343.6
Asphalt & Road Oil			1,324.4				1,324.4							
Aviation Gasoline				39.2			39.2				2.7			2.7
Distillate Fuel Oil	807.2	414.5	1,063.5	5,157.5	140.1	96.4	7,679.3	58.5	30.0	76.6	365.3	10.1	7.0	547.5
Jet Fuel				3,461.8		63.7	3,525.5				184.1		4.5	188.6
Kerosene	111.2	26.9	12.8			3.7	154.7	8.0	1.9	0.9			0.3	11.1
LPG	533.8	94.2	2,255.7	13.4		9.3	2,906.3	33.1	5.8	76.0	0.8		0.6	116.4
Lubricants			192.8	182.1		1.4	376.3			12.9	12.1		0.1	25.1
Motor Gasoline		45.8	151.5	15,658.6		164.0	16,019.9		3.2	10.6	1,098.7		11.5	1,124.1
Residual Fuel		73.3	207.5	665.4	958.7	122.1	2,027.0		5.7	14.0	13.7	74.1	9.5	117.0
Other Petroleum						239.9	239.9						15.8	15.8
AvGas Blend Components			6.4				6.4			0.4				0.4
Crude Oil														
MoGas Blend Components														
Misc. Products			111.9				111.9			+				+
Naphtha (<401 deg. F)			502.0				502.0			14.0				14.0
Other Oil (>401 deg. F)			811.0				811.0			24.7				24.7
Pentanes Plus			364.9				364.9			11.5				11.5
Petroleum Coke			624.9		112.5		737.4			53.4		11.4		64.8
Still Gas			1,436.9				1,436.9			90.5				90.5
Special Naphtha			145.4				145.4			10.5				10.5
Unfinished Oils			(287.9)				(287.9)			(21.1)				(21.1)
Waxes			37.4				37.4			+				+
Geothermal					50.5		50.5					0.4		0.4
TOTAL (All Fuels)	6,324.1	3,887.7	19,421.1	25,852.1	25,466.8	710.2	81,662.0	357.3	221.7	973.2	1,713.0	2,173.5	50.2	5,488.8

^a Expressed as gross calorific values (i.e., higher heating values).

^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.

^c Adjustments include: international bunker fuel consumption (see Table A-13) and carbon in non-energy products (see Table A-14).

+ Absolute value does not exceed 0.05 Tg CO₂ Eq.

NE (Not Estimated)

Table A-4: 1998 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Consumption (Tbtu) ^a							Emissions ^b (Tg CO ₂ Eq.) including Adjustments ^c and Fraction Oxidized						
	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	13.0	92.0	1,483.9	NE	19,216.0	9.8	20,814.7	1.2	8.7	137.8	NE	1,808.7	0.9	1,957.3
Residential Coal	13.0						13.0	1.2						1.2
Commercial Coal		92.0					92.0		8.7					8.7
Industrial Coking Coal			15.4				15.4			(0.3)				(0.3)
Industrial Other Coal			1,388.5				1,388.5			130.0				130.0
Coke Imports			80.0				80.0			8.1				8.1
Transportation Coal				NE			NE							NE
Utility Coal					19,216.0		19,216.0					1,808.7		1,808.7
U.S. Territory Coal (bit)						9.8	9.8						0.9	0.9
Natural Gas	4,669.0	3,098.0	9,410.5	665.0	4,698.0		22,540.5	246.5	163.5	484.1	35.1	248.0		1,177.2
Total Petroleum	1,321.8	658.1	8,772.6	24,457.6	1,306.2	668.2	37,184.5	91.1	47.2	378.2	1,618.8	103.2	47.0	2,285.6
Asphalt & Road Oil			1,262.6				1,262.6							
Aviation Gasoline				35.5			35.5				2.4			2.4
Distillate Fuel Oil	779.9	421.5	1,101.2	4,909.7	135.7	116.5	7,464.4	56.5	30.5	79.3	344.1	9.8	8.4	528.6
Jet Fuel				3,356.8		67.9	3,424.7				180.6		4.8	185.4
Kerosene	108.3	31.2	22.1			6.3	167.8	7.8	2.2	1.6			0.4	12.0
LPG	433.6	76.5	2,048.3	16.6		7.2	2,582.2	26.9	4.7	70.8	1.0		0.4	103.9
Lubricants			190.8	180.2		1.3	372.3			12.7	12.0		0.1	24.8
Motor Gasoline		43.8	199.4	15,285.1		170.0	15,698.3		3.1	14.0	1,072.5		11.9	1,101.5
Residual Fuel		85.2	229.8	673.7	1,047.0	91.9	2,127.6		6.6	15.7	6.2	80.9	7.2	116.6
Other Petroleum						207.1	207.1						13.7	13.7
AvGas Blend Components			4.0				4.0			0.3				0.3
Crude Oil														
MoGas Blend Components														
Misc. Products			119.0				119.0			+				+
Naphtha (<401 deg. F)			584.0				584.0			16.4				16.4
Other Oil (>401 deg. F)			818.7				818.7			25.1				25.1
Pentanes Plus			294.0				294.0			9.3				9.3
Petroleum Coke			625.9		123.6		749.4			57.0		12.5		69.5
Still Gas			1,437.3				1,437.3			91.4				91.4
Special Naphtha			107.3				107.3			7.7				7.7
Unfinished Oils			(313.9)				(313.9)			(23.1)				(23.1)
Waxes			42.4				42.4			+				+
Geothermal					50.5		50.5					0.4		0.4
TOTAL (All Fuels)	6,003.8	3,848.1	19,667.0	25,122.6	25,270.7	678.0	80,590.3	338.8	219.5	1,000.1	1,653.9	2,160.3	47.9	5,420.5

^a Expressed as gross calorific values (i.e., higher heating values).

^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.

^c Adjustments include: international bunker fuel consumption (see Table A-13) and carbon in non-energy products (see Table A-14).

+ Absolute value does not exceed 0.05 Tg CO₂ Eq.

NE (Not Estimated)

Table A-5: 1997 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Consumption (Tbtu) ^a							Emissions ^b (Tg CO ₂ Eq.) including Adjustments ^c and Fraction Oxidized						
	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	16.0	129.0	1,582.3	NE	18,905.0	10.4	20,642.7	1.5	12.1	146.4	NE	1,778.1	0.9	1,939.1
Residential Coal	16.0						16.0	1.5						1.5
Commercial Coal		129.0					129.0		12.1					12.1
Industrial Coking Coal			46.3				46.3			2.4				2.4
Industrial Other Coal			1,479.0				1,479.0			138.3				138.3
Coke Imports			57.0				57.0			5.8				5.8
Transportation Coal				NE			NE							NE
Utility Coal					18,905.0		18,905.0					1,778.1		1,778.1
U.S. Territory Coal (bit)						10.4	10.4						0.9	0.9
Natural Gas	5,118.0	3,302.0	9,592.7	779.0	4,146.0		22,937.7	270.2	174.3	495.8	41.1	218.9		1,200.3
Total Petroleum	1,448.0	703.4	9,103.7	23,930.2	926.8	598.4	36,710.5	100.0	50.6	408.6	1,585.8	73.5	41.8	2,260.3
Asphalt & Road Oil			1,223.6				1,223.6							
Aviation Gasoline				39.7			39.7				2.7			2.7
Distillate Fuel Oil	894.4	443.5	1,116.9	4,728.4	110.6	107.1	7,400.9	64.8	32.1	80.5	333.3	8.0	7.8	526.5
Jet Fuel				3,308.2		64.0	3,372.1				176.2		4.5	180.7
Kerosene	92.9	24.6	18.8			4.0	140.3	6.6	1.8	1.3			0.3	10.0
LPG	460.8	81.3	2,134.1	13.4		7.9	2,697.5	28.6	5.0	74.2	0.8		0.5	109.1
Lubricants			182.3	172.1		2.5	356.9			12.2	11.5		0.2	23.8
Motor Gasoline		42.7	211.9	14,956.7		143.6	15,354.9		3.0	14.9	1,050.6		10.1	1,078.5
Residual Fuel		111.2	290.6	711.7	714.6	60.0	1,888.2		8.7	20.5	10.6	55.2	4.7	99.8
Other Petroleum						209.4	209.4						13.9	13.9
AvGas Blend Components			9.1				9.1			0.6				0.6
Crude Oil			4.6				4.6			0.3				0.3
MoGas Blend Components														
Misc. Products			97.8				97.8			+				+
Naphtha (<401 deg. F)			536.4				536.4			15.3				15.3
Other Oil (>401 deg. F)			861.3				861.3			26.7				26.7
Pentanes Plus			328.9				328.9			10.5				10.5
Petroleum Coke			627.1		101.6		728.6			61.9		10.3		72.1
Still Gas			1,447.2				1,447.2			91.9				91.9
Special Naphtha			72.3				72.3			5.2				5.2
Unfinished Oils			(102.9)				(102.9)			(7.6)				(7.6)
Waxes			43.7				43.7			+				+
Geothermal					50.5		50.5					0.4		0.4
TOTAL (All Fuels)	6,582.0	4,134.4	20,278.7	24,709.2	24,028.3	608.8	80,341.4	371.7	237.1	1,050.8	1,626.9	2,070.8	42.8	5,400.0

^a Expressed as gross calorific values (i.e., higher heating values).

^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.

^c Adjustments include: international bunker fuel consumption (see Table A-13) and carbon in non-energy products (see Table A-14).

+ Absolute value does not exceed 0.05 Tg CO₂ Eq.

NE (Not Estimated)

Table A-6: 1996 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Consumption (Tbtu) ^a							Emissions ^b (Tg CO ₂ Eq.) including Adjustments ^c and Fraction Oxidized						
	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	17.0	122.0	1,573.3	NE	18,429.0	10.3	20,151.6	1.6	11.5	145.3	NE	1,734.0	0.9	1,893.4
Residential Coal	17.0						17.0	1.6						1.6
Commercial Coal		122.0					122.0		11.5					11.5
Industrial Coking Coal			59.7				59.7			3.5				3.5
Industrial Other Coal			1,478.6				1,478.6			138.2				138.2
Coke Imports			35.0				35.0			3.5				3.5
Transportation Coal				NE			NE							NE
Utility Coal					18,429.0		18,429.0					1,734.0		1,734.0
U.S. Territory Coal (bit)						10.3	10.3						0.9	0.9
Natural Gas	5,383.0	3,244.0	9,561.5	736.0	3,883.0		22,807.5	284.2	171.3	494.6	38.9	205.0		1,193.9
Total Petroleum	1,488.6	742.5	8,853.1	23,700.7	817.4	560.0	36,162.1	102.8	53.6	399.6	1,578.5	64.5	39.1	2,238.2
Asphalt & Road Oil			1,175.9				1,175.9							
Aviation Gasoline				37.4			37.4				2.6			2.6
Distillate Fuel Oil	926.6	474.2	1,113.6	4,541.5	109.4	106.3	7,271.5	67.1	34.3	80.3	320.6	7.9	7.7	518.0
Jet Fuel				3,274.2		66.1	3,340.3				177.6		4.6	182.2
Kerosene	88.8	21.0	18.3			3.0	131.1	6.4	1.5	1.3			0.2	9.4
LPG	473.2	83.5	2,088.9	14.7		7.3	2,667.7	29.3	5.2	71.1	0.9		0.5	107.0
Lubricants			172.5	163.0		0.8	336.3			11.5	10.9		0.1	22.4
Motor Gasoline		26.5	199.9	14,818.6		118.6	15,163.7		1.9	14.0	1,041.4		8.3	1,065.7
Residual Fuel		137.2	335.2	851.3	628.4	57.2	2,009.3		10.7	24.1	24.6	48.6	4.5	112.4
Other Petroleum						200.7	200.7						13.3	13.3
AvGas Blend Components			6.9				6.9			0.5				0.5
Crude Oil			13.7				13.7			1.0				1.0
MoGas Blend Components														
Misc. Products			89.0				89.0			+				+
Naphtha (<401 deg. F)			478.9				478.9			13.3				13.3
Other Oil (>401 deg. F)			729.1				729.1			22.2				22.2
Pentanes Plus			354.7				354.7			11.4				11.4
Petroleum Coke			630.1		79.6		709.7			60.5		8.0		68.5
Still Gas			1,435.9				1,435.9			91.3				91.3
Special Naphtha			74.5				74.5			5.4				5.4
Unfinished Oils			(112.7)				(112.7)			(8.3)				(8.3)
Waxes			48.6				48.6			+				+
Geothermal					50.2		50.2					0.4		0.4
TOTAL (All Fuels)	6,888.6	4,108.5	19,987.9	24,436.7	23,179.5	570.3	79,171.4	388.6	236.4	1,039.5	1,617.4	2,003.9	40.1	5,325.8

^a Expressed as gross calorific values (i.e., higher heating values).

^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.

^c Adjustments include: international bunker fuel consumption (see Table A-13) and carbon in non-energy products (see Table A-14).

+ Absolute value does not exceed 0.05 Tg CO₂ Eq.

NE (Not Estimated)

Table A-7: 1995 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Consumption (Tbtu) ^a							Emissions ^b (Tg CO ₂ Eq.) including Adjustments ^c and Fraction Oxidized						
	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	17.0	117.0	1,606.7	NE	17,466.0	10.2	19,216.9	1.6	11.1	148.8	NE	1,643.4	0.9	1,805.8
Residential Coal	17.0						17.0	1.6						1.6
Commercial Coal		117.0					117.0		11.1					11.1
Industrial Coking Coal			50.6				50.6			2.6				2.6
Industrial Other Coal			1,495.1				1,495.1			140.0				140.0
Coke Imports			61.0				61.0			6.2				6.2
Transportation Coal				NE			NE							NE
Utility Coal					17,466.0		17,466.0					1,643.4		1,643.4
U.S. Territory Coal (bit)						10.2	10.2						0.9	0.9
Natural Gas	4,981.0	3,113.0	9,261.0	723.0	4,325.0		22,403.0	263.0	164.3	478.8	38.2	228.3		1,172.6
Total Petroleum	1,356.3	710.2	8,455.9	23,114.8	754.6	605.5	34,997.3	94.0	51.4	374.9	1,539.6	59.7	43.1	2,162.7
Asphalt & Road Oil			1,178.2				1,178.2							
Aviation Gasoline				39.6			39.6				2.7			2.7
Distillate Fuel Oil	877.8	457.2	1,060.3	4,306.4	108.1	125.6	6,935.2	63.6	33.1	76.5	302.8	7.8	9.1	492.8
Jet Fuel				3,132.2		75.5	3,207.7				168.7		5.3	174.0
Kerosene	74.3	22.1	15.4			3.6	115.4	5.3	1.6	1.1			0.3	8.3
LPG	404.2	71.3	2,019.4	16.7		5.6	2,517.3	25.1	4.4	69.2	1.0		0.3	100.1
Lubricants			177.8	167.9		2.0	347.7			11.9	11.2		0.1	23.2
Motor Gasoline		18.1	200.1	14,541.5		148.1	14,907.9		1.3	14.1	1,023.0		10.4	1,048.8
Residual Fuel		141.5	336.7	910.5	566.0	111.9	2,066.6		11.0	24.2	30.2	43.7	8.7	118.0
Other Petroleum						133.2	133.2						8.8	8.8
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			97.0				97.0							
Naphtha (<401 deg. F)			372.6				372.6			10.4				10.4
Other Oil (>401 deg. F)			800.3				800.3			24.4				24.4
Pentanes Plus			337.6				337.6			10.8				10.8
Petroleum Coke			633.6		80.6		714.1			61.5		8.1		69.6
Still Gas			1,416.2				1,416.2			88.0				88.0
Special Naphtha			70.8				70.8			5.1				5.1
Unfinished Oils			(320.6)				(320.6)			(23.5)				(23.5)
Waxes			40.6				40.6							
Geothermal					48.8		48.8					0.4		0.4
TOTAL (All Fuels)	6,354.3	3,940.2	19,323.6	23,837.8	22,594.4	615.7	76,666.0	358.5	226.9	1,002.6	1,577.8	1,931.8	44.0	5,141.5

^a Expressed as gross calorific values (i.e., higher heating values).

^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.

^c Adjustments include: international bunker fuel consumption (see Table A-13) and carbon in non-energy products (see Table A-14).

+ Absolute value does not exceed 0.05 Tg CO₂ Eq.

NE (Not Estimated)

Table A-8: 1994 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Consumption (Tbtu) ^a							Emissions ^b (Tg CO ₂ Eq.) including Adjustments ^c and Fraction Oxidized						
	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	21.0	118.0	1,640.5	NE	17,261.0	10.0	19,050.5	2.0	11.2	151.9	NE	1,621.6	0.9	1,787.6
Residential Coal	21.0						21.0	2.0						2.0
Commercial Coal		118.0					118.0		11.2					11.2
Industrial Coking Coal			37.0				37.0			1.5				1.5
Industrial Other Coal			1,545.5				1,545.5			144.6				144.6
Coke Imports			58.0				58.0			5.9				5.9
Transportation Coal				NE			NE							NE
Utility Coal					17,261.0		17,261.0					1,621.6		1,621.6
U.S. Territory Coal (bit)						10.0	10.0						0.9	0.9
Natural Gas	4,988.0	2,979.0	8,780.4	708.0	4,000.0		21,455.5	263.3	157.3	452.8	37.4	211.2		1,121.9
Total Petroleum	1,333.0	747.0	8,696.8	22,641.3	1,058.8	561.8	35,038.7	92.4	54.3	393.0	1,512.5	82.9	40.8	2,175.8
Asphalt & Road Oil			1,172.9				1,172.9							
Aviation Gasoline				38.1			38.1				2.6			2.6
Distillate Fuel Oil	872.6	460.6	1,095.1	4,168.1	120.1	118.8	6,835.3	63.2	33.4	79.1	293.1	8.7	8.6	486.0
Jet Fuel				3,154.5		65.8	3,220.3				173.2		4.6	177.9
Kerosene	64.9	19.5	16.9			3.0	104.3	4.6	1.4	1.2			0.2	7.5
LPG	395.4	69.8	1,996.5	32.2		7.3	2,501.2	24.5	4.3	68.8	2.0		0.5	100.1
Lubricants			180.9	170.8		1.9	353.6			12.1	11.4		0.1	23.6
Motor Gasoline		25.2	192.4	14,194.9		148.0	14,560.6		1.8	13.6	1,002.2		10.5	1,028.0
Residual Fuel		171.9	418.9	882.6	869.0	164.1	2,506.5		13.4	30.7	27.9	67.2	12.8	152.0
Other Petroleum						53.0	53.0						3.5	3.5
AvGas Blend Components			6.1				6.1			0.4				0.4
Crude Oil			18.7				18.7			1.4				1.4
MoGas Blend Components														
Misc. Products			105.9				105.9			+				+
Naphtha (<401 deg. F)			398.4				398.4			11.0				11.0
Other Oil (>401 deg. F)			838.7				838.7			25.3				25.3
Pentanes Plus			338.7				338.7			12.5				12.5
Petroleum Coke			634.8		69.7		704.5			61.3		7.0		68.4
Still Gas			1,439.5				1,439.5			90.4				90.4
Special Naphtha			81.1				81.1			5.8				5.8
Unfinished Oils			(279.2)				(279.2)			(20.5)				(20.5)
Waxes			40.6				40.6			+				+
Geothermal					45.7		45.7					0.3		0.3
TOTAL (All Fuels)	6,342.0	3,844.0	19,117.7	23,349.4	22,365.5	571.8	75,590.4	357.7	222.7	997.7	1,549.8	1,916.0	41.7	5,085.6

^a Expressed as gross calorific values (i.e., higher heating values).

^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.

^c Adjustments include: international bunker fuel consumption (see Table A-13) and carbon in non-energy products (see Table A-14).

+ Absolute value does not exceed 0.05 Tg CO₂ Eq.

NE (Not Estimated)

Table A-9: 1993 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Consumption (Tbtu) ^a							Emissions ^b (Tg CO ₂ Eq.) including Adjustments ^c and Fraction Oxidized						
	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	24.0	119.0	1,608.2	NE	17,196.0	9.6	18,956.8	2.3	11.3	148.6	NE	1,614.8	0.9	1,777.9
Residential Coal	24.0						24.0	2.3						2.3
Commercial Coal		119.0					119.0		11.3					11.3
Industrial Coking Coal			38.3				38.3			1.5				1.5
Industrial Other Coal			1,542.9				1,542.9			144.3				144.3
Coke Imports			27.0				27.0			2.7				2.7
Transportation Coal				NE			NE							NE
Utility Coal					17,196.0		17,196.0					1,614.8		1,614.8
U.S. Territory Coal (bit)						9.6	9.6						0.9	0.9
Natural Gas	5,095.0	2,942.0	8,740.3	644.0	3,560.0		20,981.3	269.0	155.3	452.9	34.0	187.9		1,099.2
Total Petroleum	1,384.9	749.4	8,295.6	22,040.6	1,123.8	534.1	34,128.4	96.0	54.4	377.6	1,467.4	88.3	38.7	2,122.4
Asphalt & Road Oil			1,149.0				1,149.0							
Aviation Gasoline				38.4			38.4				2.6			2.6
Distillate Fuel Oil	910.7	462.7	1,090.3	3,908.8	86.5	104.9	6,564.0	66.0	33.5	78.7	272.5	6.3	7.6	464.5
Jet Fuel				3,028.0		62.1	3,090.1				165.4		4.4	169.8
Kerosene	75.6	14.0	13.1			3.8	106.5	5.4	1.0	0.9			0.3	7.6
LPG	398.6	70.3	1,794.4	19.0		4.9	2,287.2	24.7	4.4	63.3	1.2		0.3	93.8
Lubricants			173.1	163.5		3.3	339.8			11.5	10.9		0.2	22.7
Motor Gasoline		29.6	179.5	13,981.5		128.3	14,318.8		2.1	12.7	986.1		9.0	1,009.9
Residual Fuel		172.7	445.9	901.5	958.6	155.9	2,634.6		13.5	32.7	28.7	74.1	12.2	161.1
Other Petroleum						71.0	71.0						4.7	4.7
AvGas Blend Components			0.1				0.1			+				+
Crude Oil			21.1				21.1			1.6				1.6
MoGas Blend Components														
Misc. Products			94.7				94.7			+				+
Naphtha (<401 deg. F)			350.5				350.5			9.7				9.7
Other Oil (>401 deg. F)			843.9				843.9			25.5				25.5
Pentanes Plus			332.2				332.2			11.4				11.4
Petroleum Coke			629.3		78.6		707.9			61.7		8.0		69.6
Still Gas			1,429.8				1,429.8			89.4				89.4
Special Naphtha			104.6				104.6			7.5				7.5
Unfinished Oils			(395.9)				(395.9)			(29.1)				(29.1)
Waxes			40.0				40.0			+				+
Geothermal					52.9		52.9					0.4		0.4
TOTAL (All Fuels)	6,503.9	3,810.4	18,644.1	22,684.6	21,932.7	543.7	74,119.4	367.3	221.1	979.2	1,501.4	1,891.5	39.5	4,999.9

^a Expressed as gross calorific values (i.e., higher heating values).

^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.

^c Adjustments include: international bunker fuel consumption (see Table A-13) and carbon in non-energy products (see Table A-14).

+ Absolute value does not exceed 0.05 Tg CO₂ Eq.

NE (Not Estimated)

Table A-10: 1992 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Consumption (Tbtu) ^a							Emissions ^b (Tg CO ₂ Eq.) including Adjustments ^c and Fraction Oxidized						
	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	24.0	118.0	1,592.5	NE	16,466.0	8.8	18,209.3	2.3	11.3	147.0	NE	1,553.5	0.8	1,714.9
Residential Coal	24.0						24.0	2.3						2.3
Commercial Coal		118.0					118.0		11.3					11.3
Industrial Coking Coal			24.9				24.9			(0.5)				(0.5)
Industrial Other Coal			1,532.6				1,532.6			143.9				143.9
Coke Imports			35.0				35.0			3.5				3.5
Transportation Coal				NE			NE							NE
Utility Coal					16,466.0		16,466.0					1,553.5		1,553.5
U.S. Territory Coal (bit)						8.8	8.8						0.8	0.8
Natural Gas	4,835.0	2,890.0	8,583.3	608.0	3,534.0		20,450.3	255.2	152.6	445.3	32.1	186.6		1,071.7
Total Petroleum	1,310.8	810.5	8,436.6	21,780.9	990.7	507.5	33,837.0	90.9	58.9	391.7	1,439.8	77.3	36.7	2,095.3
Asphalt & Road Oil			1,102.2				1,102.2							
Aviation Gasoline				41.1			41.1				2.8			2.8
Distillate Fuel Oil	863.3	463.2	1,135.7	3,808.1	73.5	91.8	6,435.7	62.5	33.5	82.0	265.2	5.3	6.6	455.2
Jet Fuel				3,001.3		61.3	3,062.6				164.2		4.3	168.5
Kerosene	65.0	11.1	9.8			3.3	89.2	4.7	0.8	0.7			0.2	6.4
LPG	382.5	67.5	1,859.8	18.4		11.9	2,340.1	23.7	4.2	65.8	1.1		0.7	95.6
Lubricants			170.0	160.5		1.5	332.0			11.3	10.7		0.1	22.1
Motor Gasoline		79.6	194.2	13,681.5		122.1	14,077.5		5.6	13.7	964.5		8.6	992.4
Residual Fuel		189.1	386.9	1,070.0	872.2	154.6	2,672.7		14.8	27.9	31.2	67.4	12.1	153.3
Other Petroleum						61.2	61.2						4.0	4.0
AvGas Blend Components			0.2				0.2			+				+
Crude Oil			27.4				27.4			2.0				2.0
MoGas Blend Components			75.7				75.7			5.3				5.3
Misc. Products			100.1				100.1			+				+
Naphtha (<401 deg. F)			377.3				377.3			10.4				10.4
Other Oil (>401 deg. F)			815.0				815.0			24.6				24.6
Pentanes Plus			322.7				322.7			19.0				19.0
Petroleum Coke			624.8		45.0		669.9			56.0		4.5		60.6
Still Gas			1,447.8				1,447.8			91.5				91.5
Special Naphtha			104.6				104.6			7.5				7.5
Unfinished Oils			(355.0)				(355.0)			(26.1)				(26.1)
Waxes			37.3				37.3			+				+
Geothermal					57.3		57.3					0.4		0.4
TOTAL (All Fuels)	6,169.8	3,818.5	18,612.4	22,388.9	21,048.0	516.4	72,554.0	348.4	222.8	984.0	1,471.9	1,817.7	37.5	4,882.3

^a Expressed as gross calorific values (i.e., higher heating values).

^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.

^c Adjustments include: international bunker fuel consumption (see Table A-13) and carbon in non-energy products (see Table A-14).

+ Absolute value does not exceed 0.05 Tg CO₂ Eq.

NE (Not Estimated)

Table A-11: 1991 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Consumption (Tbtu) ^a							Emissions ^b (Tg CO ₂ Eq.) including Adjustments ^c and Fraction Oxidized						
	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	23.0	118.0	1,621.3	NE	16,250.0	7.7	18,020.1	2.2	11.3	151.1	NE	1,531.9	0.7	1,697.2
Residential Coal	23.0						23.0	2.2						2.2
Commercial Coal		118.0					118.0		11.3					11.3
Industrial Coking Coal			28.5				28.5			1.4				1.4
Industrial Other Coal			1,582.9				1,582.9			148.8				148.8
Coke Imports			10.0				10.0			1.0				1.0
Transportation Coal				NE			NE							NE
Utility Coal					16,250.0		16,250.0					1,531.9		1,531.9
U.S. Territory Coal (bit)						7.7	7.7						0.7	0.7
Natural Gas	4,697.0	2,813.0	8,247.2	620.0	3,399.0		19,776.2	248.0	148.5	426.4	32.7	179.4		1,035.0
Total Petroleum	1,292.7	859.1	7,973.1	21,434.0	1,198.3	539.8	33,296.9	89.5	62.5	366.0	1,404.3	92.9	38.6	2,053.8
Asphalt & Road Oil			1,076.5				1,076.5							
Aviation Gasoline				41.7			41.7				2.9			2.9
Distillate Fuel Oil	830.9	481.2	1,131.3	3,675.8	83.6	71.4	6,274.2	60.2	34.9	81.7	255.4	6.1	5.2	443.3
Jet Fuel				3,025.0		78.2	3,103.2				166.5		5.5	172.0
Kerosene	72.3	12.1	11.4			2.8	98.6	5.2	0.9	0.8			0.2	7.1
LPG	389.5	68.7	1,749.3	19.9		13.8	2,241.2	24.1	4.3	59.9	1.2		0.9	90.4
Lubricants			166.7	157.5		0.6	324.8			11.1	10.5		+	21.7
Motor Gasoline		85.1	193.3	13,488.3		124.7	13,891.3		6.0	13.6	950.4		8.8	978.8
Residual Fuel		211.9	333.9	1,025.9	1,085.3	134.6	2,791.7		16.5	23.6	17.5	83.9	10.5	152.0
Other Petroleum						113.8	113.8						7.5	7.5
AvGas Blend Components			(0.1)				(0.1)			+				+
Crude Oil			38.9				38.9			2.9				2.9
MoGas Blend Components			(25.9)				(25.9)			(1.8)				(1.8)
Misc. Products			152.6				152.6			+				+
Naphtha (<401 deg. F)			298.9				298.9			8.4				8.4
Other Oil (>401 deg. F)			827.2				827.2			25.2				25.2
Pentanes Plus			294.0				294.0			17.8				17.8
Petroleum Coke			625.8		29.3		655.1			60.0		3.0		63.0
Still Gas			1,426.3				1,426.3			89.5				89.5
Special Naphtha			88.0				88.0			6.3				6.3
Unfinished Oils			(450.1)				(450.1)			(33.0)				(33.0)
Waxes			35.1				35.1			+				+
Geothermal					54.9		54.9					0.4		0.4
TOTAL (All Fuels)	6,012.7	3,790.1	17,841.6	22,054.0	20,902.2	547.5	71,148.1	339.6	222.3	943.5	1,437.1	1,804.7	39.3	4,786.4

^a Expressed as gross calorific values (i.e., higher heating values).

^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.

^c Adjustments include: international bunker fuel consumption (see Table A-13) and carbon in non-energy products (see Table A-14).

+ Absolute value does not exceed 0.05 Tg CO₂ Eq.

NE (Not Estimated)

Table A-12: 1990 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Consumption (Tbtu) ^a							Emissions ^b (Tg CO ₂ Eq.) including Adjustments ^c and Fraction Oxidized						
	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	26.0	129.0	1,632.9	NE	16,245.0	7.0	18,040.0	2.5	12.3	151.6	NE	1,530.3	0.6	1,697.3
Residential Coal	26.0						26.0	2.5						2.5
Commercial Coal		129.0					129.0		12.3					12.3
Industrial Coking Coal			21.0				21.0			0.5				0.5
Industrial Other Coal			1,606.9				1,606.9			150.6				150.6
Coke Imports			5.0				5.0			0.5				0.5
Transportation Coal				NE			NE							NE
Utility Coal					16,245.0		16,245.0					1,530.3		1,530.3
U.S. Territory Coal (bit)						7.0	7.0						0.6	0.6
Natural Gas	4,523.0	2,701.0	8,133.9	680.0	3,321.0		19,358.9	238.8	142.6	419.9	35.9	175.3		1,012.5
Total Petroleum	1,263.1	913.2	8,210.8	21,775.8	1,278.0	461.5	33,902.5	87.6	66.6	383.7	1,434.6	99.0	33.1	2,104.5
Asphalt & Road Oil			1,170.2				1,170.2							
Aviation Gasoline				45.0			45.0				3.1			3.1
Distillate Fuel Oil	834.2	485.3	1,170.6	3,829.4	95.5	74.0	6,489.1	60.4	35.1	84.5	265.9	6.9	5.4	458.2
Jet Fuel				3,129.5		61.0	3,190.5				173.8		4.3	178.1
Kerosene	63.9	11.8	12.3			2.6	90.6	4.6	0.8	0.9			0.2	6.5
LPG	365.0	64.4	1,607.8	21.6		14.4	2,073.3	22.6	4.0	57.1	1.3		0.9	85.9
Lubricants			186.3	176.0		0.7	363.0			12.4	11.7		+	24.2
Motor Gasoline		111.2	185.2	13,559.0		101.0	13,956.4		7.8	13.0	955.3		7.1	983.3
Residual Fuel		240.4	411.2	1,015.4	1,152.9	121.8	2,941.7		18.8	30.2	23.4	89.1	9.5	171.0
Other Petroleum						86.0	86.0						5.7	5.7
AvGas Blend Components			0.2				0.2			+				+
Crude Oil			50.9				50.9			3.7				3.7
MoGas Blend Components			53.7				53.7			3.8				3.8
Misc. Products			137.9				137.9			+				+
Naphtha (<401 deg. F)			347.9				347.9			9.6				9.6
Other Oil (>401 deg. F)			754.2				754.2			22.8				22.8
Pentanes Plus			250.4				250.4			13.4				13.4
Petroleum Coke			626.9		29.6		656.5			58.8		3.0		61.8
Still Gas			1,473.7				1,473.7			92.6				92.6
Special Naphtha			107.1				107.1			7.7				7.7
Unfinished Oils			(369.1)				(369.1)			(27.0)				(27.0)
Waxes			33.3				33.3			+				+
Geothermal					52.9		52.9					0.4		0.4
TOTAL (All Fuels)	5,812.1	3,743.2	17,977.6	22,455.8	20,896.9	468.6	71,354.2	328.9	221.4	955.3	1,470.5	1,805.0	33.7	4,814.8

^a Expressed as gross calorific values (i.e., higher heating values).^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.^c Adjustments include: international bunker fuel consumption (see Table A-13) and carbon in non-energy products (see Table A-14).+ Absolute value does not exceed 0.05 Tg CO₂ Eq.

NE (Not Estimated)

Table A-13: 2001 CO₂ Emissions From International Bunker Fuel Consumption

Fuel Type	Bunker Fuel Consumption (TBtu)	Carbon Content Coefficient (Tg Carbon/QBtu) ¹	Potential Emissions (Tg Carbon)	Fraction Oxidized	Emissions (Tg CO ₂ Eq.)
Distillate Fuel Oil	72	19.95	1.4	0.99	5.2
Jet Fuel	839	19.33	16.2	0.99	58.9
Residual Fuel Oil	426	21.49	9.2	0.99	33.2
Total	1,337		26.8		97.3

Note: See Annex J for additional information on military bunkers.

Table A-14: 2001 Carbon In Non-Energy Products

1	2	3	4	5	6	7	8
Fuel Type	Non-energy Use ^a (TBtu)	Carbon Content Coefficient (Tg Carbon/QBtu)	Potential Carbon (Tg)	Adjusted Potential Carbon ^b (Tg)	Fraction Sequestered	Carbon Stored (Tg)	Carbon Stored (Tg CO ₂ Eq.)
Industry	5,328.6		99.9	98.2		68.1	249.7
Industrial Coking Coal	24.9	25.63	0.6	0.6	0.75	0.5	1.8
Natural Gas	333.9	14.47	4.8	4.7	0.61	2.8	10.4
Asphalt & Road Oil	1,257.6	20.62	25.9	25.9	1.00	25.9	95.1
LPG	1,690.4	16.88	28.5	27.7	0.61	16.8	61.7
Lubricants	174.3	20.24	3.5	3.5	0.09	0.3	1.2
Pentanes Plus	239.2	18.24	4.4	4.2	0.61	2.6	9.5
Petrochemical Feedstocks							
Naphtha (<401 deg. F)	493.7	18.14	9.0	8.7	0.61	5.3	19.4
Other Oil (>401 deg. F)	662.5	19.95	13.2	12.9	0.61	7.8	28.7
Still Gas	31.0	17.51	0.5	0.5	0.80	0.4	1.6
Petroleum Coke	113.2	27.85	3.2	3.2	0.50	1.6	5.8
Special Naphtha	78.5	19.86	1.6	1.6	+	+	+
Other (Wax/Misc.)							
Distillate Fuel Oil	11.7	19.95	0.2	0.2	0.50	0.1	0.4
Residual Fuel	56.6	21.49	1.2	1.2	0.50	0.6	2.2
Waxes	36.3	19.81	0.7	0.7	1.00	0.7	2.6
Miscellaneous	124.9	20.29	2.5	2.5	1.00	2.5	9.3
Transportation	164.6		3.3	3.3		0.3	1.1
Lubricants	164.6	20.24	3.3	3.3	0.09	0.3	1.1
U.S. Territories	259.3		5.2	5.2		0.5	1.9
Lubricants	1.5	20.24	+	+	0.09	+	+
Other Petroleum (Misc.)	257.8	20.00	5.2	5.2	0.10	0.52	1.9
Total	5,752.5		108.5	106.7		68.9	252.8

^a To avoid double-counting, the original values reported by EIA for coal coke, petroleum coke, and natural gas consumption are adjusted for industrial process consumption. Values in this column reflect these adjustments.

^b Natural gas, LPG, Pentanes Plus, Naphthas, and Other Oils are adjusted to account for exports of chemical intermediates derived from these fuels. Values in this column reflect these adjustments.

+ Does not exceed 0.05 Tg or Tg CO₂ Eq.

¹ One QBtu is one quadrillion Btu, or 10¹⁵ Btu. This unit is commonly referred to as a "Quad."

Table A-15: Key Assumptions for Estimating Carbon Dioxide Emissions

Fuel Type	Carbon Content Coefficient (Tg Carbon/QBtu)	Fraction Oxidized
Coal		
Residential Coal	[a]	0.99
Commercial Coal	[a]	0.99
Industrial Coking Coal	[a]	0.99
Industrial Other Coal	[a]	0.99
Coke Imports	27.85	0.99
Transportation Coal	NC	NC
Utility Coal	[a]	0.99
U.S. Territory Coal (bit)	25.14	0.99
Natural Gas	14.47	0.995
Petroleum		
Asphalt & Road Oil	20.62	0.99
Aviation Gasoline	18.87	0.99
Distillate Fuel Oil	19.95	0.99
Jet Fuel	[a]	0.99
Kerosene	19.72	0.99
LPG	[a]	0.995
LPG (energy use/Territories)	[a]	0.995
LPG (non-energy use)	[a]	-
Lubricants	20.24	0.99
Motor Gasoline	[a]	0.99
Residual Fuel Oil	21.49	0.99
Other Petroleum		
AvGas Blend Components	18.87	0.99
Crude Oil	[a]	0.99
MoGas Blend Components	[a]	0.99
Misc. Products	[a]	0.99
Misc. Products (Territories)	20.00	0.99
Naphtha (<401 deg. F)	18.14	0.99
Other Oil (>401 deg. F)	19.95	0.99
Pentanes Plus	18.24	0.99
Petrochemical Feedstocks	19.37	0.99
Petroleum Coke	27.85	0.99
Still Gas	17.51	0.99
Special Naphtha	19.86	0.99
Unfinished Oils	[a]	0.99
Waxes	19.81	0.99
Geothermal	2.05	1.00

Sources: Carbon coefficients from EIA. Combustion efficiency for coal from Bechtel (1993) and for petroleum and natural gas from IPCC (IPCC/UNEP/OECD/IEA 1997).

- Not applicable

NC (Not Calculated)

[a] These coefficients vary annually due to fluctuations in fuel quality (see Table A-16).

Table A-16: Annually Variable Carbon Content Coefficients by Year (Tg Carbon/QBtu)

Fuel Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Residential Coal	26.23	26.30	26.42	26.19	26.12	26.16	26.06	25.93	26.09	26.02	26.04	26.04
Commercial Coal	26.23	26.30	26.42	26.19	26.12	26.16	26.06	25.93	26.09	26.02	26.04	26.04
Industrial Coking Coal	25.55	25.56	25.55	25.53	25.57	25.57	25.56	25.60	25.62	25.60	25.63	25.63
Industrial Other Coal	25.82	25.89	25.87	25.77	25.77	25.80	25.75	25.76	25.79	25.80	25.74	25.74
Utility Coal	25.95	25.97	25.99	25.87	25.88	25.92	25.92	25.91	25.93	25.97	25.98	25.98
LPG	16.99	16.98	16.99	16.97	17.01	17.00	16.99	16.99	16.99	16.99	16.99	16.99
LPG (energy use/Territories)	17.21	17.21	17.21	17.22	17.22	17.20	17.20	17.18	17.18	17.18	17.18	17.18
LPG (non-energy use)	16.83	16.84	16.84	16.80	16.88	16.87	16.86	16.88	16.87	16.88	16.87	16.88
Motor Gasoline	19.41	19.41	19.42	19.43	19.45	19.38	19.36	19.35	19.33	19.33	19.34	19.34
Jet Fuel	19.40	19.40	19.39	19.37	19.35	19.34	19.33	19.33	19.33	19.33	19.33	19.33
MoGas Blend Components	19.41	19.41	19.42	19.43	19.45	19.38	19.36	19.35	19.33	19.33	19.34	19.34
Misc. Products	20.16	20.18	20.22	20.22	20.21	20.23	20.25	20.24	20.24	20.19	20.23	20.29
Unfinished Oils	20.16	20.18	20.22	20.22	20.21	20.23	20.25	20.24	20.24	20.19	20.23	20.29
Crude Oil	20.16	20.18	20.22	20.22	20.21	20.23	20.25	20.24	20.24	20.19	20.23	20.29

Source: EIA (2002a) and EIA (2001b)

Table A-17: Electricity Consumption by End-Use Sector (Billion Kilowatt-Hours)

End-Use Sector	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Residential	924	955	936	995	1,008	1,043	1,083	1,076	1,130	1,145	1,192	1,201
Commercial	838	855	850	885	913	953	980	1,027	1,078	1,104	1,159	1,196
Industrial	1,060	1,065	1,095	1,105	1,142	1,157	1,179	1,187	1,212	1,241	1,248	1,199
Transportation	5	5	5	5	5	5	5	5	5	5	5	6
U.S. Territories*	-	-	-	-	-	-	-	-	-	-	-	-
Total	2,827	2,880	2,886	2,989	3,069	3,157	3,247	3,294	3,425	3,495	3,605	3,602

*EIA data on fuel consumption for electricity generation does not include the U.S. territories.

- Not applicable

Source: EIA (2002a)

ANNEX B

Methodology for Estimating the Carbon Content of Fossil Fuels

This annex presents the background and methodology for estimating the carbon content of fossil fuels combusted in the United States. The carbon content of a particular fossil fuel represents the maximum potential emissions to the atmosphere if all carbon in the fuel is oxidized during combustion. The carbon content coefficients used in this report were developed using methods first outlined in EIA's *Emissions of Greenhouse Gases in the United States: 1987-1992* (1994) and were developed primarily by EIA. This annex describes an updated methodology for estimating the carbon content of coal, and presents a time-series analysis of changes in U.S. carbon content coefficients. A summary of carbon content coefficients used in this report appears in Table B-1.

Though the methods for estimating carbon contents for coal, natural gas, and petroleum products differ in their details, they each follow the same basic approach. First, because carbon coefficients are presented in terms of mass per unit energy (i.e., teragrams carbon per quadrillion Btu or Tg/QBtu), those fuels that are typically described in volumetric units (petroleum products and natural gas) are converted to units of mass using an estimated density. Second, carbon contents are derived from fuel sample data, using descriptive statistics to estimate the carbon 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 carbon content of coal is described first because approximately one-third of all U.S. carbon emissions from fossil fuel combustion are associated with coal consumption. The methods and sources for estimating the carbon content of natural gas are provided next. Approximately one-fifth of U.S. greenhouse gas emissions from fossil fuel combustion are attributable to natural gas consumption. Finally, this annex examines carbon contents of petroleum products. U.S. energy consumption statistics account for more than 20 different petroleum products.

Table B-1: Carbon Content Coefficients Used in this Report (Tg Carbon/QBtu)

Fuel Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Coal												
Residential Coal*	26.23	26.30	26.42	26.19	26.12	26.16	26.06	25.93	26.09	26.02	26.04	26.04 ^P
Commercial Coal*	26.23	26.30	26.42	26.19	26.12	26.16	26.06	25.93	26.09	26.02	26.04	26.04 ^P
Industrial Coking Coal*	25.55	25.56	25.55	25.53	25.57	25.57	25.56	25.60	25.62	25.60	25.63	25.63 ^P
Industrial Other Coal*	25.82	25.89	25.87	25.77	25.77	25.80	25.75	25.76	25.79	25.80	25.74	25.74 ^P
Utility Coal*	25.95	25.97	25.99	25.87	25.88	25.92	25.92	25.91	25.93	25.97	25.98	25.98 ^P
Natural Gas	14.47	14.47	14.47	14.47	14.47	14.47	14.47	14.47	14.47	14.47	14.47	14.47
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
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
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
Jet Fuel*	19.40	19.40	19.39	19.37	19.35	19.34	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
LPG*	16.99	16.98	16.99	16.97	17.01	17.00	16.99	16.99	16.99	16.99	16.99	16.99
LPG (Territories)*	17.21	17.21	17.21	17.22	17.22	17.20	17.20	17.18	17.18	17.18	17.18	17.18
LPG (non-energy use)*	16.83	16.84	16.84	16.80	16.88	16.87	16.86	16.88	16.87	16.88	16.87	16.88
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
Motor Gasoline*	19.41	19.41	19.42	19.43	19.45	19.38	19.36	19.35	19.33	19.33	19.34	19.34
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
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
Crude Oil	20.16	20.18	20.22	20.22	20.21	20.23	20.25	20.24	20.24	20.19	20.23	20.29
Misc. Products	20.16	20.18	20.22	20.22	20.21	20.23	20.25	20.24	20.24	20.19	20.23	20.29
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
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
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
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
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

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
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
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
Unfinished Oils	20.16	20.18	20.22	20.22	20.21	20.23	20.25	20.24	20.24	20.19	20.23	20.29
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
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
Geothermal	2.05	2.05	2.05	2.05	2.05	2.05	2.05	2.05	2.05	2.05	2.05	2.05

*Carbon contents vary annually based on changes in fuel composition.

p Preliminary

All coefficients based on higher heating value.¹

Coal

Approximately one-third of all U.S. carbon dioxide emissions from fossil fuel combustion are associated with coal consumption. Although the IPCC guidelines provide carbon contents for coal according to rank, it was necessary to develop carbon content coefficients by consuming sector to match the format in which coal consumption is reported by EIA. Because the carbon 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 carbon content for coal combusted in each consuming sector also varies over time. A time series of carbon contents by coal rank and consuming sector appears in Table B-2.²

Table B-2: Carbon Content Coefficients for Coal by Consuming Sector and Coal Rank (Tg/QBtu) (1990-2001)

Consuming Sector	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Electric Power	25.95	25.97	25.99	25.87	25.88	25.92	25.92	25.91	25.93	25.97	25.98	25.98 ^p
Industrial Coking	25.55	25.56	25.55	25.53	25.57	25.57	25.56	25.60	25.62	25.60	25.63	25.63 ^p
Other Industrial	25.82	25.89	25.87	25.77	25.77	25.80	25.75	25.76	25.79	25.80	25.74	25.74 ^p
Residential/Commercial	26.23	26.30	26.42	26.19	26.12	26.16	26.06	25.93	26.09	26.02	26.04	26.04 ^p
Coal Rank												
Anthracite	28.26	28.26	28.26	28.26	28.26	28.26	28.26	28.26	28.26	28.26	28.26	28.26 ^p
Bituminous	25.43	25.45	25.44	25.45	25.46	25.47	25.47	25.48	25.47	25.48	25.49	25.49 ^p
Sub-bituminous	26.50	26.49	26.49	26.48	26.49	26.49	26.49	26.49	26.49	26.49	26.48	26.48 ^p
Lignite	26.19	26.21	26.22	26.21	26.24	26.22	26.17	26.20	26.23	26.26	26.30	26.30 ^p

p Preliminary

Sources: USGS (1998) and SAIC (2002).

Methodology

The methodology for developing carbon contents for coal by consuming sector consists of four steps.

Step 1. Determine carbon contents by rank and by state of origin

Carbon contents by rank are estimated on the basis of 6,588 coal samples collected by the U.S. Geological Survey between 1973 and 1989. These coal samples are classified according to rank and state of origin. For each rank in each state, the average heat content and carbon content of the coal samples are calculated. Dividing the carbon content (reported in pounds carbon dioxide) by the heat content (reported in million Btu or MMBtu) yields an average carbon content coefficient. This coefficient is then converted into units of Tg/QBtu.

¹ 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 carbon dioxide 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.

² For a comparison to earlier estimated carbon contents please see *Chronology and Explanation of Changes in Individual Carbon Content Coefficients of Fossil Fuels* near the end of this annex.

Step 2. Allocate sectoral consumption by rank and state of origin

U.S. energy statistics 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. 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.

Step 3. Weight sectoral carbon contents to reflect the rank and state of origin of coal consumed

Sectoral carbon contents are calculated by multiplying the share of coal purchased from each state by rank by the carbon content estimated in Step 1. The resulting partial carbon contents are then totaled across all states and ranks to generate a national sectoral carbon content.

$$C_{\text{sector}} = \sum S_{\text{rank}1} * C_{\text{rank}1} + S_{\text{rank}2} * C_{\text{rank}2} + \dots S_{\text{rank}50} * C_{\text{rank}50}$$

Where:

C_{sector} is the carbon content by consuming sector;

S_{rank} is the portion of consuming sector coal consumption attributed to a given rank in each state; and

C_{rank} is the estimated carbon content of a given rank in each state.

Step 4. Develop national-level carbon contents by rank for comparison to IPCC defaults

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

$$N_{\text{rank}} = \sum P_{\text{rank}1} * C_{\text{rank}1} + P_{\text{rank}2} * C_{\text{rank}2} + \dots P_{\text{rank}n} * C_{\text{rank}n}$$

Where:

N_{rank} is the national carbon content by rank;

P_{rank} is the portion of U.S. coal production attributed to a given rank in each state; and

C_{rank} is the estimated carbon content of a given rank in each state.

Data Sources

The ultimate analyses of coal samples was based on the 6,588 coal samples from the U.S. Geological Survey, CoalQual Database Version 2.0 (1998). Data contained in the CoalQual Database are derived primarily from samples taken between 1973 and 1989, and were largely reported in State Geological Surveys.

Data on coal distribution by state and consumption by sector, as well as coal production by state and rank, was obtained from EIA's *Coal Industry Annual* (2002a).

Uncertainty

Carbon contents vary considerably by state. Bituminous coal production and sub-bituminous coal production represented 53.4 percent and 38.1 percent of total U.S. supply in 2000, respectively. Carbon content coefficients for bituminous coal vary from a low of 200.5 pounds carbon dioxide per MMBtu in Kansas to a high of 232.0 pounds carbon dioxide per MMBtu in Montana. In 2000, however, just 200 tons of bituminous coal were produced in Kansas, and none were produced in Montana. In 2000, more than 60 percent of bituminous coal was produced in three states: West Virginia, Kentucky, and Pennsylvania, and this share has remained fairly constant

since 1990. These three states show a variation in carbon content for bituminous coals of ± 0.7 percent, based on more than 2,000 samples (See Table B-3).

Similarly, the carbon content coefficients for sub-bituminous coal range from 201.3 pounds carbon dioxide per MMBtu in Utah to 217.5 pounds carbon dioxide per MMBtu in Washington. Utah showed no sub-bituminous coal production in 2000, and Washington produced just 4,000 tons. Wyoming, however, has represented between 75 percent and 82 percent of total sub-bituminous coal production in the United States since 1990. Thus, the carbon content coefficient for Wyoming, based on 435 samples, dominates.

The interquartile range of carbon 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 ± 1.0 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 for U.S. coal suggest that the uncertainty in this factor is very low, on the order of ± 1.0 percent.

Table B-3: Variability in Carbon Content Coefficients by Rank Across States (Kilograms Carbon Dioxide Per MMBtu)

State	Number of Samples	Bituminous	Sub-bituminous	Anthracite	Lignite
Alabama	946	92.85	-	-	99.11
Alaska	90	98.34	98.11	-	98.66
Arizona	11	-	97.52	-	-
Arkansas	70	96.52	-	-	94.98
Colorado	292	94.39	96.48	-	96.48
Georgia	35	95.03	-	-	-
Idaho	1	-	94.89	-	-
Illinois	16	93.35	-	-	-
Indiana	125	92.67	-	-	-
Iowa	89	91.94	-	-	-
Kansas	28	90.94	-	-	-
Kentucky	870	92.58	-	-	-
Louisiana	1	-	-	-	96.03
Maryland	46	94.35	-	-	-
Massachusetts	3	-	-	114.82	-
Michigan	3	92.85	-	-	-
Mississippi	8	-	-	-	98.20
Missouri	91	91.85	-	-	-
Montana	301	105.23	97.75	103.60	99.38
Nevada	2	94.39	-	-	99.84
New Mexico	167	95.25	94.89	103.92	-
North Dakota	186	-	-	-	99.56
Ohio	646	91.85	-	-	-
Oklahoma	46	92.67	-	-	-
Pennsylvania	739	93.39	-	103.65	-
Tennessee	58	92.80	-	-	-
Texas	48	-	-	-	94.76
Utah	152	96.07	91.31	-	-
Virginia	456	93.53	-	98.52	-
Washington	14	95.39	98.66	102.51	106.55
West Virginia	566	93.89	-	-	-
Wyoming	476	94.66	97.20	-	-

- No Sample Data Available

Sources: USGS (1998) and SAIC (2002).

Natural Gas

Natural gas is predominantly composed of methane, which is 75 percent carbon by weight and contains 14.2 Tg C/QBtu (Higher Heating Value), but it may also contain many other compounds that can lower or raise its overall carbon 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 (C₂H₆), propane (C₃H₈), butane (C₄H₁₀), and, to a lesser extent, pentane (C₅H₁₂) and hexane (C₆H₁₄). Because the NGLs have more carbon atoms than methane (which has only one), their presence increases the overall carbon content of natural gas. NGLs have a commercial

value greater than that of methane, 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 gasoline³ 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 carbon dioxide, 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. Otherwise, inert gases will usually be left in the natural gas. Because the raw gas that is usually flared contains NGLs and carbon dioxide, it will typically have a higher overall carbon content than gas that has been processed and moved to end-use customers via transmission and distribution pipelines.

Methodology

The methodology for estimating the carbon contents of natural gas can be described in five steps.

Step 1. Define pipeline-quality natural gas

In the United States, pipeline-quality natural gas is expected 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 methane, 3 percent NGLs, and 2 percent non-hydrocarbon gases, of which approximately 1 percent is carbon dioxide.

However, there is a range of gas compositions that are consistent with pipeline specifications. The minimum carbon content coefficient for natural gas would match that for pure methane, 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 carbon emissions factors, because the "low" Btu gas has a higher content of inert gases (including carbon dioxide 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 carbon dioxide). All natural gas flared for these reasons is probably "rich" associated gas, with relatively high energy content, high NGL content, and a high carbon 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 energy content of 1,130 Btu per standard cubic foot. 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.

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

A relationship between carbon content and heat content may be used to develop a carbon content coefficient for natural gas consumed in the United States. In 1994, EIA examined the composition (and therefore

³ 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.

carbon 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 1,025 Btu per cubic foot, varying by less than 1 percent (1,025 to 1,031 Btu per cubic foot) over the past 5 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 U.S. The average and median composition of these samples appears in Table B-4.

Table B-4. 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	1,032

Source: Gas Technology Institute (1992)

Carbon contents were then calculated for a series of sub samples stratified by heat content. Carbon contents were developed for eight separate sub-samples based on heat content and are shown in Table B-5.

Table B-5. Carbon Content of Pipeline-Quality Natural Gas by Energy Content (Tg/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).

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

Because there is some regional variation in the energy content of natural gas consumed, a weighted national average carbon content was calculated using the average carbon contents for each sub-sample of gas that conformed with an individual state's typical cubic foot of natural gas. The result was a weighted national average of 14.47 Tg/QBtu. This was identical to the average carbon content of all samples with more than 1,000 Btu per cubic foot and the average carbon content for all samples with a heat content between 1,025 and 1,050 Btu per cubic foot. Because those samples with a heat content below 1,000 Btu had an unusually high carbon content coefficient attributable to large portions of carbon dioxide (not seen in the median sample), they were excluded so as not to bias the carbon content coefficient upwards by including them in the final sample used to select a carbon content.

Step 5. Apply carbon content coefficients developed in Step 3 to flare gas

Selecting a carbon content coefficient for flare gas was much more difficult than for pipeline natural gas because of the uncertainty of its composition and uncertainty of the combustion efficiency of the flare. Because EIA estimates the heat content of flare gas at 1,130 Btu per cubic foot, the average carbon content for samples with more than 1,100 Btu per cubic foot, 14.92 Tg/QBtu, was adopted as the coefficient for flare gas. It should be noted that the sample data set did not include any samples with more than 1,130 Btu per cubic foot.

Data Sources

Natural gas samples were obtained from the Gas Technology Institute (formerly Gas Research Institute) database (1992) as documented in W.E. Liss, W.H. Thrasher, G.F. Steinmetz, P. Chowdiah, and A. Atari, *Variability of Natural Gas Composition in Select Major Metropolitan Areas of the United States*.

Average heat content of natural gas consumed in the United States was taken from Table A4 of EIA's *Monthly Energy Review* (2002).

Data on the average heat content consumed, on a state-by-state basis, was obtained from the U.S. Department of Energy, U.S. Energy Information Administration, *State Energy Data Report 1999*, Tables 1 and 2 (2001c). Available online at <www.eia.doe.gov/emeu/sedr/contents.html#PDF%20Files>.

Uncertainty

The assignment of carbon content coefficients for natural gas, and particularly for flare gas, requires more subjective judgment than the methodology used for coal. This subjective judgment may introduce additional uncertainty.

Figure B-1 shows the relationship between the calculated carbon contents for each natural gas sample and its energy content. This figure illustrates the relatively restricted range of variation in both the energy content (which varies by about 6 percent from average) and the carbon emission coefficient of natural gas (which varies by about 5 percent). Thus, the knowledge that gas has been sold via pipeline to an end-use consumer allows its carbon emission coefficient to be predicted with an accuracy of ± 5.0 percent.

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

Source: EIA (1994).

Natural gas suppliers may achieve the same energy contents with a wide variety of methane, higher hydrocarbon, and non-hydrocarbon gas combinations. Thus, the plot reveals large variations in carbon content for a single Btu value. In fact, the variation in carbon 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 carbon content coefficient beyond the ± 5.0 percent offered with the knowledge that it is of pipeline-quality.

The plot of carbon 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 methane. 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 carbon dioxide as one of the inert gases and, consequently, also tend to have higher emission coefficients (see left side of Figure B-1).

For the full sample (N=6,743), the average carbon content of a cubic foot of gas was 14.51 Tg/QBtu (see Table B-5). However, this average was raised by both the samples with less than 1,000 Btu per cubic foot 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 weighted national average of 14.47 Tg/QBtu that represents fuels more typically consumed is used.⁴

Petroleum

There are four critical determinants of the carbon 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.

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

Where:

C_{fuel} is the carbon content coefficient of the fuel;

D_{fuel} is the density of the fuel;

S_{fuel} is the share of the fuel that is carbon; and

E_{fuel} is the heat content of the fuel.

Petroleum products vary between 5.6 degrees API gravity (dense products such as asphalt and road oil) and 247 degrees (ethane).⁵ This is a range in density of 60 to 150 kilograms per barrel, or ± 50 percent. The variation in

⁴ The national average was weighted by applying the carbon content associated with the average heat content of natural gas consumed in each state by the portion of national natural gas consumption represented by that state.

⁵ 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

carbon content, however, is much smaller (± 5 to 7 percent): ethane is 80 percent carbon by weight, while petroleum coke is 90 to 92 percent carbon. The tightly bound range of carbon contents can be explained by basic petroleum chemistry.

Petroleum Chemistry

Crude oil and petroleum products are typically mixtures of several hundred distinct compounds, predominantly hydrocarbons. All hydrocarbons contain hydrogen and carbon 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 carbon atoms in each molecule. Petroleum products consisting of relatively simple molecules and few carbon atoms have low boiling temperatures, while larger molecules with more carbon atoms have higher boiling temperatures.

Products that boil off at higher temperatures are usually more dense, which implies greater carbon content as well. Petroleum products with higher carbon contents, in general, have lower energy content per unit mass and higher energy content per unit volume than products with lower carbon contents. Empirical research led to the establishment of a set of quantitative relationships between density, energy content per unit weight and volume, and carbon and hydrogen content. Figure B-2 compares carbon content coefficients calculated on the basis of the derived formula with actual carbon 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 B-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 Guthrie (1960). 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 DOC (1929), and relationship between energy content and fuel composition in Ringen et al. (1979).

The derived empirical relationship between carbon content per unit heat and density is based on the types of hydrocarbons most frequently encountered. Actual 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 carbon 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 carbon content of heavy fuel oils can often be several percent lower than that of lighter fuels, due entirely to the presence of non-hydrocarbons.

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: $\text{API Gravity} = (141.5/\text{Specific Gravity}) - 131.5$. 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.

Variations in Hydrocarbon Classes

Hydrocarbons can be divided into five general categories, each with a distinctive relationship between density and carbon 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 carbon content of the paraffins increases with their carbon number: ethane is 80 percent carbon by weight, octane 84 percent. As the size of paraffin molecules increases, the carbon content approaches the limiting value of 85.7 percent asymptotically (See Figure B-3).

Cycloparaffins. Cycloparaffins are similar to paraffins, except that the carbon 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 85.7 percent carbon by mass, regardless of molecular size.

Olefins. Olefins are a reactive and unstable form of paraffin: a straight chain with the two hydrogen atoms at each end of the chain missing. They are never found in crude oil but are created in moderate quantities by the refining process. Thus, gasoline, for example, may contain 2 percent olefins. They also have the general formula C_nH_{2n} , and hence are also always 85.7 percent carbon 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 steam reforming of naphtha. Aromatics also take the form of ring structures with some double bonds between carbon 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 percent carbon by mass, while xylene is 90.6 percent carbon by mass. Unlike the other hydrocarbon families, the carbon content of aromatics declines asymptotically toward 85.7 percent with increasing carbon number and density. (See Figure B-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 94.4 percent carbon by mass) and anthracene ($C_{14}H_{10}$ and 97.7 percent carbon). They are relatively rare but do appear in heavier petroleum products.

Figure B-3 illustrates the share of carbon by weight for each class of hydrocarbon. Hydrocarbon molecules containing 2 to 4 carbon atoms are all natural gas liquids; hydrocarbons with 5 to 10 carbon atoms are predominantly found in naphtha and gasoline; and hydrocarbon compounds with 12 to 20 carbons comprise "middle distillates," which are used to make diesel fuel, kerosene and jet fuel. Larger molecules are generally used as lubricants, waxes, and residual fuel oil.

Figure B-3. Carbon Content of Pure Hydrocarbons as a Function of Carbon Number

Source: Hunt (1979).

If one knows nothing about the composition of a particular petroleum product, assuming that it is 85.7 percent carbon by mass is not an unreasonable first approximation. Since denser products have higher carbon numbers, this guess would be most likely to be correct for crude oils and fuel oils. The carbon 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 20 separate petroleum products and product categories. The carbon contents, heat contents, and density for each product are provided below in Table B-6. A description of the methods and data sources for estimating the key parameters for each individual petroleum product appears below.

Table B-6. Carbon Content Coefficients and Underlying Data for Petroleum Products

Fuel	2001 Carbon Content (Tg/QBtu)	Gross Heat of Combustion (MMBtu/Barrel)	Density (API Gravity)	Percent Carbon
Motor Gasoline	19.34	5.253	59.6	86.60
LPG	16.99	a	a	a
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 ^b	67.1 ^b	84.11 ^b
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	20.29	5.800	30.5	85.49
Unfinished Oils	20.29	5.825	30.5	85.49
Miscellaneous Products	20.29	5.796	30.5	85.49
Pentanes Plus	18.24	4.620	81.7	83.70
Natural Gasoline	18.24	4.620	81.7	83.70

a LPG is a blend of multiple paraffinic hydrocarbons: ethane, propane, isobutane, and normal butane, each with their own heat content, density and carbon content, see Table B-9.

b 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.

- No sample data available

Sources: EIA (1994) and SAIC (2002).

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.⁶ “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 20 percent of all U.S. carbon dioxide emissions. EIA collects consumption data (i.e., “petroleum products supplied” by wholesalers) for several types of gasoline: leaded regular, unleaded regular, and unleaded high octane. 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, which implies a range of possible carbon and energy contents per barrel. Table B-7 reflects changes in the density of gasoline over time and across grades of gasoline through 2001.

Table B-7. Motor Gasoline Density, 1990 – 2001 (Degrees API)

Fuel Grade	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Winter Grade												
Low Octane	62.0	61.8	61.4	61.0	60.1	59.8	60.6	61.5	61.8	61.6	61.6	61.7
Mid Octane	60.8	60.4	60.2	59.9	59.4	59.1	59.9	60.7	61.2	61.3	61.2	61.2
High Octane	59.0	59.3	59.0	58.7	58.5	58.0	58.5	59.3	60	60.3	59.7	59.1
Summer Grade												
Low Octane	58.2	58.0	57.4	56.1	55.7	56.1	56.9	57.1	57.6	57.7	56.8	57.2
Mid Octane	57.4	57.1	56.4	55.5	54.8	55.6	56.2	56.6	56.7	57.4	58.0	58.0
High Octane	55.5	55.7	55.6	54.4	53.8	55.1	55.3	56.4	55.7	57.4	55.8	55.5

Source: National Institute of Petroleum and Energy Research (1990 through 2001).

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 used in gasoline increased. As discussed above, aromatic hydrocarbons have a lower ratio of hydrogen to carbon 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. In reformulated gasoline, methyl tertiary butyl ether (MTBE) and tertiary amyl methyl ether (TAME) are often added to standard gasoline to boost its oxygen content. The increased oxygen reduces the emissions of carbon monoxide and unburned hydrocarbons. These oxygen-rich blending components are also much lower in carbon than standard gasoline. The average gallon of reformulated gasoline consumed in 2001 contained 8 percent MTBE and 0.5 percent TAME. The characteristics of reformulated fuel additives appear in Table B-8.

Table B-8. Characteristics of Major Reformulated Fuel Additives

Additive	Density (Degrees API)	Carbon Share (Percent)	Carbon Content (Tg/QBtu)
MTBE	59.1	68.2	16.92
ETBE	59.1	70.5	17.07
TAME	52.8	70.5	17.00

Source: API (1988).

Methodology

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

U.S. gasoline consumption was divided by product grade and season for both standard gasoline and reformulated gasoline.

⁶ 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.

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

Carbon content coefficients for each grade and type are derived from three parameters: gasoline density, share of the gasoline mixture that is carbon; and the energy content of a gallon of gasoline. Carbon content coefficients for reformulated fuels were calculated by applying the carbon content coefficient for the fuel additives listed in Table B-8 to the increased share of reformulated gasoline represented by these additives (standard gasoline contains small amounts of MTBE and TAME) and weighting the gasoline carbon content accordingly.

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

The carbon content for each grade and type of fuel is multiplied by the share of overall consumption that the grade and fuel type represent. Individual coefficients are then summed and totaled to yield an overall carbon content coefficient.

Data Sources

Data for the density of motor gasoline was obtained from the National Institute for Petroleum and Energy Research, *Motor Gasolines, Summer* and *Motor Gasolines, Winter* (1990 through 2002).

Data on the characteristics of reformulated gasoline was taken from the American Petroleum Institute, *Alcohols and Ethers: A Technical Assessment of Their Applications as Fuels and Fuel Components*, API 4261 (1988).

Data on the carbon content of motor gasoline was obtained from the following:

- Mark DeLuchi, *Emissions of Greenhouse Gases from the Use of Transportation Fuels and Electricity*, Volume 2, ANL/ESD/TM-22, Vol. 2 (November 1993), Appendix C, pp. C-1 to C-8.
- Ultimate analysis of one sample of shale-oil derived gasoline from Applied Systems Corp., *Compilation of Oil Shale Test Results* (April 1976), p. 3-2.
- Ultimate analysis of samples of three varieties of gasoline from C.C. Ward, "Petroleum and Other liquid Fuels," in *Marks' Standard Handbook for Mechanical Engineers* (1978), pp. 7-14.
- Ultimate analysis of one sample of gasoline from J.W. Rose and J.R. Cooper, *Technical Data on Fuel*, The British National Committee, World Energy Conference, London, England (1977).

Standard heat contents for motor gasoline of 5.253 MMBtu per barrel conventional gasoline and 5.150 MMBtu per barrel reformulated gasoline were adopted from EIA's *Annual Energy Review 2000*, Appendix A (2001). Available online at: <www.eia.doe.gov/emeu/aer/contents.html>.

Uncertainty

There are two primary contributors to the uncertainty of carbon content coefficients for motor gasoline. The first is the small number of motor gasoline samples and ultimate analyses from Deluchi, et al. However, as demonstrated above in Figure B-3, the amount of variation in carbon content of gasoline is restricted by the compounds in the fuel to ± 4 percent.

The second 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 carbon content per unit of volume, rather than per unit of energy. Adopting this approach, however, makes it difficult to compare U.S. carbon 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 which show a variation in density of ± 1.5 percent.

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 carbon content coefficient for jet fuel used in this report represents a consumption-weighted combination of the naphtha-based and kerosene-based coefficients.

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 carbon 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 and carbon share of kerosene-based jet fuels was based on the average composition of 39 fuel samples taken by Boeing Corporation (the leading U.S. commercial airline manufacturer) in 1989. The EIA’s standard heat content of 5.67 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

The carbon content for each jet fuel type is multiplied by the share of overall consumption of that fuel type. Individual coefficients are then summed and totaled to yield an overall carbon content coefficient

Data Sources

Data on the carbon content of naphtha-based jet fuel was taken from C.R. Martel and L.C. Angello, “Hydrogen Content as a Measure of the Combustion Performance of Hydrocarbon Fuels,” in *Current Research in Petroleum Fuels*, Volume I (1977), p. 116.

Data on the density of naphtha-based jet fuel was taken from the American Society for Testing and Materials, *ASTM and Other Specifications for Petroleum Products and Lubricants* (1985), p. 60.

Standard heat contents for kerosene- and naphtha- based jet fuels were adopted from EIA’s *Annual Energy Review 2000*, Appendix A (2001). Available online at <www.eia.doe.gov/emeu/aer/contents.html>.

Data on the carbon content and density of kerosene-based jet fuel was taken from O.J. Hadaller and A.M. Mommenty, *The Characteristics of Future Fuels*, Part 1, “Conventional Heat Fuels” (September 1990), pp. 46-50.

Uncertainty

Variability in jet fuel is relatively small with the average carbon 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 carbon 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 carbon 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.

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 the purposes of this report, the carbon content of No. 2 fuel oil is assumed to typify the carbon content of distillate fuel generally. The carbon share in No. 2 fuel oil was estimated based on the average of 11 ultimate analyses. This carbon share was combined with EIA's standard heat content of 5.825 MMBtu per barrel and the density of distillate assumed to be 35.5 degrees API, in accord with its heat content.

Data Sources

Data on the carbon contents and density was derived from four samples from C. T. Hare and R.L. Bradow, "Characterization of Heavy-Duty Diesel Gaseous and Particulate Emissions, and the Effects of Fuel Composition," in Society of Automotive Engineers, *The Measurement and Control of Diesel Particulate Emissions* (1979), p. 128.

Three samples from E.F. Funkenbush, D.G. Leddy, and J.H. Johnson, "The Organization of the Soluble Organic Fraction of Diesel Particulate Matter," in Society of Automotive Engineers, *The Measurement and Control of Diesel Particulate Emissions* (1979), p. 128.

One sample from R.L. Mason, "Developing Prediction Equations for Fuels and Lubricants," SAE Paper 811218, p.34 (1981).

One sample from C.T. Hare, K.J. Springer, and R.L. Bradow, "Fuel and Additive Effects on Diesel Particulate- Development and Demonstration of Methodology," in Society of Automotive Engineers, *The Measurement and Control of Diesel Particulate Emissions* (1979), p. 179.

One Sample from F. Black and L. High, "Methodology for Determining Particulate and Gaseous Diesel Emissions," in Society of Automotive Engineers, *The Measurement and Control of Diesel Particulate Emissions* (1979), p. 128.

A standard heat content was adopted from EIA's *Annual Energy Review 2000*, Appendix A (2001). Available online at <www.eia.doe.gov/emeu/aer/contents.html>.

Uncertainty

The primary source of uncertainty for the estimated carbon content of distillate fuel is the selection of No.2 fuel oil as the typical distillate fuel. No.2 fuel oil is generally consumed for home heating. No.1 fuel oil is generally less dense and if it is consumed in large portions for mobile sources, the carbon content estimated for this report is likely to be too high. The five No.1 fuel oil samples obtained by EIA contained an average of 86.01 percent carbon compared to the 86.34 percent contained in samples of No.2 fuel oil. A carbon content coefficient based on No.1 fuel oil would equal 19.72 Tg/QBtu rather than the 19.95 Tg/QBtu for No.2 fuel oil. There is also small uncertainty in the share of carbon based on the limited sample size of ± 1 percent.

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 a 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 and an average sulfur content of 1 percent (EIA 2001b). This implies a density of about 17 degrees API.

Methodology

For this report, residual fuel was defined as No.6 fuel oil. The National Institute of Petroleum and Energy Research, Fuel Oil Survey shows an average density for fuel oil of 11.3 API gravity and anecdotal evidence suggests that marine residual fuel is also very dense, with typical gravity of 10.5 to 11.5 degrees API (EIA 1993). Because the largest share of fuel oil consumption is for marine vessels, a density of 11 degrees API was adopted when developing the carbon content coefficient for this report. An average share of carbon in residual fuel of 85.67 percent by mass was used based on ultimate analyses of a dozen samples.

Data Sources

Data on carbon content was derived from three samples of residual fuel from the Middle East and one sample from Texas. These data were found in F. Mosby, G.B. Hoekstra, T.A. Kleinhenz, and J.M. Sokra, "Pilot Plant Proves Resid Process," in *Chemistry of Petroleum Processing and Extraction* (1976), p.227.

Three samples of heavy fuel oils from J.P. Longwell, "Interface Between Fuels and Combustion," in *Fossil Fuel Combustion: A Sourcebook* (1991).

Three samples of heavy fuel oils from C.C. Ward, "Petroleum and Other Liquid Fuels," in *Marks' Standard Handbook for Mechanical Engineers* (1978), pp. 7-14.

Two samples of heavy fuel oils from, D.A. Vorum, "Fuel and Synthesis Gases from Gaseous and Liquid Hydrocarbons," in American Gas Association, *Gas Engineer's Handbook* (1974), p. 3/71.

One sample of heavy fuel oil from W. Rose and J.R. Cooper, *Technical Data on Fuel*, The British National Committee, World Energy Conference, London, England (1977).

Density of residual fuel consumed for electric power generation was obtained from EIA's *Cost and Quality of Fuels*, (2001b). Available online at <www.eia.doe.gov/cneaf/electricity/cq/cq_sum.html>.

Density of residual fuel consumed in marine vessels from EIA's Petroleum Supply Division, *Btu Tax on Finished Petroleum Products* (1993) and National Institute for Petroleum and Energy Research's *Fuel Oil Surveys* (1992).

A standard heat content was adopted from EIA's *Annual Energy Review 2000*, Appendix A (2001). Available online at <www.eia.doe.gov/emeu/aer/contents.html>.

Uncertainty

The largest source of uncertainty for estimating the carbon content of residual fuel centers on the estimates of density, which differ from power generation to marine vessel fuels. The difference between the density implied by the energy content of utility fuels and the density observed in the NIPER surveys is probably due to nonsulfur impurities, which reduce the energy content without greatly affecting the density of the product. Impurities of several percent are commonly observed in residual oil. The presence of these impurities also affects the share of the fuel that is carbon. Overall, the uncertainty associated with the carbon content of residual fuel is probably ± 1 percent.

Liquefied Petroleum Gases (LPG)

EIA identifies four categories of paraffinic hydrocarbons as LPG: ethane, propane, isobutane, and n-butane. Because each of these compounds is a pure paraffinic hydrocarbon, their carbon shares are easily derived by taking into account the atomic weight of carbon (12) and the atomic weight of hydrogen (1). Thus, for example, the carbon share of propane, C₃H₈, is 81.8 percent. The densities and heat content of the compounds are also well known allowing carbon content coefficients to be calculated directly. Table B-9 summarizes the physical characteristic of LPG.

Table B-9. Physical Characteristics of Liquefied Petroleum Gases

Compound	Chemical Formula	Density (Barrels Per Metric Ton)	Carbon Content (Percent)	Energy Content (MMBtu/Barrel)	Carbon Content Coefficient (Tg/QBtu)
Ethane	C ₂ H ₆	16.88	80.0	2.916	16.25
Propane	C ₃ H ₈	12.44	81.8	3.824	17.20
Isobutane	C ₄ H ₁₀	11.20	82.8	4.162	17.75
n-butane	C ₄ H ₁₀	10.79	82.8	4.328	17.72

Source: Guthrie (1960).

Methodology

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

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

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

A carbon content coefficient for LPG used as fuel is developed based on the consumption mix of the individual compound reported in U.S. energy statistics.

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

The mix of LPG consumed for non-fuel use differs significantly from the mix of LPG that is combusted. While the majority of LPG consumed for fuel use is propane, ethane is the largest component of LPG used for non-fuel applications. A carbon content coefficient for LPG used for non-fuel applications is developed based on the consumption mix of the individual compound 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 LPG fuel use and non-fuel use consumption appear below in Table B-10.

Table B-10. Consumption and Carbon Content Coefficients of Liquefied Petroleum Gases, 1990-2001 (Tg/QBtu)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Consumption (Quads Fuel Use)												
Ethane	0.03	0.02	0.03	0.02	0.02	0.02	0.03	0.05	0.05	0.06	0.06	0.05
Propane	0.79	0.79	0.84	0.86	0.86	0.86	0.95	0.92	0.98	0.98	0.98	0.89
Butane	0.08	0.05	0.07	0.06	0.07	0.05	0.04	0.05	0.05	0.06	0.06	0.06
Total	0.90	0.85	0.94	0.94	0.96	0.93	1.02	1.03	0.99	1.10	1.10	1.01
Carbon Content	17.21	7.21	17.21	17.22	17.22	17.20	17.20	17.18	17.18	17.18	17.18	17.18
Consumption (Quads non-Fuel Use)												
Ethane	0.55	0.62	0.62	0.65	0.65	0.68	0.74	0.71	0.68	0.77	0.81	0.73
Propane	0.53	0.59	0.61	0.55	0.65	0.67	0.65	0.71	0.68	0.76	0.76	0.69
Butane	0.13	0.17	0.16	0.15	0.25	0.24	0.26	0.25	0.24	0.28	0.29	0.27
Total	1.20	1.38	1.39	1.35	1.55	1.59	1.65	1.67	1.60	1.81	1.86	1.69
Carbon Content	16.83	16.84	16.84	16.80	16.88	16.87	16.86	16.88	16.87	16.88	16.87	16.88
Weighted Carbon Content	16.99	16.98	16.99	16.97	17.01	17.00	16.99	16.99	16.99	16.99	16.99	16.99

Sources: Consumption of LPG from EIA (1995 through 2001). Non-fuel use of LPG from API (1990 through 2001).

Data Sources

Data on carbon share, density, and heat content of LPG was obtained from V.B. Guthrie (ed.), *Characteristics of Compounds*, Petroleum Products Handbook, (1960), p.3-3.

Data on LPG consumption was obtained from U.S. Department of Energy, Energy Information Administration, *Petroleum Supply Annual* (1990 through 2002). Available online at www.eia.doe.gov/oil_gas/petroleum/data_publications/petroleum_supply_annual/psa_volume1/psa_volume1.html.

Non-fuel use of LPG from American Petroleum Institute, Natural Gas Liquids and Liquefied Refinery Gas Survey (1990 through 2002).

Uncertainty

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

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 D 910 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 carbon 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. To estimate the share of carbon 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 carbon share of 85 percent and a carbon content coefficient of 18.87 Tg/QBtu.

Data Sources

Data sources include American Society for Testing and Materials, *ASTM and Other Specifications for Petroleum Products and Lubricants* (1985).

A standard heat content for aviation gas was adopted from EIA's *Annual Energy Review 2000*, Appendix A (July 2001). Available online at <www.eia.doe.gov/emeu/aer/contents.html>.

Uncertainty

The uncertainty associated with the carbon 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 carbon 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. 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 byproducts, it is difficult to determine what represents typical still gas.

Methodology

The EIA obtained data on four samples of still gas. Table B-11 below shows the composition of those samples.

Table B-11. Composition, Energy Content, and Carbon Content Coefficient for Four Samples of Still Gas

Sample	Hydrogen (%)	Methane (%)	Ethane (%)	Propane (%)	Btu Per Cubic Foot	Carbon Content (Tg/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

Because gas streams with a large free hydrogen content are likely to be used as refinery or chemical feedstocks, EIA selected the carbon content coefficient from the sample with the lowest hydrogen content as the representative value for still gas.

Data Sources

One still gas sample from American Gas Association, *Gas Engineer's Handbook* (1974), pp. 3/71, 3.87.

Three still gas samples from C.R. Guerra, K. Kelton, and D.C. Nielsen, Natural Gas Supplementation with Refinery Gases and Hydrogen," in Institute of Gas Technology, *New Fuels and Advances in Combustion Technologies* (1979).

Uncertainty

Because the composition of still gas is highly heterogeneous, the carbon content coefficient for this product is highly uncertain, with an accuracy of ± 33 percent. The carbon content coefficient used for this report is probably at the high end of the plausible range.

Asphalt

Asphalt is used to pave roads. Because most of its carbon is retained in those roads, it is a small source of emissions. It is derived from a class of hydrocarbons called "asphaltenes," 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 carbon contents than other hydrocarbons.

Methodology

Ultimate analyses of twelve samples of asphalts showed an average carbon content of 83.5 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 carbon content coefficient of 20.62 Tg/QBtu.

Data Sources

A standard heat content for asphalt was adopted from EIA's *Annual Energy Review 2000*, Appendix A (2001). Available online at <www.eia.doe.gov/emeu/aer/contents.html>.

The density of asphalt was determined by the American Society for Testing and Materials, in *ASTM and Other Specifications for Petroleum Products and Lubricants* (1985).

Uncertainty

The share of carbon 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 carbon share and total heat content in asphalts do vary systematically, the overall carbon 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. Ultimate analysis of a single sample of motor oil yielded a carbon content of 85.8 percent. A standard heat content of 6.065 MMBtu per barrel was adopted from EIA. These factors produce a carbon content coefficient of 20.24 Tg/QBtu.

Data Sources

A standard heat content was adopted from the EIA's *Annual Energy Review 2000*, Appendix A (2001). Available online at <www.eia.doe.gov/emeu/aer/contents.html>.

The density of asphalt was determined by the American Society for Testing and Materials in *ASTM and Other Specifications for Petroleum Products and Lubricants* (1985).

Uncertainty

Uncertainty in the estimated carbon 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 carbon content coefficients range from just under 20.0 Tg/QBtu to about 21.5 Tg/QBtu or an uncertainty band from -1 percent to + 6 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 400 degrees Fahrenheit and above.

Methodology

The method for estimating the carbon content of petrochemical feedstocks includes three 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 carbon share of 84.11 percent and an average density of 67.1 degrees API gravity. The standard EIA heat content of 5.248 MMBtu per barrel is used to estimate a carbon content coefficient of 18.14 Tg/QBtu.

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

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. Thus, the carbon content coefficient of 19.95 Tg/Btu used for distillate fuel is also adopted for this portion of petrochemical feedstocks.

Step 3. Weight the carbon content coefficients for the two classes of petrochemical feedstock by consumption

The weighted average of the two carbon content coefficients for petroleum feedstocks equals 19.37 Tg/Btu.

Data Sources

Data on the carbon content and density of naphtha was taken from G.H. Unzelman, "A Sticky Point for Refiners: FCC Gasoline and the Complex Model," *Fuel Reformulation* (July/August 1992), p. 29.

A standard heat content for petrochemical feedstock was adopted from EIA's *Annual Energy Review 2000*, Appendix A (2001). Available online at <www.eia.doe.gov/emeu/aer/contents.html>.

Uncertainty

Petrochemical feedstocks are not so much distinguished on the basis of chemical composition as on the identity of the purchaser, who may be presumed to be a chemical company or a petrochemical unit co-located on the refinery grounds. This produces a considerable degree of uncertainty about the exact composition of petrochemical feedstocks. Since the carbon content coefficient for petrochemical feedstocks is a weighted average of the coefficients for naphtha and some class of middle distillates, the accurate coefficient is likely bounded by the two individual coefficients, suggesting an uncertainty of ± 6 percent.

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 fuel oil.

Methodology

The average density of 41.4 degrees API and average carbon share of 86.01 percent found in five ultimate analyses of No. 1 fuel oil samples were applied to a standard heat content of 5.67 MMBtu per barrel to yield a carbon content coefficient of 19.72 Tg/Btu.

Data Sources

A standard heat content was adopted from EIA's *Annual Energy Review 2000*, Appendix A (2001). Available online at <www.eia.doe.gov/emeu/aer/contents.html>.

Uncertainty

Uncertainty in the estimated carbon content for kerosene is driven by the selection of No. 1 fuel oil as a proxy for kerosene. If kerosene is more like kerosene-based jet fuel, the true carbon content coefficient is likely to be some 2 percent lower. If kerosene is more aptly compared to No. 2 fuel oil, then the true carbon content coefficient is likely to be about 1 percent higher.

Petroleum Coke

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

Methodology

Ultimate analyses of two samples of petroleum coke showed an average carbon share of 92.3 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 carbon content coefficient of 27.85 Tg/QBtu.

Data Sources

Carbon content was derived from two samples from S. W. Martin, "Petroleum Coke," in Virgil Guthrie (ed.), *Petroleum Processing Handbook* (1960), pp. 14-15.

The density of petroleum coke was taken from the American Society for Testing and Materials, *ASTM and Other Specifications for Petroleum Products and Lubricants* (1985).

A standard heat content for petroleum coke was adopted from EIA's *Annual Energy Review 2000*, Appendix A (2001). Available online at <www.eia.doe.gov/emeu/aer/contents.html>.

Uncertainty

The uncertainty associated with the estimated carbon content coefficient of petroleum coke can be traced to two factors: the use of only two samples to establish carbon contents and a standard heat content which may be too low. Together, these uncertainties are likely to bias the carbon 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: stoddard solvent, used in dry cleaning; high flash point solvent, used as an industrial paint because of its slow evaporative characteristics; odorless solvent, most often used for residential paints; and high solvency mineral spirits, used for architectural finishes. These products differ in both density and carbon percentage, requiring the development of multiple coefficients.

Methodology

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

Step 1. Estimate the carbon content coefficient for hexane

Hexane is a pure paraffin containing 6 carbon atoms and 14 hydrogen atoms. Thus, it is 83.7 percent carbon. Its density is 76.6 degrees API or 5.649 pounds per gallon and its derived carbon content coefficient is 17.17 Tg/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 carbon content factors contained in Table B-12 below.

Table B-12. Characteristics of Non-hexane Special Naphthas

Special Naphtha	Aromatic Content (Percent)	Density (Degrees API)	Carbon Content (Percent)	Carbon Content (Tg/Btu)
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

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 carbon 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 19.86 Tg/QBtu.

Data Sources

A standard heat content for special naphtha was adopted from EIA's *Annual Energy Review 2000*, Appendix A (2001). Available online at <www.eia.doe.gov/emeu/aer/contents.html>.

Density and aromatic contents were adopted from K. Boldt and B.R. Hall, *Significance of Tests for Petroleum Products*, American Society for Testing and Materials (1977), p. 30.

Uncertainty

The principal uncertainty associated with the estimated carbon 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 carbon content of hexane and on the upper end by the carbon content of high solvency mineral spirits. This implies an uncertainty band of -15 percent to + 6 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 carbon atoms and the type of hydrocarbon compounds. Microcrystalline waxes have longer carbon chains and more variation in their chemical bonds than paraffin waxes.

Methodology

The method for estimating the carbon 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 carbon atoms. The resulting carbon 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 carbon atoms, yielding a carbon 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*.

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 carbon content was calculated for petroleum waxes, assuming that wax consumption is 80 percent paraffin wax and 20 percent microcrystalline wax. The weighted average carbon content is 85.29 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 carbon content coefficient for petroleum waxes of 19.81 Tg/QBtu.

Data Sources

Density of paraffin wax was taken from American Society for Testing and Materials, *ASTM and Other Specifications for Petroleum Products and Lubricants* (1985).

Density of microcrystalline waxes was derived from 10 samples found in V. Guthrie (ed.), *Petroleum Products Handbook* (1960).

A standard heat content for petroleum waxes was adopted from EIA's *Annual Energy Review 2000*, Appendix A (2001). Available online at <www.eia.doe.gov/emeu/aer/contents.html>.

Uncertainty

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

Crude Oil, Unfinished Oils, and Miscellaneous

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 carbon accounting purposes, it was assumed that all these products have the same carbon content as crude oil.

Methodology

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

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

Absent the term representing sulfur content, the equation had an R-squared of only 0.35.⁷ When carbon content was adjusted to exclude sulfur, the R-squared rose to 0.65. While sulfur is the most important nonhydrocarbon 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 carbon 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 2001 crude oil quality data (30.49 degrees API and 1.42 percent sulfur) produces an estimated carbon content of 85.81 percent. Applying the density and carbon content to the EIA standard energy content for crude oil of 5.8 MMBtu per barrel produced an emissions coefficient of 20.29 Tg/QBtu.

⁷ R-squared represents the percentage of variation in the dependent variable (in this case carbon content) explained by variation in the independent variables.

Data Sources

Carbon content was derived from 150 crude oil samples from U.S. National Research Council, *International Critical Tables of Numerical Data, Physics, Chemistry, and Technology* (1927).

A standard heat content for crude oil was adopted from the EIA's *Annual Energy Review 2000*, Appendix A (2001). Available online at <www.eia.doe.gov/emeu/aer/contents.html>.

Uncertainty

The uncertainty of the estimated carbon 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 carbon content coefficient by ± 3 percent. Since unfinished oils and miscellaneous products are impossible to define, the uncertainty of applying a crude oil carbon 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

Coal

The estimates of carbon content coefficients for coal were updated and revised in 2002. The methodology employed for these estimates was unchanged from previous years; however, the underlying coal data sample set was updated. Previously a set of 5,426 coal samples from the EIA Coal Analysis File was used to develop carbon content estimates. The results from that sample set appear below in Table B-13. 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 updated sample set included 6,588 coal samples collected by the U.S. Geological Survey between 1973 and 1989.

Table B-13. Carbon Content Coefficients for Coal by Consuming Sector and Coal Rank, 1990-2000 (Tg/QBtu)

Consuming Sector	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
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
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 Hong and Slatnick (1994) and emission factors by rank from SAIC (1992).

Petroleum Products

Jet Fuel

Between 1994 and 1995, the carbon content coefficient for kerosene-based jet fuel was revised downward from 19.71 Tg/QBtu to 19.33 Tg/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 Momenty in 1990. The downward revision was a result of a decrease in density, as well as slightly lower carbon 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 carbon content coefficient.

Liquefied Petroleum Gases (LPG)

The carbon content coefficient of LPG is updated annually to reflect changes in the consumption mix of the underlying 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 carbon per unit of energy, its removal from the consumption mix lowered the carbon content coefficient for LPG from 17.26 Tg/QBtu to 17.02 Tg/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 carbon content coefficient for fuel use is about 2 percent higher than the coefficient for non-fuel use.

Motor Gasoline

The carbon 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 carbon content coefficients for motor gasoline. This change resulted in a downward step function in carbon content coefficients for gasoline of approximately 0.3 percent beginning in 1995.

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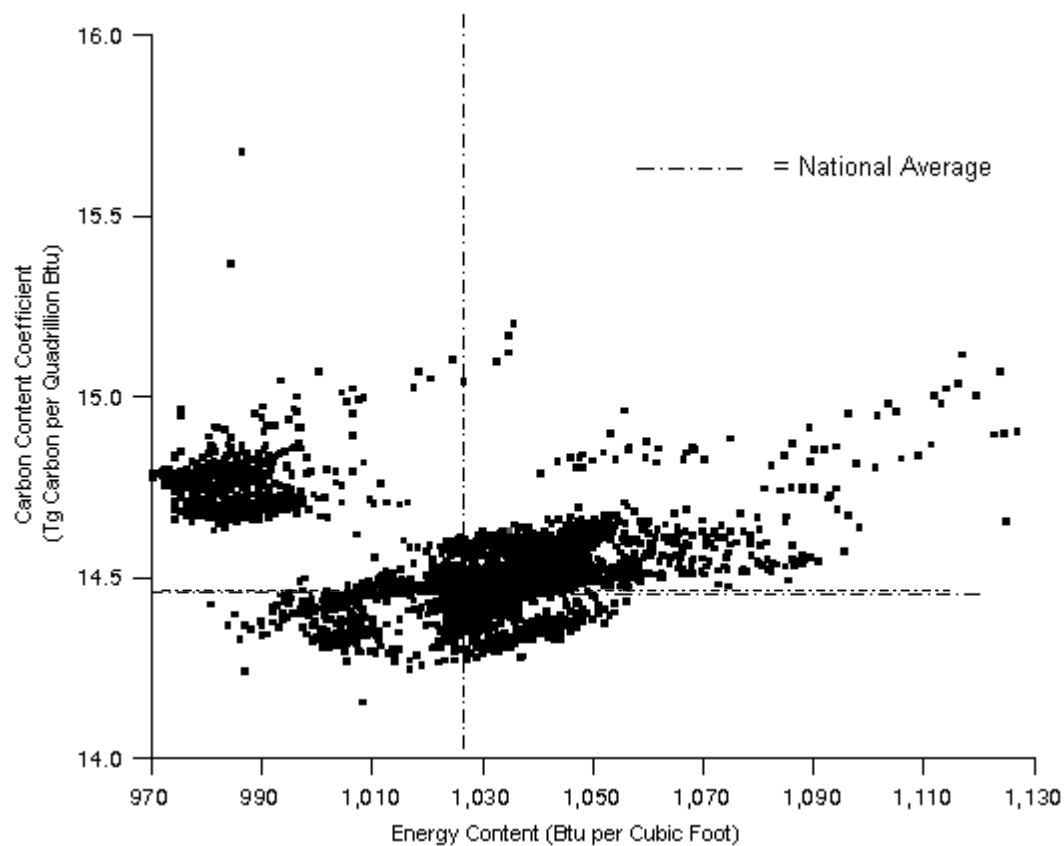
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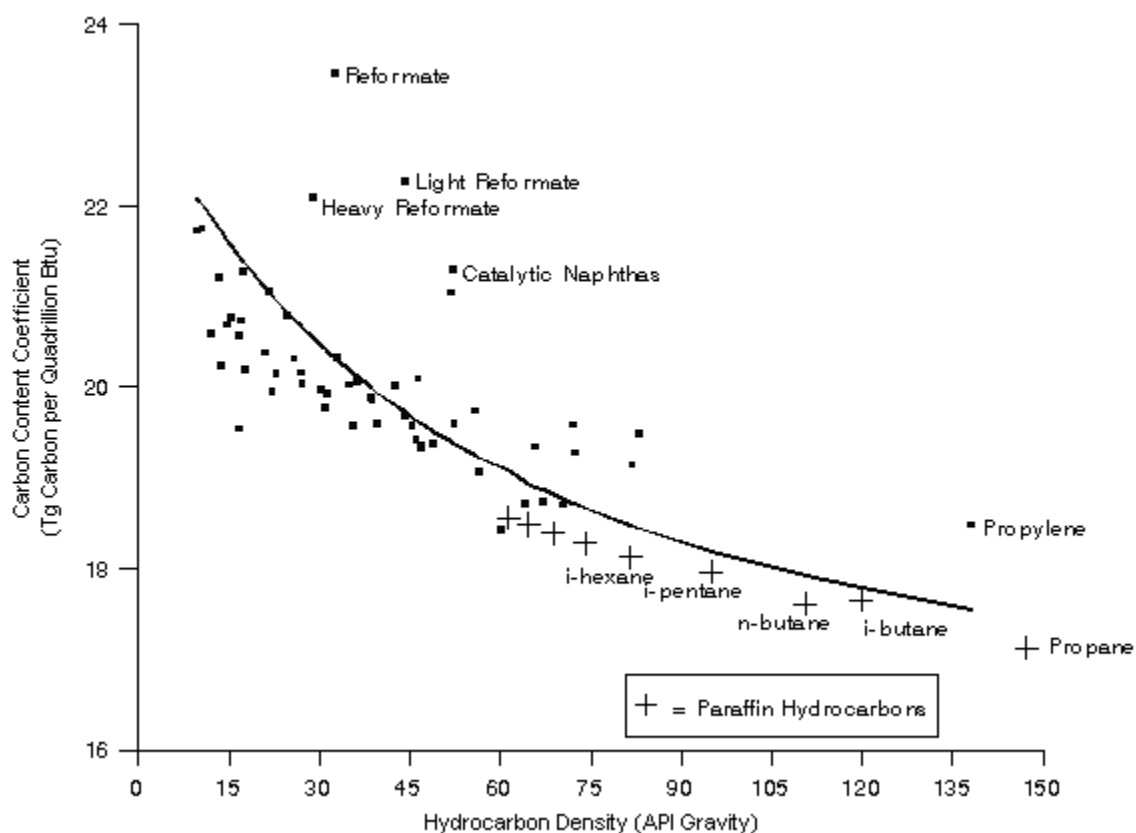
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Figure B-1: Carbon Content for Samples of Pipeline-Quality Natural Gas Included in the Gas Technology Institute (Formerly Gas Research Institute) Database



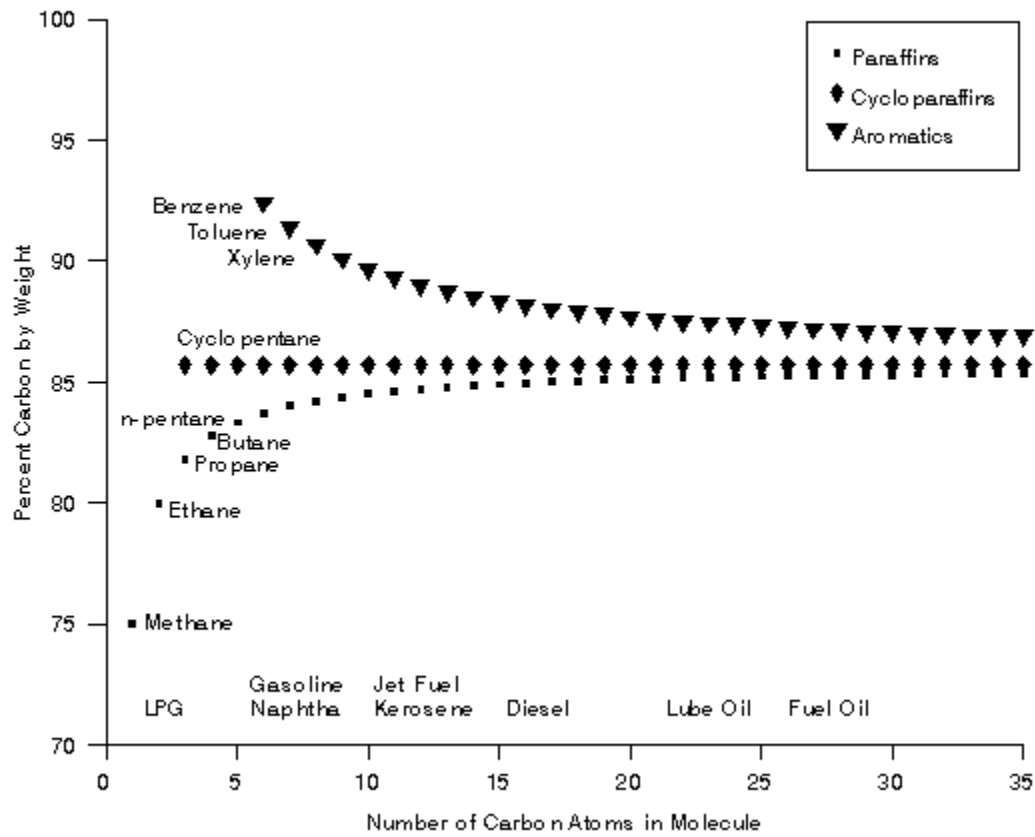
Source: EIA (1994) Energy Information Administration, Emissions of Greenhouse Gases in the United States 1987-1992, U.S. Department of Energy, Washington, DC, November, 1994, DOE/EIA 0573, Appendix A.

Figure B-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.

Figure B-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.

ANNEX C

Methodology for Estimating Carbon Stored in Products from Non-Energy Uses of Fossil Fuels

Carbon 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 carbon content) by a fuel-specific storage factor. This Annex explains the methods and data sources employed in developing the storage factors for asphalt and road oil, lubricants, petrochemical feedstocks, liquefied petroleum gases (LPG), pentanes plus, and natural gas used for chemical manufacturing plant feedstocks (i.e., not used as fuel.) The storage factors for the remaining non-energy fuel uses are based on values reported by Marland and Rotty (1984) and recommended for use by IPCC (1997).

Table C-1: Fuel Types and Percent of Carbon Stored for Non-Energy Uses

Fuel Type	Storage Factor (%)
Industrial Coking Coal ^a	75%
Natural Gas to Chemical Plants	-
Nitrogenous Fertilizers	0%
Other Uses	61%
Asphalt & Road Oil	100%
Liquefied Petroleum Gas (LPG)	61%
Lubricants	9%
Pentanes Plus	61%
Petrochemical Feedstocks	-
Naphtha (b.p.<401° F)	61%
Other Oil (b.p.>401° F)	61%
Petroleum Coke ^b	50%
Special Naphtha	0%
Other	-
Distillate Fuel Oil	50%
Residual Fuel	50%
Waxes	100%
Miscellaneous Products	100%

- Not applicable

^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 chapter.

^b Includes processes for which specific petroleum coke consumption and emission factor data are not available (e.g., carbon fibers and textiles, refractory, electric motor parts, brake parts, batteries). Consumption of petroleum coke for production of primary aluminum anodes, electric arc furnace anodes, titanium dioxide, and ferroalloys is covered in the Industrial Processes chapter.

The following sections describe the selected 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—petrochemical feedstocks, pentanes plus, LPG, and natural gas—are used in organic chemical synthesis and in other manufacturing processes. 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, road oil and lubricants follow.

Petrochemical Feedstocks, Pentanes Plus, Liquefied Petroleum Gases, and Natural Gas

Petrochemical feedstocks, pentanes plus, liquefied petroleum gases (LPG) and natural gas¹ 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 four fuel types. Chemically speaking, these fuels are diverse, ranging from simple natural gas (i.e., predominantly methane, CH₄) to heavier, more complex naphthas and other oils.² The storage factor for petrochemical feedstocks, pentanes plus, LPG, and natural gas used for purposes other than fuel is estimated based on data for the year 1998, which is the latest year for which data are available from several key data sources concerning consumption for non-fuel uses.

The four fuel categories constituted approximately 238.2 Tg CO₂ Eq., or 57 percent, of the 416.6 Tg CO₂ Eq. of non-energy fuel consumption in 1998. Of this amount for the four fuels, 14.3 Tg CO₂ Eq. was exported, resulting in a net U.S. consumption of 223.9 Tg CO₂ Eq. in 1998. Of this net consumption, 136.3 Tg CO₂ Eq. was destined for long-term storage in products—including products subsequently combusted for waste disposal—while the remaining 87.7 Tg CO₂ Eq. was emitted to the atmosphere directly as CO₂ (e.g., through combustion of industrial byproducts) or indirectly as CO₂ 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 CO₂ in the atmosphere. For 1998 the storage factor for the four fuel categories was 60.9 percent; this factor was assumed to be constant over the 1990 through 2001 period. The derivation of the storage factor is described in the following sections.

Methodology and Data Sources

An empirically determined storage factor was developed for the carbon consumed for non-energy end uses of petrochemical feedstocks, pentanes plus, LPG, and natural gas (henceforth referred to as feedstocks). The storage factor is equal to the ratio of carbon stored in the final products to total carbon 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 four 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* (EIA 2001c) publication tracks imports and exports of petrochemical feedstocks, including butanes, butylenes, ethane, ethylene, propane, propylene, LPG, 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, and polypropylene resins), which were derived from the primary chemicals produced by the refineries. These products represent very large flows of carbon derived from fossil fuels (i.e., fossil carbon), so estimates of net flows not already considered in EIA's dataset were developed for the entire time series from 1990 to 2001.

The approach to estimate imports and exports involves three steps:

- Step 1.* Identify commodities derived from petrochemical feedstocks, and calculate net import/export for each.
- Step 2.* Estimate the carbon content for each commodity.
- Step 3.* Sum the net carbon imports/exports across all commodities.

Step 1 relies heavily on information provided by the National Petrochemical and Refiners Association (NPRA) and trade statistics published by the U.S. Bureau of the Census (BoC). NPRA provided a spreadsheet of

¹ Natural gas has two categories of non-energy consumption: for fertilizer and for other chemical syntheses. Only natural gas that is supplied to chemical plants for other uses is included here. Natural gas used for fertilizer is not included because it covered in the Industrial Processes chapter.

² Naphthas are compounds distilled from petroleum containing 4 to 12 carbon atoms per molecule and having a boiling point less than 401° F. Other oils are distillates containing 12 to 25 carbon atoms per molecule and having a boiling point greater than 401° F.

the ten-digit BoC Harmonized Tariff Schedule (HTS) Commodity Codes used to compile import-export data for periodic reports issued to NPRA's membership on trade issues. 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* included in the totals, however, as these commodities are petrochemicals produced from fossil fuels for export, and deplete domestic petrochemical feedstocks. Imports and exports of commodities for which production and consumption data are provided by EIA (e.g., butane, ethylene, liquefied petroleum gases) are also not included in the totals, to avoid double counting.

The BoC trade statistics are publicly available³ and cover a complete time series from 1990 to 2001. 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 carbon 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 carbon imports/exports across all commodities. The results of this step are shown in Table C-2. As shown in the table, the United States has been a net exporter of chemical intermediates and products throughout the 1990 to 2001 period.

Table C-2: Net Exports of Petrochemical Feedstocks, 1990 – 2001 (Tg CO₂ Eq.)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Net Exports	8.6	10.3	8.5	9.9	10.1	12.1	12.2	16.7	14.3	13.8	13.0	6.4

For each year in the inventory, the total carbon 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 C-2) to yield net domestic fuel consumption for non-energy. The balance was apportioned to either stored carbon or emissive carbon, based on a storage factor.

The overall storage factor for the feedstocks was determined by developing a mass balance on the carbon in feedstocks, and characterizing products, uses, and environmental releases as resulting in either storage or emissions. The total carbon in the system was estimated by multiplying net domestic consumption for non-energy by the carbon content of each of the feedstocks (i.e., petrochemical feedstocks-naphtha, petrochemical feedstocks-other oils, LPG, pentanes plus, natural gas). Carbon content values for the fuel feedstocks are discussed in Annexes A and B.

Next, carbon pools and releases in a variety of products and processes were characterized. The major product categories are plastics, synthetic rubber, synthetic fibers, carbon black, industrial non-methane volatile organic compound (NMVOC) emissions, industrial toxic chemical (i.e., TRI) releases, pesticides, and organic solvents.⁴

The carbon in each product or waste produced was categorized as either stored or emitted. The aggregate storage factor is the carbon-weighted average of storage across fuel types. As discussed later in the section on uncertainty, data were not available for all of the non-energy end uses of fuel feedstocks, so the uses analyzed represent a sample of the total carbon consumed. The sample accounts for 200.5 Tg CO₂ Eq., or 90 percent, of the 223.9 Tg CO₂ Eq. of carbon within these fuel feedstock types that is consumed domestically for non-energy purposes. The remaining 10 percent (23.4 Tg CO₂ Eq.) that is "unaccounted for" is assumed to be emitted, not stored. The total amount of carbon that is stored in products, including the amount subsequently emitted as CO₂ as a

³ See the U.S International Trade Commission (USITC) Trade Dataweb at <<http://dataweb.usitc.gov/>>.

⁴ 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.

result of waste combustion, corresponds to 136.3 Tg CO₂ Eq. Emissions of CO₂ from waste combustion are accounted for separately in the Inventory and are discussed in the Waste Combustion section of the Energy chapter.

The following sections provide details on the calculation steps, assumptions, and data sources employed in estimating and classifying the carbon in each product and waste shown in Table C-2. Summing the carbon stored and dividing it by the total fuel feedstock carbon used yields the overall storage factor, as shown in the following equation:

$$\text{Overall Storage Factor} = \text{Carbon Stored} / \text{Total Carbon} = 136.3 \text{ Tg CO}_2 \text{ Eq.} / 223.9 \text{ Tg CO}_2 \text{ Eq.} = 60.9 \%$$

Table C-3: Carbon Stored and Emitted by Products from Petrochemical Feedstocks, Pentanes Plus, LPG, and Natural Gas in 1998 (Tg CO₂ Eq.)

Product/Waste Type	Carbon Stored	Carbon Emitted
Industrial Releases	0.1	8.2
TRI Releases	0.1	1.0
Industrial VOCs		4.0
Non-combustion CO	-	1.3
Refinery wastewater		0.1
Hazardous Waste Incin.	-	1.9
Energy Recovery	-	41.1
Products	136.2	15.0
Plastics	110.4	-
Synthetic Rubber	7.7	-
Synthetic Fiber	11.7	-
Carbon Black	5.9	-
Pesticides	0.4	0.2
Soaps, shampoos, detergents		4.9
Solvent VOCs	-	9.9
Unaccounted for*		23.4
Total	136.3	87.7

- Not applicable

* Unaccounted for carbon was assumed to be emitted.

Note: Totals may not sum due to independent rounding.

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

Industrial Releases

Industrial releases include toxics reported through the Toxics Release Inventory, industrial emissions of volatile organic compounds (VOCs), carbon monoxide emissions (other than those related to fuel combustion), treatment of refinery wastewater, and hazardous waste incineration.

TRI Releases

Carbon is also found in toxic substances released by industrial facilities. The Toxic Release Inventory (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 carbon 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 carbon stored and emitted in the form of toxic releases can be estimated.

The TRI specifies releases by chemical, so carbon 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.”⁵ The carbon released in each disposal location is provided in Table C-4.

Each on-site classification was assigned a storage factor. A one hundred percent storage factor was applied to disposition of carbon 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 CO₂ (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 carbon-weighted average storage factor for the on-site carbon 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 carbon content value, based upon the top 35 chemicals’ carbon 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.

Table C-4: 1998 TRI Releases by Disposal Location (Gg CO₂ Eq.)

Disposal Location	Carbon Stored	Carbon Emitted
Air Emissions	-	924.0
Surface Water Discharges	-	6.7
Underground Injection	89.4	-
RCRA Subtitle C Landfill Disposal	1.4	-
Other On-Site Land Releases	-	15.9
Off-site Releases	6.4	36.0
Total	97.2	982.6

- Not applicable

Note: Totals may not sum due to independent rounding.

Volatile Organic Compound Emissions from Industrial Processes and Solvent Evaporation

Data on annual non-methane volatile organic compound (NMVOC) emissions were obtained from the National Air Quality and Emissions Trends Report (EPA 2000b). The report includes information on NMVOC emissions end-use category; some of these fall into the heading of “industrial releases” in Table C-3 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 chemical and allied products, petroleum and 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 of the four fuel types 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 carbon content of the NMVOCs for each category of emissions. The assumptions for calculating the carbon fraction of industrial and solvent utilization emissions were made separately and differ significantly. For industrial NMVOC emissions, the carbon content of 85 percent was assumed. This value was chosen to reflect the carbon 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 (carbon contents ranging from 80 to 85 percent based upon carbon number), alkenes (carbon contents equal 85.7 percent), and some aromatics (carbon contents approximately 90 percent, depending upon substitution).

An EPA solvent evaporation emissions dataset (EPA 2000b) was used directly to estimate the carbon 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 carbon of each compound identified in the EPA solvent evaporation emissions dataset was calculated based on the molecular formula of the individual compound (e.g., the

⁵ Only the top 9 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 9 chemicals (i.e., 8 percent attributed to RCRA Landfills and 92 percent in the “Other” category).

carbon content of methylene chloride is 14 percent; the carbon 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 carbon content of the category was estimated based on the carbon content of the representative compound. The overall carbon content of the solvent evaporation emissions is estimated to be 56 percent.

The results of the industrial and solvent NMVOC emissions analysis are provided in Table C-5.

Table C-5: 1998 Industrial and Solvent NMVOC Emissions

Activity	Thousand short tons	Carbon Content	Carbon Emitted (Tg CO ₂ Eq.)
Industrial NMVOCs ^a	1,417	85%	4.0
Solvent Evaporation ^b	4,950	56%	9.9

^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 obtained from the National Air Quality and Emissions Trends Report (EPA 2000a). There are four categories of CO emissions in EPA (2000a) that are classified as process-related emissions not related to fuel combustion. These include chemical and allied products manufacturing, metals processing, petroleum and related industries, and other industrial processes. Some of these CO emissions are accounted for in the Industrial Processes section of this report, and are therefore not accounted for in this section, including total carbon emissions from the primary aluminum, titanium dioxide, iron and steel, and ferroalloys production processes. The total carbon (CO and CO₂) emissions from oil and gas production and asphalt manufacturing are also accounted for elsewhere in this Inventory. Sustainably harvested biogenic emissions (e.g., pulp and paper process emissions) are also excluded from calculation of CO emissions in this section. Those CO emissions that are not accounted for elsewhere are considered to be byproducts of non-fuel use of feedstocks and are included in the calculation of the petrochemical feedstocks storage factor. Table C-6 lists the industrial processes and CO emissions that remain after taking into account the exclusions above.

Table C-6: Carbon Monoxide Non-Combustion Emissions (Gg)

Source	1998
Chemical and Allied Products	
Organic Chemical Manufacture	83.6
Inorganic Chemical Manufacture, Other	2.7
Polymer and Resin Manufacture	4.5
Agricultural Chemical Manufacture	11.8
Paint, Varnish, Lacquer Manufacture	-
Pharmaceutical Manufacture	-
Other Chemical Manufacture	23.6
Metals Processing	
Nonferrous Metals Processing, Other	145.5
Metals Processing NEC	40.0
Petroleum and Related Industries	
Petroleum Refineries and Related Industry	300.9
Other Industrial Processes	
Rubber and Misc. Plastic Products	-
Mineral Products	169.1
Machinery Products	0.91
Electronic Equipment	-
Transportation Equipment	-
Misc. Industrial Processes	18.2
Total	801.7
Total (Tg CO₂ Eq.)	1.3

Note: Totals may not sum due to independent rounding.

Refinery Wastewater

Carbon flows associated with the treatment and discharge of refinery wastewater are included in the mass balance. To develop an estimate of annual emissions associated with the wastewater, it was assumed that the average concentration of Total Organic Carbon in refinery effluents was 10.5 mg/L, based on 1992 data reported in EPA's Permit Compliance System. It was also assumed that (a) the overall treatment efficiency (excluding recycling of oil back to the refinery) was 90 percent, (b) average flow is about 1 million gallons per day (3,800 m³/day), there are 192 operating refineries in the United States, (c) the majority of organic compounds in refinery wastewater are not covered by the TRI requirements (and thus there is no significant double-counting of releases with the TRI estimate), and (d) all of the carbon in the raw wastewater is destined for emission as CO₂. Based on these assumptions, annual emissions are roughly 0.1 Tg CO₂ Eq. Note that fugitive air emissions of methane from treatment of refinery wastewater are already accounted for in the inventory in the category of "Petroleum Systems," but other fugitive air emissions and discharges of wastewater to surface water or publicly owned treatment works are not included elsewhere in the inventory.

Hazardous Waste Incineration

Hazardous wastes are defined by the EPA under the Resource Conservation and Recovery Act (RCRA).⁶ 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 the 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 U.S. is burned in BIFs; these processes are included in the energy recovery calculations described above.

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 Biennial Reporting System (BRS) database (EPA 2000a). 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 carbon 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 appropriate carbon content factors from Marland and Rotty (1984) yields tons of carbon emitted. Implied carbon content is calculated by dividing the tons of carbon emitted by the associated tons of waste incinerated.

Waste quantity data for hazardous wastes were obtained from EPA's BRS database for reporting years 1989, 1991, 1993, 1995, and 1997 (EPA 2000a). 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 C-7). Carbon emission factors for equivalent fuels were obtained from Marland and Rotty (1984). Regulations require incinerators to achieve at least 99.99 percent destruction of organics; this formed the basis for assuming the fraction of carbon oxidized. A least-squares linear regression from the time series 1989 through 1997 was used to estimate emissions for 1998.

⁶ [42 U.S.C. §6924, SDWA §3004]

Table C-7: 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

Energy Recovery

The amount of fuel feedstocks that are combusted for energy recovery was estimated from data included in EIA's Manufacturers Energy Consumption Survey (MECS) for 1998 (EIA 2001b). Fuel feedstocks may be combusted for energy recovery 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 byproducts that have a high energy content. The chemical industry and many downstream industries are energy-intensive, and therefore unreacted feedstocks or byproducts of production may be combusted for energy recovery in industrial boilers. Also, hazardous waste regulations provide a strong incentive—and in some cases require—burning of organic wastes generated from chemical production processes. Combustion of hazardous waste without energy recovery is referred to as “incineration,” and is discussed separately in this Annex.

MECS data 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; 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., byproducts of the iron and steel production process) is addressed in the Iron and Steel production section in the Industrial Processes chapter. Consumption of refinery still gas and “other” fuels in the refinery sector 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 discussion. The remaining categories of fuels included in the 1998 MECS data (Table C-8) including waste gas; waste oils, tars, and related materials; and other uncharacterized fuels are assumed to be petrochemical feedstocks burned for energy recovery. The conversion factors listed in Annex A were used to convert the Btu values for each fuel feedstock to Tg CO₂. Petrochemical feedstocks combusted for energy recovery corresponded to 41.1 Tg CO₂ Eq. in 1998.

Table C-8: Summary of 1998 MECS Data for Other Fuels used in Manufacturing/Energy Recovery (Trillion Btu)

Subsector and Industry	NAICS Code	Waste Gas ^b	Waste Oils/Tars ^c	Refinery Still Gas ^d	Net Steam ^e	Other Fuels ^{f,g}
Printing and Related Support	323	0	1	0	0	0
Petroleum and Coal Products	324	0	1	1399	0	324 ^a
Chemicals	325	416	16	0	194	118 ^a
Plastics and Rubber Products	326	0	0	0	0	0
Nonmetallic Mineral Products	327	2	9	0	0	14
Primary Metals	331	2	2	0	0	22
Fabricated Metal Products	332	1	0	0	0	0
Machinery	333	0	1	0	0	0
Computer and Electronic Products	334	0	0	0	0	0
Electrical Equipment, Appliances, Components	335	1	1	0	0	0
Transportation Equipment	336	1	2	0	0	0
Total		423	33	1399	194	478
Carbon Content (Tg/QBTU)		18.1	20.6	17.5	0	19.4
Fraction Oxidized		99%	99%	99%	0%	99%
Total Carbon (Tg)		7.6	0.7	24.2	0.0	9.2
Total Carbon (Non-Refining)		7.6	0.7	0.0	0.0	3.0

^a EIA personal communication, 2001.

^b C content assumed to be naphtha <401F.

^c C content assumed to be asphalt and road oil.

^d Refinery “other” fuel consumption is reported elsewhere in the inventory and is excluded from the total carbon. The total non-refining total carbon excludes all “other” fuel consumption under NAICS Code 325 (Petroleum and Coal Products).

^e Net steam is reported elsewhere in the inventory and is excluded from the total carbon content estimate.

^f Assumed to be petrochemical feedstocks.

^g Includes net steam, except for NAICS Code 325 (Chemicals). Net steam for other sectors assumed to be negligible.

Note: Totals may not sum due to independent rounding.

Products

More carbon is found in products than in industrial releases or energy recovery. The principal types of products are plastics; synthetic rubber; synthetic fiber; carbon black; pesticides; soaps, detergents, and cleansers; 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 were taken from the American Plastics Council, as published in *Chemical & Engineering News* and through direct communication with the APC (APC 2000, Eldredge-Roebuck 2000). These data were organized by year and resin type (see Table C-9). A carbon content was assigned for each resin. These contents were based on molecular formulas and are listed in Table C-10 and Table C-11. 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 engineering resins and other resins, a weighted carbon content of 65 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 carbon was considered stored in products. However, an estimate of emissions related to the combustion of these plastics in the municipal solid waste stream can be found in the Waste Combustion section of the Energy chapter.

Table C-9: 1998 Plastic Resin Production (Tg dry weight) and Carbon Stored (Tg CO₂ Eq.)

Resin Type	1998 Production ^a	Carbon Stored
Epoxy	0.29	0.8
Polyester (Unsaturated)	0.78	1.8
Urea	1.17	1.5
Melamine	0.13	0.1
Phenolic	1.79	5.0
Low-Density Polyethylene (LDPE)	3.44	10.8
Linear Low-Density Polyethylene (LLDPE)	3.28	10.3
High Density Polyethylene (HDPE)	5.86	18.4
Polypropylene (PP)	6.27	19.7
Acrylonitrile-butadiene-styrene (ABS)	0.65	2.0
Styrene-acrylonitrile (SAN)	0.06	0.2
Other Styrenics	0.75	2.5
Polystyrene (PS)	2.83	9.6
Nylon	0.58	1.4
Polyvinyl chloride (PVC) ^b	6.58	9.3
Thermoplastic Polyester	2.01	4.6
Engineering Resins	1.25	3.0
All Other	3.88	9.4
Total	41.59	110.4

^a Includes production from Canada for ABS, SAN, PVC, PP, Phenolic, Urea, Melamine, and Thermoplastic Polyester

^b Includes copolymers

Note: Totals may not sum due to independent rounding.

Table C-10: Assigned Carbon Contents of Plastic Resins (by weight)

Resin Type	Carbon Content	Source of Carbon 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 *
Melamine	29%	Trimethylol melamine *
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 C-11)
Polyvinyl Chloride (PVC)	38%	Polyvinyl chloride
Thermoplastic Polyester	63%	Polyethylene terephthalate
Engineering Resins	66%	Weighted average of other resin production
All Other	66%	Weighted average of other resin production

*Does not include alcoholic hydrogens.

Table C-11: Major Nylon Resins and their Carbon Contents (by weight)

Resin	Carbon 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 annual consumption of synthetic rubber 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). Due to the fact that production data for synthetic rubber were unavailable, consumption was assumed to equal production. These data were organized by year and elastomer type. A carbon content was assigned for each elastomer type. These contents, based on stoichiometry, are listed in Table C-12. For the “Others” category, a weighted carbon content was calculated from total 1998 consumption data.

There were no emissive uses of rubber identified, so 100 percent of the carbon was assumed stored. However, emissions related to the combustion of scrap tires and rubber consumer goods can be found in the Waste Combustion section of the Energy chapter.

Table C-12: 1998 Rubber Consumption, Carbon Content, and Carbon Stored

Elastomer Type	1998 Consumption (Thousand Metric Tons) *	Carbon Content	Carbon Stored (Tg CO ₂ Eq.)
SBR Solid	908	91%	3.0
Polybutadiene	561	89%	1.8
Ethylene Propylene	320	86%	1.0
Polychloroprene	69	59%	0.1
NBR Solid	87	77%	0.2
Polyisoprene	78	88%	0.3
Others	369	88%	1.2
Total	2,392	-	7.7

* Includes consumption in Canada.

- Not applicable

Note: Totals may not sum due to independent rounding.

Synthetic Fibers

Annual synthetic fiber production data were obtained from the Fiber Economics Bureau, as published in Chemical & Engineering News and exhibited on the FiberSource website (FEB 2000). These data are organized by year and fiber type. For each fiber, a carbon content was assigned based on stoichiometry (see Table C-13). For polyester, the carbon content for poly(ethylene terephthalate) (PET) was used as a representative compound. For nylon, the average carbon 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' carbon accounting because much of their carbon is of biogenic origin. 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 carbon was considered stored. Note that emissions related to the combustion of textiles in municipal solid waste is accounted for under the Waste Combustion section of the Energy chapter.

Table C-13: 1998 Fiber Production, Carbon Content, and Carbon Stored

Fiber Type	Production (Tg)	Carbon Content	Carbon Stored (Tg CO ₂ Eq.)
Polyester	1.8	63%	4.1
Nylon	1.3	64%	3.0
Olefin	1.3	86%	4.1
Acrylic	0.2	68%	0.5
Total	4.6	-	11.7

- Not applicable

Note: Totals may not sum due to independent rounding

Carbon Black

Carbon black is a finely divided solid form of carbon produced from the partial oxidation of heavy oil fractions.⁷ It is used primarily in manufacture of tire treads and other abrasion resistant rubber products, but can also be used in pigments for paints and inks. In 1998, carbon black ranked 35th in chemical production in the United States with 1,610,280 metric tons produced (CMA 1999). Since carbon black is essentially pure carbon, its carbon content was assumed to be 100 percent. Also, since it is used in solid products and resists degradation, it was considered 100 percent stored. For 1998, carbon stored as a result of carbon black production was estimated to be 5.9 Tg CO₂ Eq.

Pesticides

Pesticide consumption data were obtained from the *1996/1997 Pesticides Industry Sales and Usage* (EPA 1999) report. The most recent data available were for 1995 through 1997, so it was assumed that 1998 consumption was equal to that of these years. Although some production data were available, consumption data were used because these data provided information on active ingredients. Active ingredient compound names and consumption weights were available for the top 25 agriculturally-used pesticides and top 9 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 carbon 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 carbon in the compound was assumed to be stored. All other pesticides were assumed to release their carbon to the atmosphere. Nearly one-third of total pesticide active ingredient consumption was not specified by chemical type in the *Sales and Usage* report (EPA 1999). This unspecified portion of the active ingredient consumption was treated as a single chemical and assigned a carbon content and a storage factor based on the weighted average of the known chemicals' values.

Table C-14: Active Ingredient Consumption in Pesticides (Million lbs.) and Carbon Emitted and Stored (Tg CO₂ Eq.)

Pesticide Use	Active Ingredient	Carbon Emitted	Carbon Stored
Agricultural Uses ^a	551.0	0.1	0.2
Non-Agricultural Uses ^b	84.5	+	+
Home & Garden	34.0	+	+
Industry/Gov't/Commercial	50.5	+	+
Other	334.5	0.1	0.1
Total	970.0	0.2	0.4

+ Less than 0.05 Tg CO₂ Eq.

^a1997 estimate (EPA 1999).

^b Approximate quantities, 1995/1996 estimates (EPA 1999).

⁷ Carbon black can also be produced from the cracking of natural gas, but this method is uncommon.

Note: Totals may not sum due to independent rounding.

Soaps, Shampoos, and Detergents

Cleansers – soaps, shampoos, and detergents—are among the major consumer products that may contain fossil carbon. All of the carbon in cleansers was assumed to be fossil derived, and, as cleansers eventually biodegrade, all of the carbon was assumed to be emitted. The first step in estimating carbon flows was to characterize the “ingredients” in a representative sampling 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 1997 Economic Census. The year 1997 was taken to be a representative year, as it is the most recent year for which comprehensive data were available.

Chemical formulae were used to determine carbon contents (as percentages) of the ingredients in the cleansers. Each product’s overall carbon content was then derived from the composition and contents of its ingredients. From these values the mean carbon 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 liquid⁸ cleanser categories, respectively.

Next, the total tonnage of cleansers was calculated (wet and dry combined). Multiplying the mean carbon content (21.9 percent) by this value yielded an estimate of the 1998 amount of carbon in cleansers of 4.9 Tg CO₂ Eq.

Uncertainty

There are several cross-cutting sources of uncertainty that pervade the characterization of a storage factor for feedstocks. The aggregate storage factor for petrochemical feedstocks, pentanes plus, liquefied petroleum gases, and natural gas is based on only a partial sampling of the releases and products derived from these fossil fuel feedstocks and imports and exports of petrochemical feedstocks. Including consideration of petrochemical feedstocks that are exported and feedstocks that are burned for energy recovery, approximately 90 percent of the carbon consumed across these fuel types for non-energy uses is accounted for. The remaining “unaccounted-for” carbon could have a variety of fates. For the purposes of this inventory, all of the unaccounted for carbon was assumed to be emitted, and using this assumption the overall storage factor is 60.9 percent. If the assumption had been made that the products which contained the unaccounted for carbon would store and emit carbon in the same ratio as the investigated releases and products, the overall storage factor would have been 67.9 percent, rather than 60.9 percent.

With respect to the “unaccounted for” carbon, there are uncertainties associated with the EIA data—which provide the initial carbon input—and the data for net imports and exports of feedstocks that could affect the calculation of the storage factor. To a lesser extent, there are uncertainties associated with the simplifying assumptions made for each end use category carbon estimate. Generally, the estimate for a product is subject to one or both of the following uncertainties:

- The value used for estimating the carbon content has been assumed or assigned based upon a representative compound.
- The split between carbon 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 carbon enters the non-energy mass balance. Some of the pathways that lead to emissions as CO₂ may take actually place on a time-scale of several years or decades. By

⁸ A density of 1.05 g/mL—slightly denser than water—was assumed for liquid cleansers.

attributing the emissions to the year in which the carbon 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 the estimate of the balance between storage and emissions is based on data for only for a single year, 1998. 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.

Imports/Exports

Import and export data for petrochemical feedstocks were obtained from EIA and the National Petroleum Refiners Association for the major categories of petrochemical feedstocks (EIA 2001a, NPRA 2001). The list of commodities for which imports and exports were analyzed is not comprehensive in tracking fossil fuel-derived feedstocks. In particular, the commodity codes used for the analysis do not track many secondary products or even some primary fossil fuel-derived products (e.g., the NPRA list of commodity codes includes polyethylene and polypropylene but not polystyrene, which is also a fossil fuel-derived commodity). Based on a limited screening analysis of additional relevant commodity codes, it appears that the current approach is likely to underestimate net exports of carbon. All unaccounted for carbon is currently assumed to be emitted. If net exports are higher than calculated here, the “missing” carbon would be lower, and thus emissions would be correspondingly lower.

Oxidation Factors

Oxidation factors have been applied to non-energy uses of petrochemical feedstocks in the same manner as for energy uses. However, 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 carbon. 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 carbon emissions from non-energy uses.

TRI

The major uncertainty in using the TRI data are the possibility of double counting of 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 carbon 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.

NMVOCs (Solvent Evaporation and Industry)

The principal sources of uncertainty in estimating CO₂ emissions from solvent evaporation and industry are in the estimates of total NMVOC emissions and in the application of factors for the carbon content of these emissions. 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 carbon 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 carbon content for industrial emissions has more uncertainty, however, as it is calculated from the average carbon content of an average volatile organic compound based on the list of the most abundant measured NMVOCs provided in EPA (2000b).

Hazardous Waste

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 carbon 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. Carbon emission estimates from hazardous waste should be considered central value estimates that are likely to be accurate to within ± 50 percent.

Energy Recovery

The amount of feedstocks combusted for energy recovery was estimated from data included in the Manufacturers Energy Consumption Survey (MECS) for 1998 (EIA 2001b). MECS is a comprehensive survey 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 1998 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.

Plastics

Uncertainty in the carbon storage estimate for plastics arises primarily from three factors. First, the production data for acrylonitrile-butadiene-styrene, styrene-acrylonitrile, polyvinyl chloride, polypropylene, phenolic, urea, melamine, and thermoplastic polyester resins include Canadian production and may overestimate the amount of plastic produced from U.S. fuel feedstocks. Second, the assumed carbon 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). Lastly, the assumption that all of the carbon 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.

Rubber

Similar to plastics, uncertainty results from using consumption data for the United States and Canada, rather than just domestic consumption, which may overestimate the amount of rubber produced from U.S. fuel feedstocks. There are also uncertainties as to the assignment of carbon 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 carbon content values is much narrower. Lastly, assuming that all of the carbon contained in rubber is stored ignores the possibility of volatilization or degradation during product lifetimes. However, the proportion of the total carbon that is released to the atmosphere during use is probably negligible.

Fibers

A small degree of uncertainty arises from the assignment of carbon content values; 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.

Pesticides

The largest source of uncertainty involves the assumption that a pesticide’s active ingredient carbon is either 0 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, delivery method, and harvesting practice. Another smaller source of uncertainty arises from the carbon content values applied to the unaccounted for portion of active ingredient. Carbon contents vary widely among pesticides, from 7 to 72 percent, and the remaining pesticides may have a chemical make-up that is very different from the 32 pesticides that have been examined.

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. According to EIA (2000d), approximately 100 Tg CO₂ Eq. has been used in the production of asphalt cement annually. Though minor amounts of carbon are emitted during production, asphalt has an overall carbon storage factor of almost 100 percent.

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 2000d), 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 carbon in asphalt roofing; it was assumed that it has the same fate as carbon in asphalt paving applications.

Methodology

A carbon storage factor was calculated for each type of asphalt paving. The fraction of carbon emitted by each asphalt type was multiplied by consumption data for asphalt paving (EPA 2000d, EIIP 1998) to come up with a weighted average carbon storage factor for asphalt as a whole.

The fraction of carbon emitted by HMA was determined by first calculating the organic emissions (volatile organic compounds [VOCs], carbon monoxide, polycyclic aromatic hydrocarbons [PAHs], hazardous air pollutants [HAPs], and phenol) from HMA paving, using emission factors reported in EPA (2000d) and total HMA production.⁹ The next step was to estimate the carbon content of the organic emissions. This calculation was based on stoichiometry for carbon monoxide (CO) and phenol, and an assumption of 85 percent carbon content for PAHs and HAPs. The carbon content of asphalt paving is a function of the proportion of asphalt cement in asphalt paving and the proportion of carbon in asphalt cement. For the former factor, a 5 percent asphalt cement content was assumed based on personal communication with an expert from the National Asphalt Paving Association (Connolly 2000). For the latter factor, all paving types were characterized as having a mass fraction of 85 percent carbon 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 99.99 percent of the carbon in asphalt cement was retained (i.e., stored), and less than 0.01 percent was emitted.

Cut-back asphalt is produced in three forms (i.e., rapid, medium and slow cure). All three forms emit carbon only from the volatile petroleum distillate used to thin the asphalt cement (EPA 1995). Because the petroleum distillates are not included in the EIA statistics for asphalt, the storage factor for cut-back is assumed to be 100 percent.

It was also assumed that there was no loss of carbon 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).

⁹ The emission factors are expressed as a function of asphalt paving tonnage (i.e., including the rock aggregate as well as the asphalt cement).

Data Sources

Data on asphalt and road oil consumption and carbon content factors were supplied by EIA. Hot mix asphalt production and emissions factors were obtained from “Hot Mix Asphalt Plants Emissions Assessment Report” from EPA’s *AP-42* (EPA 2000d) publication. The asphalt cement content of HMA was provided by Una Connolly of National Asphalt Paving Association (Connolly 2000). 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 1998). “Asphalt Paving Operation” *AP-42* (EPA 1995) provided the emissions source information used in the calculation of the carbon 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

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 carbon in a refractory form or physicochemical degradation and eventual release of CO₂ 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 HMA 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 carbon storage factor is minimal (on the order of 0.1 percent). Similarly, changes in the assumed carbon 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. However, because the carbon storage factor of each is 100 percent, use of more recent data would not affect the overall result.

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 (2000), the carbon content of U.S. production of lubricants in 1999 was approximately 28 Tg CO₂ Eq. 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 carbon storage factor was estimated to be 9 percent; thus, storage in 1999 was about 3 Tg CO₂ Eq.

Methodology

For each lubricant category, a storage factor was derived by identifying disposal fates and applying assumptions as to the disposition of the carbon for each practice. An overall lubricant carbon 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 15 years.¹⁰ The effect of these regulations and policies has been to restrict land filling and dumping, and to encourage collection of used oil. Given the relatively inexpensive price of crude oil, the economics have not favored re-refining—instead, most of the used oil that has been collected has been combusted.

¹⁰ 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 C-15 provides an estimated allocation of the fates of lubricant oils, along with an estimate of the proportion of carbon 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 CO₂, with correspondingly little long-term storage of carbon 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 CO₂ given that the releases are generally small and most of the oil is biodegraded. 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. Re-refining adds a recycling loop to the fate of oil; it was assumed that about 97 percent of the carbon in re-refined oil is ultimately oxidized. Because of the dominance of fates that result in eventual release as CO₂, only about 3 percent of the carbon in oil lubricants goes into long-term storage.

Table C-15: Commercial and Environmental Fate of Oil Lubricants (Percent)

Fate of Oil	Portion of Total	
	Oil	Carbon Stored
Combusted During Use	20	1
Not Combusted During Use	80	-
Combusted as Used Oil*	64	1
Dumped on the ground or in storm sewers	6	0
Landfilled	2	90
Re-refined into lube oil base stock and other products	8	3
Weighted Average	-	2.9

* (e.g., in boilers or space heaters)

- Not applicable

Greases

Table C-16 provides analogous estimates for lubricant greases. Unlike oils, grease is generally not combusted during use, and combustion for energy recovery and re-refining are 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, it was assumed that 90 percent and 50 percent of the carbon in landfilled and dumped grease, respectively, would be stored. The overall storage factor is 82 percent for grease.

Table C-16: Commercial and Environmental Fate of Grease Lubricants (Percent)

Fate of Grease	Total Grease	Carbon Stored
Combusted During Use	5	1
Not Combusted During Use	95	-
Landfilled	85.5	90
Dumped on the ground or in storm sewers	9.5	50
Weighted Average	-	81.8

- Not applicable

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. 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 percent.

Data Sources

The estimated volume of lubricants produced annually is based on statistics provided by EIA (2000), which conducts surveys of lubricating oil and grease consumption. Information on the value of lubricating oil and grease production was obtained from reports by the U.S. Census Bureau (1999).

The characterization of fate is based primarily on professional judgment of an EPA regulatory analyst with experience in used oil (Rinehart 2000). For the proportions combusted, one percent was assumed to remain un-

oxidized in combustion processes (EIIP 1999); for other fates, estimates are based on professional judgment. The assumption that landfilled oil and grease results in 90 percent storage is based on analogy with the persistence of petroleum in native petroleum-bearing strata, which are both anaerobic. The assumption that oil dumped on the ground or in storm sewers is completely degraded is based on the observation that land farming—application to soil—is one of the most frequently used methods for degrading refinery wastes. The lower degradation rate for grease is based on the observation that greases contain longer chain paraffins, which are more persistent. 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).

Uncertainty

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 carbon 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.

ANNEX D

Methodology for Estimating Emissions of CH₄, N₂O, and Ambient Air Pollutants from Stationary Combustion

Estimates of CH₄ and N₂O Emissions

Methane (CH₄) and nitrous oxide (N₂O) emissions from stationary combustion were estimated using IPCC emission factors and methods. Estimates were obtained by multiplying emission factors—by sector and fuel type—by fossil fuel and wood consumption data. This “top-down” methodology is characterized by two basic steps, described below. Data are presented in Table D-1 through Table D-5.

Step 1: Determine Energy Consumption by Sector and Fuel Type

Greenhouse gas emissions from stationary combustion activities were grouped into four sectors: industrial, commercial, residential, and electricity generation. For CH₄ and N₂O, estimates were based upon consumption of coal, gas, oil, and wood. Energy consumption data were obtained from EIA’s *Annual Energy Review* (EIA 2002), and adjusted from higher to lower heating values by multiplying by 0.9 for natural gas and wood and by 0.95 for coal and petroleum fuel. This is a simplified convention used by the International Energy Agency. Table D-1 provides annual energy consumption data for the years 1990 through 2001.

Step 2: Determine the Amount of CH₄ and N₂O Emitted

Activity data for each sector and fuel type were then multiplied by emission factors to obtain emission estimates. Emission factors were taken from the *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997). Table D-2 provides emission factors used for each sector and fuel type.

Estimates of NO_x, CO, and NMVOC Emissions

For ambient air pollutants, the major source categories included were those identified in EPA (2003): coal, fuel oil, natural gas, wood, other fuels (i.e., bagasse, liquefied petroleum gases, coke, coke oven gas, and others), and stationary internal combustion, which includes emissions from internal combustion engines not used in transportation. EPA (2003) periodically estimates emissions of NO_x, CO, and NMVOCs by sector and fuel type using a “bottom-up” estimating procedure. In other words, the emissions were calculated either for individual sources (e.g., industrial boilers) or for many sources combined, using basic activity data (e.g., fuel consumption or deliveries, etc.) as indicators of emissions. EPA (2003) projected emissions for years subsequent to their bottom-up estimates. The national activity data used to calculate the individual categories were obtained from various sources. Depending upon the category, these activity data may include fuel consumption or deliveries of fuel, tons of refuse burned, raw material processed, etc. Activity data were used in conjunction with emission factors that relate the quantity of emissions to the activity.

Table D-3 through Table D-5 present ambient air pollutant emission estimates for 1990 through 2001.

The basic calculation procedure for most source categories presented in EPA (2003) is represented by the following equation:

$$E_{p,s} = A_s \times EF_{p,s} \times (1 - C_{p,s}/100)$$

Where:

E	=	emissions
p	=	pollutant
s	=	source category
A	=	activity level
EF	=	emission factor
C	=	percent control efficiency

The EPA currently derives the overall emission control efficiency of a category from a variety of sources, including published reports, the 1985 National Acid Precipitation and Assessment Program (NAPAP) emissions inventory, and other EPA databases. The U.S. approach for estimating emissions of NO_x, CO, and NMVOCs from stationary combustion as described above is similar to the methodology recommended by the IPCC (IPCC/UNEP/OECD/IEA 1997).

Table D-1: Fuel Consumption by Stationary Combustion for Calculating CH₄ and N₂O Emissions (TBtu)

Fuel/End-Use Sector	1990	1995	1996	1997	1998	1999	2000	2001
Coal	18,019	19,187	20,123	20,615	20,790	20,800	21,754	21,819
Residential	26	17	17	16	13	14	12	12
Commercial	129	117	122	129	92	103	91	91
Industrial	1,612	1,577	1,545	1,555	1,459	1,394	1,421	2,017
Electricity Generation	16,245	17,466	18,429	18,905	19,216	19,279	20,220	19,689
Petroleum	7,853	6,967	7,396	7,484	7,333	7,196	7,371	7,503
Residential	1,263	1,356	1,489	1,448	1,322	1,452	1,493	1,473
Commercial	913	710	742	703	658	655	719	718
Industrial	4,024	3,676	3,989	4,020	3,588	3,419	3,543	3,549
Electricity Generation	1,278	755	817	927	1,306	1,211	1,144	1,280
Natural Gas	18,366	21,343	21,734	21,796	21,449	21,593	22,643	21,978
Residential	4,523	4,981	5,383	5,118	4,669	4,858	5,121	4,940
Commercial	2,701	3,113	3,244	3,302	3,098	3,130	3,301	3,331
Industrial	7,821	8,924	9,224	9,230	8,984	8,679	8,893	8,287
Electricity Generation	3,321	4,325	3,883	4,146	4,698	4,926	5,316	5,397
Wood	2,190	2,420	2,467	2,210	2,175	2,210	2,257	2,170
Residential	581	596	595	414	387	414	433	407
Commercial	39	46	50	52	48	52	53	43
Industrial	1,447	1,652	1,683	1,606	1,603	1,606	1,636	1,580
Electricity Generation	124	125	138	138	137	138	134	140

Note: Totals may not sum due to independent rounding.

Table D-2: CH₄ and N₂O Emission Factors by Fuel Type and Sector (g/GJ)¹

Fuel/End-Use Sector	CH ₄	N ₂ O
Coal		
Residential	300	1.4
Commercial	10	1.4
Industrial	10	1.4
Electricity Generation	1	1.4
Petroleum		
Residential	10	0.6
Commercial	10	0.6
Industrial	2	0.6
Electricity Generation	3	0.6
Natural Gas		
Residential	5	0.1
Commercial	5	0.1
Industrial	5	0.1
Electricity Generation	1	0.1
Wood		
Residential	300	4.0
Commercial	300	4.0
Industrial	30	4.0
Electricity Generation	30	4.0

¹ GJ (Gigajoule) = 10⁹ joules. One joule = 9.486×10⁻⁴ Btu

Table D-3: NO_x Emissions from Stationary Combustion (Gg)

Sector/Fuel Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Electricity Generation	6,045	5,914	5,901	6,034	5,956	5,792	5,595	5,697	5,653	5,139	4,819	4,437
Coal	5,119	5,043	5,062	5,211	5,113	5,061	5,081	5,120	4,932	4,394	4,115	3,782
Fuel Oil	200	192	154	163	148	87	107	132	202	177	146	148
Natural gas	513	526	526	500	536	510	259	289	346	396	382	330
Other Fuels ^a	NA	NA	NA	NA	NA	NA	5	6	24	33	36	37
Wood	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Internal Combustion	213	152	159	160	159	134	142	150	149	140	140	140
Industrial	2,754	2,703	2,786	2,859	2,855	2,852	2,859	2,813	2,768	2,586	2,411	2,393
Coal	530	517	521	534	546	541	490	487	475	500	473	496
Fuel Oil	240	215	222	222	219	224	203	196	190	200	162	147
Natural gas	1,072	1,134	1,180	1,207	1,210	1,202	1,092	1,079	1,066	926	881	875
Wood	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other Fuels ^a	119	117	115	113	113	111	109	103	104	105	106	111
Internal Combustion	792	720	748	783	767	774	965	948	933	855	789	764
Commercial	336	333	348	360	365	365	360	369	347	379	384	384
Coal	36	33	35	37	36	35	30	32	34	32	30	28
Fuel Oil	88	80	84	84	86	94	86	88	73	75	73	72
Natural gas	181	191	204	211	215	210	224	229	220	217	224	227
Wood	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other Fuels ^a	31	29	25	28	28	27	20	21	21	55	57	57
Residential	749	829	879	827	817	813	726	699	651	611	611	611
Coal ^b	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Fuel Oil ^b	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Natural Gas ^b	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Wood	42	45	48	40	40	44	27	27	27	34	30	30
Other Fuels ^a	708	784	831	787	777	769	699	671	624	577	582	582
Total	9,884	9,779	9,914	10,080	9,993	9,822	9,540	9,578	9,419	8,716	8,226	7,826

IE (Included elsewhere)

NO (Not occurring)

^a "Other Fuels" include LPG, waste oil, coke oven gas, coke, and non-residential wood (EPA 2003).^b Coal, fuel oil, and natural gas emissions are included in the "Other Fuels" category (EPA 2003).

Note: Totals may not sum due to independent rounding.

Table D-4: CO Emissions from Stationary Combustion (Gg)

Sector/Fuel Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Electricity Generation	329	317	318	329	335	338	369	385	409	562	455	445
Coal	213	212	214	224	224	227	228	233	220	233	230	223
Fuel Oil	18	17	14	15	13	9	11	13	17	45	28	28
Natural gas	46	46	47	45	48	49	72	76	88	188	100	93
Other Fuels ^a	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Wood	NA	NA	NA	NA	NA	NA	7	8	30	30	33	33
Internal Combustion	52	41	43	46	50	52	52	54	54	65	65	68
Industrial	798	835	867	946	944	958	1,079	1,055	1,044	1,089	1,053	1,071
Coal	95	92	92	92	91	88	100	99	96	112	112	118
Fuel Oil	67	54	58	60	60	64	49	47	46	54	45	43
Natural gas	205	257	272	292	306	313	308	308	305	347	338	345
Wood	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other Fuels ^a	253	242	239	259	260	270	317	302	303	283	286	303
Internal Combustion	177	189	205	243	228	222	306	299	294	293	271	263
Commercial	205	196	204	207	212	211	122	126	122	146	147	149
Coal	13	13	13	14	13	14	13	13	14	15	14	13
Fuel Oil	16	16	16	16	16	17	17	18	15	16	16	16
Natural gas	40	40	46	48	49	49	58	59	57	76	79	80
Wood	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other Fuels ^a	136	128	128	129	134	132	34	36	36	38	38	40
Residential	3,668	3,965	4,195	3,586	3,515	3,876	2,364	2,361	2,352	3,144	2,508	2,503
Coal ^b	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Fuel Oil ^b	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Natural Gas ^b	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Wood	3,430	3,711	3,930	3,337	3,272	3,628	2,133	2,133	2,133	2,928	2,292	2,292
Other Fuels ^a	238	255	265	249	243	248	231	229	220	217	216	211
Total	4,999	5,313	5,583	5,068	5,007	5,383	3,935	3,927	3,927	4,941	4,163	4,169

IE (Included elsewhere)

NO (Not occurring)

^a "Other Fuels" include LPG, waste oil, coke oven gas, coke, and non-residential wood (EPA 2003).

^b Coal, fuel oil, and natural gas emissions are included in the "Other Fuels" category (EPA 2003).

Note: Totals may not sum due to independent rounding.

Table D-5: NMVOC Emissions from Stationary Combustion (Gg)

Sector/Fuel Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Electricity Generation	43	40	40	41	41	40	44	47	51	50	58	57
Coal	25	25	25	26	26	26	25	26	26	25	28	27
Fuel Oil	5	5	4	4	4	2	3	4	5	4	5	5
Natural gas	2	2	2	2	2	2	7	7	9	9	13	13
Other Fuels ^a	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Wood	NA	NA	NA	NA	NA	NA	+	+	1	2	2	2
Internal Combustion	11	9	9	9	9	9	9	10	10	10	11	11
Industrial	165	177	169	169	178	187	163	160	159	159	152	152
Coal	7	5	7	5	7	5	6	6	6	9	9	10
Fuel Oil	11	10	11	11	11	11	8	7	7	10	9	8
Natural gas	52	54	47	46	57	66	54	54	54	53	52	52
Wood	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other Fuels ^a	46	47	45	46	45	45	33	31	31	26	26	28
Internal Combustion	49	61	60	60	58	59	63	62	61	61	56	54
Commercial	18	18	20	22	21	21	22	22	21	37	38	38
Coal	1	1	1	1	1	1	1	1	1	1	1	1
Fuel Oil	3	2	3	3	3	3	3	3	3	4	4	4
Natural gas	7	8	9	10	10	10	13	13	12	15	15	15
Wood	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other Fuels ^a	8	7	7	8	8	8	5	5	5	18	19	19
Residential	686	739	782	670	657	726	788	787	786	1,066	839	839
Coal ^b	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Fuel Oil ^b	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Natural Gas ^b	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Wood	651	704	746	633	621	689	756	756	756	1,039	812	812
Other Fuels ^a	35	35	36	36	36	37	33	32	30	27	27	27
Total	912	975	1,011	901	898	973	1,018	1,016	1,016	1,312	1,088	1,087

IE (Included elsewhere)

NO (Not occurring)

^a "Other Fuels" include LPG, waste oil, coke oven gas, coke, and non-residential wood (EPA 2003).

^b Coal, fuel oil, and natural gas emissions are included in the "Other Fuels" category (EPA 2003).

Note: Totals may not sum due to independent rounding.

ANNEX E

Methodology for Estimating Emissions of CH₄, N₂O, and Ambient Air Pollutants from Mobile Combustion and Methodology for and Supplemental Information on Transportation-Related GHG Emissions

Estimates of CH₄ and N₂O Emissions

Greenhouse gas emissions from mobile combustion other than CO₂ are reported by transport mode (e.g., road, rail, aviation, and waterborne), vehicle type, and fuel type. The EPA does not systematically track emissions of CH₄ and N₂O; therefore, estimates of these gases were developed using a methodology similar to that outlined in the *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997).

Activity data were obtained from a number of U.S. government agencies and other publications. Depending on the category, these basic activity data included such information as fuel consumption, fuel deliveries, and vehicle miles traveled (VMT).

Methodology for Highway Gasoline and Diesel Vehicles

Step 1: Determine Vehicle Miles Traveled by Vehicle Type, Fuel Type, and Model Year

VMT by vehicle type were obtained from the Federal Highway Administration's (FHWA) *Highway Statistics* (FHWA 1996 through 2002). As these vehicle categories are not fuel-specific, VMT for each vehicle type was disaggregated by fuel type using fuel economy and consumption data, so that the appropriate emission factors could be applied. First, fuel economy and consumption data from FHWA's *Highway Statistics* were disaggregated by fuel type using a number of sources, including the Department of Energy's (DOE) *Transportation Energy Data Book* (DOE 1993 through 2002), FHWA's *Highway Statistics* (FHWA 1996 through 2002), EPA and DOE's *Fuel Economy 2001 Datafile* (EPA/DOE 2001), and the *Vehicle Inventory and Use Survey* (Census 2000). These data were used to distribute national VMT estimates across vehicle categories,¹ including passenger cars (0-8500 GVWR), light duty trucks (0-8500 GVWR), heavy duty vehicles (>8500 GVWR), and motorcycles.² For a more detailed description of vehicle types, see Technical Description of Mobile 6.2 and Guidance on Its Use for Emission Inventory Preparation Draft Report (EPA420-R-02-011).

VMT for alternative fuel and advanced technology vehicles (henceforth known simply as AFVs) were calculated separately, and the methodology is explained in the following section on AFVs. Since the VMT estimates from FHWA include total VMT in the United States, it was necessary to subtract VMT from AFVs from this total. National VMT data for gasoline and diesel highway vehicles are presented in Table E-1 and Table E-2, respectively. Total VMT for each highway category (i.e., gasoline passenger cars, light-duty gasoline trucks, heavy-duty gasoline vehicles, diesel passenger cars, light-duty diesel trucks, heavy-duty diesel vehicles, and motorcycles) were distributed across 25 model years based on the VMT distribution by vehicle age shown in Table E-7. This distribution was derived by weighting the temporally fixed age distribution of the U.S. vehicle fleet according to vehicle registrations (Table E-5) by the average annual age-specific vehicle mileage accumulation of U.S. vehicles (Table E-6). Both were obtained from EPA's MOBILE6 model (EPA 2000).

¹ This methodology is presented in more detail in ICF Consulting (2001).

² GVWR is gross vehicle weight rating (i.e. vehicle weight plus weighted cargo capacity).

Step 2: Allocate VMT Data to Control Technology Type

VMT by vehicle type for each model year were distributed across various control technologies as shown in Table E-9 through Table E-12. The categories “EPA Tier 0” and “EPA Tier 1” were substituted for the early three-way catalyst and advanced three-way catalyst categories, respectively, as defined in the *Revised 1996 IPCC Guidelines*. EPA Tier 0, EPA Tier 1, and LEV actually refer to U.S. emission regulations, rather than control technologies; however, each does correspond to particular combinations of control technologies and engine design. EPA Tier 1 and its predecessor EPA Tier 0 both apply to vehicles equipped with three-way catalysts. The introduction of “early three-way catalysts,” and “advanced three-way catalysts,” as described in the *Revised 1996 IPCC Guidelines*, roughly correspond to the introduction of EPA Tier 0 and EPA Tier 1 regulations (EPA 1998).³

Control technology assignments for light and heavy-duty conventional fuel vehicles for model years 1972 (when regulations began to take effect) through 1995 were estimated in EPA (1998). Assignments for 1998 through 2001 were determined using confidential engine family sales data submitted to EPA (EPA 2002b). Vehicle classes and emission standard tiers to which each engine family was certified were taken from annual certification test results and data (EPA 2002a). This was used to determine the fraction of sales of each class of vehicle that met EPA Tier 0, EPA Tier 1, and LEV standards. Assignments for 1996 and 1997 were estimated based on the fact that EPA Tier 1 standards for light-duty vehicles were fully phased in by 1996.

Step 3: Determine CH₄ and N₂O Emission Factors by Vehicle, Fuel, and Control Technology Type

CH₄ emission factors were primarily obtained from the IPCC (IPCC/UNEP/OECD/IEA 1997), which were derived from the EPA’s MOBILE5a mobile source emissions model (EPA 1997). The MOBILE5a model uses information on ambient temperature, diurnal temperature range, altitude, vehicle speeds, national vehicle registration distributions, gasoline volatility, emission control technologies, fuel composition, and the presence or absence of vehicle inspection/maintenance programs in order to produce these factors. Since MOBILE5a, many heavy-duty gasoline vehicles are now compliant with EPA Tier 1 and LEV emission standards. Methane emission factors for these vehicles were determined using emission factors from the California Air Resources Board (CARB 2000).

Emissions of N₂O have not been extensively studied and are currently not well characterized. The limited number of studies that have been performed on highway vehicle emissions of N₂O have shown that emissions are generally greater from vehicles with catalytic converter systems than those without such controls, and greater from aged than from new catalysts. These systems control tailpipe emissions of NO_x (i.e., NO and NO₂) by catalytically reducing NO_x to N₂. Sub-optimal catalyst performance, caused by as yet poorly understood factors, results in incomplete reduction and the conversion of some NO_x to N₂O rather than to N₂. Fortunately, newer vehicles with catalyst and engine designs meeting the more recent EPA Tier 1 and LEV standards have shown reduced emission rates of both NO_x and N₂O compared with earlier catalyst designs.

In order to better characterize the process by which N₂O is formed by catalytic controls and to develop a more accurate national emission estimate, the EPA’s Office of Transportation and Air Quality—at its National Vehicle and Fuel Emissions Laboratory (NVFEL)—conducted a series of tests in order to measure emission rates of N₂O from used EPA Tier 1 and LEV gasoline-fueled passenger cars and light-duty trucks equipped with catalytic converters. These tests and a review of the literature were used to develop the emission factors for N₂O (EPA 1998). The following references were used in developing the N₂O emission factors for gasoline-fueled highway passenger cars presented in Table E-13:

³ For further description, see “Definitions of Emission Control Technologies and Standards” section of this annex.

- *LEVs*. Tests performed at NVFEL (EPA 1998)⁴
- *EPA Tier 1*. Tests performed at NVFEL (EPA 1998)
- *EPA Tier 0*. Smith and Carey (1982), Barton and Simpson (1994), and one car tested at NVFEL (EPA 1998)
- *Oxidation Catalyst*. Smith and Carey (1982), Urban and Garbe (1980)
- *Non-Catalyst*. Prigent and de Soete (1989), Dasch (1992), and Urban and Garbe (1979)

Nitrous oxide emission factors for other types of gasoline-fueled vehicles—light-duty trucks, heavy-duty vehicles, and motorcycles—were estimated by adjusting the factors for gasoline passenger cars, as described above, by their relative fuel economies. This adjustment was performed using miles per gallon data derived from (DOE 1993 through 2002), (FHWA 1996 through 2002), (EPA, DOE 2001), and (Census 2000) shown in Table E-13. Data from the literature and tests performed at NVFEL support the conclusion that light-duty trucks and other vehicles have higher emission rates than passenger cars. However, the use of fuel-consumption ratios to determine emission factors is considered an estimate, with a moderate level of uncertainty.

Nitrous oxide emission factors for heavy-duty gasoline vehicles compliant with EPA Tier 1 and LEV emission standards were estimated from the ratio of NO_x emissions to N₂O emissions for EPA Tier 0 heavy-duty gasoline trucks.

The resulting N₂O emission factors employed for gasoline highway vehicles are lower than the U.S. default values presented in the *Revised 1996 IPCC Guidelines*, but are higher than the European default values, both of which were published before the more recent tests and literature review conducted by the NVFEL. The U.S. defaults in the *Guidelines* were based on three studies that tested a total of five cars using European rather than U.S. test procedures.

Nitrous oxide emission factors for diesel highway vehicles were taken from the European default values found in the *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997). Little data addressing N₂O emissions from U.S. diesel-fueled vehicles exists, and in general, European countries have had more experience with diesel-fueled vehicles.

Compared to regulated tailpipe emissions, relatively little data are available to estimate emission factors for N₂O. Nitrous oxide is not a regulated ambient air pollutant, and measurements of it in automobile exhaust have not been routinely collected. Further testing would be needed to reduce the uncertainty in N₂O emission factors for all classes of vehicles, using realistic driving regimes, environmental conditions, and fuels.

Step 4: Determine the Amount of CH₄ and N₂O Emitted by Vehicle, Fuel, and Control Technology Type

VMT for each highway category for each year were first converted to vehicle kilometers traveled (VKT) so that emission factors could be applied. Emissions of CH₄ and N₂O were then calculated by multiplying total VKT by vehicle, fuel, and control technology type by the emission factors developed in Step 3.

⁴ LEVs are assumed to be operated using low-sulfur fuel (i.e., Indolene at 24 ppm sulfur). All other NVFEL tests were performed using a standard commercial fuel (CAAB at 285 ppm sulfur). Emission tests by NVFEL have consistently exhibited higher N₂O emission rates from higher sulfur fuels on EPA Tier 1 and LEV vehicles.

Methodology for Alternative Fuel Vehicles (AFVs)

Step 1: Determine Vehicle Miles Traveled by Vehicle and Fuel Type

VMT for alternative fuel and advanced technology vehicles were calculated from the Energy Information Administration Data Tables (EIA 2002a). Alternative Fuels include Compressed Natural Gas (CNG), Liquefied Petroleum Gas (LPG), Ethanol, Methanol, and Electric Vehicles (battery powered). Most of the vehicles that use these fuels run an Internal Combustion Engine (ICE) powered by the alternative fuel, although many of the vehicles can run on either the alternative fuel or gasoline (or diesel), or some combination. The data obtained include vehicle fuel use and total number of vehicles in use from 1992 through 2001. Fuel economy for each vehicle type and calendar year was determined by estimating the gasoline equivalent fuel economy for each technology. Energy economy ratios (the ratio of the gasoline equivalent fuel economy of a given technology to that of conventional gasoline or diesel vehicles) were taken from full fuel cycle studies done for the California Air Resources Board (Unnasch and Browning, 2000). These were used to estimate fuel economy in miles per gasoline gallon equivalent for each alternative fuel and vehicle type. Energy use per fuel type was then divided among the various weight categories and vehicle technologies that would use that fuel. Total VMT per vehicle type for each calendar year was then determined by dividing the energy usage by the fuel economy. Average vehicle VMT was then calculated by dividing total VMT per vehicle type by the number of vehicles. Average vehicle VMT for each vehicle type was checked against the Federal Highway Administration Highway Statistics Series for each calendar year (FHWA 1996 through 2002). Note that for AFVs capable of running on both/either traditional and alternative fuels, the VMT given reflects only those miles driven that were powered by the alternative fuel. Overall VMT estimates for AFVs are shown in Table E-3, while more detailed estimates of VMT are shown in Table E-4.

Step 2: Determine CH₄ and N₂O Emission Factors by Vehicle and Alternative Fuel Type

Limited data exists on N₂O and CH₄ emission factors for alternative fuel vehicles, and most of this data is for older emission control technologies. Several studies have estimated emission factors for alternative fuel vehicles, but similarly do not cover all of the various technologies and weight classes. Light-duty alternative fuel vehicle emission factors are estimated in Argonne National Laboratory's GREET 1.5 – Transportation Fuel Cycle Model (Wang 1999). In addition, Lipman and Delucchi estimate emission factors for some light and heavy-duty alternative fuel vehicles (Lipman and Delucchi 2002). The approach taken here is to calculate CH₄ emissions from actual test data and determine N₂O emissions from NO_x emissions from the same tests. Since it is likely that most alternative fuel vehicles use the same or similar catalysts to their conventional counterpart, the amount of N₂O emissions will depend upon the amount of oxides of nitrogen emissions that the engine produces. Based upon gasoline data for EPA Tier 1 cars, the tailpipe NO_x to N₂O ratio is 5.75. Lipman and Delucchi (2002) found NO_x to N₂O ratios for light-duty alternative fuel vehicles with three-way catalyst systems to vary from 3 to 5.5 for older technology.

Methane emission factors for light-duty vehicles were taken from the Auto/Oil Air Quality Improvement Research Program dataset (CRC 1997). This dataset provided CH₄ emission factors for all light-duty vehicle technologies except for LPG (propane). Light-duty propane emission factors were determined from reports on LPG-vehicle emissions from the California Air Resources Board (Brasil and McMahon, 1999) and the University of California Riverside (Norbeck, et al., 1998).

Heavy-duty emission factors for alternative fuel vehicles were determined from test data using the West Virginia University mobile dynamometer (DOE 2002a). Emission factors were determined based on the ratio of total hydrocarbon emissions to CH₄ emissions found for light-duty vehicles using the same fuel. Nitrous oxide emissions for heavy-duty engines were calculated from NO_x emission results using a NO_x to N₂O ratio of 50, which is more typical for heavy-duty engines with oxidation catalysts. These emission factors are shown in Table E-14.

Step 3: Determine the Amount of CH₄ and N₂O Emitted by Vehicle and Fuel Type

Emissions of CH₄ and N₂O were calculated by multiplying total VMT by vehicle and fuel type (Step 1) by the appropriate emission factors (Step 2).

Methodology for Non-Highway Mobile Sources

Activity data for non-highway vehicles were based on annual fuel consumption statistics by transportation mode and fuel type and are shown in Table E-8. Consumption data for distillate and residual fuel oil by ships and boats (i.e., vessel bunkering), construction equipment, and farm equipment and residual fuel use by locomotives were obtained from EIA's Fuel Oil and Kerosene Sales (1991 through 2002). In the case of ships and boats, vessel bunkering data from U.S. territories (EIA 2002c) were added to domestic consumption, and this total was reduced by the amount of fuel used for international bunkers.⁵ Annual diesel consumption for Class I railroad locomotives was obtained from AAR (2001), while consumption by Class II and III railroad locomotives was provided by Benson (2002). Data on the consumption of jet fuel and aviation gasoline in aircraft were obtained from EIA (2002b), as described under Annex A: CO₂ from Fossil Fuel Combustion, and were reduced by the amount allocated to international bunker fuels. Data on the consumption of motor gasoline by ships and boats, construction equipment, and farm equipment were drawn from FHWA (1996 through 2002).

Emissions of CH₄ and N₂O from non-highway mobile sources were calculated by multiplying U.S. default emission factors in the *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997) by activity data for each source type (see Table E-15).

Table E-16 and Table E-17 provide complete emissions of CH₄ and N₂O emissions, respectively, for 1990 through 2001.

Estimates of NO_x, CO, and NMVOC Emissions

The emission estimates of NO_x, CO, and NMVOCs for mobile combustion were taken directly from the EPA's National Emission Inventory (NEI) Air Pollutant Emission Trends web site (EPA 2003). This EPA report provides emission estimates for these gases by sector and fuel type using a "top down" estimating procedure whereby emissions were calculated using basic activity data, such as amount of fuel delivered or miles traveled, as indicators of emissions.

Table E-18 through Table E-20 provide complete emissions estimates for 1990 through 2001.

Table E-1: Vehicle Miles Traveled for Gasoline Highway Vehicles (10⁹ Miles)

	Passenger	Light-Duty	Heavy-Duty	
Year	Cars	Trucks	Vehicles	Motorcycles
1990	1395.4	558.0	29.8	8.7
1991	1346.1	631.9	31.7	8.8
1992	1359.6	687.4	30.7	9.1
1993	1363.0	724.1	29.8	9.3
1994	1394.8	742.3	30.2	9.5
1995	1426.8	767.0	30.1	9.8
1996	1458.7	792.6	30.2	9.9
1997	1491.4	824.9	30.1	10.1
1998	1538.9	842.1	30.6	10.3
1999	1558.8	873.5	30.8	10.6
2000	1590.1	894.5	29.6	10.5
2001	1609.6	908.8	28.5	9.5

Source: Derived from FHWA (1996 through 2002).

⁵ See International Bunker Fuels section of the Energy Chapter.

Table E-2: Vehicle Miles Traveled for Diesel Highway Vehicles (10⁹ Miles)

Year	Passenger Cars	Light-Duty Trucks	Heavy-Duty Vehicles
1990	13.7	15.4	121.2
1991	12.4	16.4	122.7
1992	12.3	18.5	127.6
1993	12.1	20.4	135.1
1994	11.8	21.2	145.4
1995	11.2	21.9	153.4
1996	10.8	22.8	158.3
1997	10.8	24.6	167.0
1998	10.3	24.7	171.5
1999	9.9	26.0	178.3
2000	9.6	26.9	182.0
2001	9.1	27.3	184.5

Source: Derived from FHWA (1996 through 2002).

Table E-3: Vehicle Miles Traveled for Alternative Fuel Highway Vehicles (10⁹ Miles)

Year	Passenger Cars	Light-Duty Trucks	Heavy-Duty Vehicles
1990	0.1	1.2	0.9
1991	0.1	1.1	0.9
1992	0.1	1.0	0.8
1993	0.2	1.2	1.1
1994	0.2	1.2	1.0
1995	0.3	1.1	1.0
1996	0.3	1.2	1.1
1997	0.3	1.3	1.2
1998	0.4	1.4	1.3
1999	0.4	1.6	1.3
2000	0.6	1.5	1.5
2001	0.8	1.8	1.8

Source: Derived from EIA (2002a).

Table E-4: Detailed Vehicle Miles Traveled for Alternative Fuel Highway Vehicles (10⁶ Miles)

Vehicle Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Light-Duty Cars	97.4	110.7	133.8	194.1	228.7	253.5	289.9	348.1	381.4	447.2	602.6	763.1
Methanol-Flex Fuel ICE	0.0	9.0	21.8	45.8	66.5	58.3	51.5	46.4	36.5	31.8	18.2	13.8
Ethanol-Flex Fuel ICE	0.0	0.1	0.1	0.3	0.4	1.0	3.8	7.2	9.8	21.2	41.3	51.6
CNG ICE	10.7	13.5	15.9	22.5	26.5	35.3	46.4	61.5	73.0	87.7	100.5	132.3
CNG Bi-fuel	23.1	27.1	34.4	50.7	60.4	84.7	108.8	148.2	171.8	207.1	234.4	310.5
LPG ICE	7.2	6.7	6.1	8.1	7.5	7.1	7.4	7.4	7.7	7.9	8.4	8.8
LPG Bi-fuel	56.4	54.3	51.0	59.8	57.8	54.7	57.7	57.7	59.5	60.4	62.7	64.0
NEVs	0.0	0.0	3.9	6.1	8.3	10.7	12.6	17.2	20.2	27.0	46.4	70.2
Electric	0.0	0.0	0.5	0.9	1.2	1.6	1.8	2.5	3.0	4.1	7.1	10.7
Electric-Gasoline Hybrid	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	83.7	101.3
Light-Duty Trucks	1,222.6	1,115.3	980.4	1,238.4	1,183.1	1,138.7	1,204.5	1,308.6	1,394.1	1,492.9	1,646.3	1,816.2
Ethanol-Flex Fuel ICE	0.0	0.2	0.3	0.8	1.4	3.2	11.8	22.4	30.8	67.4	129.9	164.5
CNG ICE	9.9	14.2	18.0	24.3	30.5	40.3	50.5	75.8	87.5	103.9	129.1	161.6
CNG Bi-fuel	22.9	27.0	30.4	39.1	48.1	60.3	75.0	139.2	164.9	195.6	227.2	284.1
LPG ICE	26.8	26.3	24.7	26.9	25.6	24.0	24.7	25.1	25.7	26.0	26.6	27.5
LPG Bi-fuel	1,162.9	1,047.7	905.9	1,145.8	1,075.6	1,008.3	1,039.3	1,041.7	1,080.0	1,092.9	1,121.4	1,160.2
Electric	0.0	0.0	1.0	1.5	2.0	2.6	3.2	4.4	5.3	7.1	12.1	18.2
Medium-Duty Trucks	192.9	176.5	159.7	198.4	187.3	179.2	190.2	195.7	200.1	204.6	221.3	251.9
CNG Bi-fuel	1.5	1.8	2.1	2.6	3.4	4.3	5.5	6.7	7.8	9.2	10.5	11.9
LPG ICE	16.4	16.2	15.6	17.2	16.6	15.6	16.8	17.3	17.8	18.1	19.6	22.4
LPG Bi-fuel	174.9	158.5	141.9	178.7	167.4	159.3	167.9	171.7	174.5	177.3	191.2	217.6
Heavy-Duty Trucks	632.7	619.7	600.9	780.7	743.5	726.3	765.7	842.0	863.1	903.7	997.2	1,175.8
Neat Methanol ICE	0.0	4.6	9.6	12.7	13.2	7.5	0.0	0.0	0.0	0.0	0.0	0.0
Neat Ethanol ICE	0.0	0.0	0.0	0.0	0.0	2.9	10.4	6.6	0.1	0.3	0.1	0.0
CNG ICE	14.2	18.2	22.9	29.6	31.6	51.2	68.6	88.4	96.5	123.8	139.2	176.4
LPG ICE	522.0	498.5	474.1	640.0	606.1	575.2	590.7	642.1	655.5	663.6	726.1	838.5
LPG Bi-fuel	96.5	98.3	93.6	94.8	88.4	83.9	89.3	96.5	98.8	100.3	114.1	136.2
LNG	0.0	0.0	0.7	3.6	4.3	5.6	6.7	8.3	12.1	15.7	17.7	24.8
Buses	90.5	86.4	83.6	111.7	112.1	122.7	145.9	184.7	201.6	232.5	269.9	327.7
Neat Methanol ICE	3.7	3.7	3.8	4.3	4.3	3.8	1.3	1.4	1.8	1.8	1.8	1.6
Neat Ethanol ICE	0.1	0.2	0.3	0.3	0.5	1.7	3.3	0.1	0.1	0.0	0.0	0.0
CNG ICE	17.1	19.3	21.5	27.2	29.7	44.3	62.4	97.0	107.5	134.9	160.3	195.2
LPG ICE	69.7	63.3	56.7	76.4	73.1	67.9	72.9	78.9	81.4	81.9	92.2	108.9
LNG	0.0	0.0	1.3	3.5	4.4	5.0	5.9	7.3	10.6	13.7	15.4	21.7
Electric	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.3
Total VMT	2,236.1	2,108.7	1,958.3	2,523.4	2,454.7	2,420.5	2,596.2	2,879.1	3,040.4	3,280.9	3,737.3	4,334.7

Source: Derived from EIA (2002a).

Table E-5: Age Distribution by Vehicle/Fuel Type for Highway Vehicles

Vehicle Age	LDGV	LDGT	HDGV	LDDV	LDDT	HDDV	MC ^a
1	5.3%	5.8%	4.9%	5.3%	5.9%	4.2%	14.4%
2	7.1%	7.6%	8.9%	7.1%	7.4%	7.8%	16.8%
3	7.1%	7.5%	8.1%	7.1%	6.9%	7.2%	13.5%
4	7.1%	7.3%	7.4%	7.1%	6.4%	6.7%	10.9%
5	7.0%	7.1%	6.8%	7.0%	6.0%	6.2%	8.8%
6	7.0%	6.8%	6.2%	7.0%	5.6%	5.8%	7.0%
7	6.9%	6.5%	5.6%	6.9%	5.2%	5.3%	5.6%
8	6.8%	6.1%	5.1%	6.8%	4.8%	5.0%	4.5%
9	6.6%	5.7%	4.7%	6.6%	4.5%	4.6%	3.6%
10	6.3%	5.2%	4.3%	6.3%	4.2%	4.3%	2.9%
11	5.9%	4.7%	3.9%	5.9%	3.9%	4.0%	2.3%
12	5.4%	4.2%	3.6%	5.4%	3.6%	3.7%	9.7%
13	4.6%	3.6%	3.3%	4.6%	3.4%	3.4%	-
14	3.6%	3.1%	3.0%	3.6%	3.2%	3.2%	-
15	2.9%	2.6%	2.7%	2.9%	2.9%	2.9%	-
16	2.3%	2.2%	2.5%	2.3%	2.7%	2.7%	-

17	1.8%	1.8%	2.3%	1.8%	2.5%	2.5%	-
18	1.4%	1.4%	2.1%	1.4%	2.4%	2.4%	-
19	1.1%	1.2%	1.9%	1.1%	2.2%	2.2%	-
20	0.9%	1.1%	1.7%	0.9%	2.1%	2.0%	-
21	0.7%	1.1%	1.6%	0.7%	1.9%	1.9%	-
22	0.6%	1.0%	1.5%	0.6%	1.8%	1.8%	-
23	0.4%	1.0%	1.3%	0.4%	1.7%	1.6%	-
24	0.4%	0.9%	1.2%	0.4%	1.6%	1.5%	-
25+	1.0%	4.6%	5.4%	1.0%	7.3%	7.2%	-
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Source: EPA (2000).

^a Because of a lack of data, all motorcycles over 12 years old are considered to have the same emissions and travel characteristics, and therefore are aggregated together.

Table E-6: Annual Age-specific Vehicle Mileage Accumulation of U.S. Vehicles (Miles)

Vehicle Age	LDGV	LDGT	HDGV	LDDV	LDDT	HDDV	MC^a
1	14,910	19,906	20,218	14,910	26,371	28,787	4,786
2	14,174	18,707	18,935	14,174	24,137	26,304	4,475
3	13,475	17,559	17,100	13,475	22,095	24,038	4,164
4	12,810	16,462	16,611	12,810	20,228	21,968	3,853
5	12,178	15,413	15,560	12,178	18,521	20,078	3,543
6	11,577	14,411	14,576	11,577	16,960	18,351	3,232
7	11,006	13,454	13,655	11,006	15,533	16,775	2,921
8	10,463	12,541	12,793	10,463	14,227	15,334	2,611
9	9,947	11,671	11,987	9,947	13,032	14,019	2,300
10	9,456	10,843	11,231	9,456	11,939	12,817	1,989
11	8,989	10,055	10,524	8,989	10,939	11,719	1,678
12	8,546	9,306	9,863	8,546	10,024	10,716	1,368
13	8,124	8,597	9,243	8,124	9,186	9,799	-
14	7,723	7,925	8,662	7,723	8,420	8,962	-
15	7,342	7,290	8,028	7,342	7,718	8,196	-
16	6,980	6,690	7,610	6,980	7,075	7,497	-
17	6,636	6,127	7,133	6,636	6,487	6,857	-
18	6,308	5,598	6,687	6,308	5,948	6,273	-
19	5,997	5,103	6,269	5,997	5,454	5,739	-
20	5,701	4,642	5,877	5,701	5,002	5,250	-
21	5,420	4,214	5,510	5,420	4,588	4,804	-
22	5,152	3,818	5,166	5,152	4,209	4,396	-
23	4,898	3,455	4,844	4,898	3,861	4,023	-
24	4,656	3,123	4,542	4,656	3,542	3,681	-
25	4,427	2,822	4,259	4,427	3,250	3,369	-

Source: EPA (2000).

^a Because of a lack of data, all motorcycles over 12 years old are considered to have the same emissions and travel characteristics, and therefore are aggregated together.

Table E-7: VMT Distribution by Vehicle Age and Vehicle/Fuel Type

Vehicle Age	LDGV	LDGT	HDGV	LDDV	LDDT	HDDV	MC
1	7.51%	9.41%	7.89%	7.51%	11.50%	8.27%	19.39%
2	9.52%	11.56%	13.48%	9.52%	13.07%	14.00%	21.15%
3	9.05%	10.62%	11.11%	9.05%	11.15%	11.86%	15.82%
4	8.59%	9.70%	9.85%	8.59%	9.51%	10.05%	11.82%
5	8.14%	8.80%	8.43%	8.14%	8.11%	8.52%	8.77%
6	7.68%	7.92%	7.21%	7.68%	6.92%	7.22%	6.37%

7	7.22%	7.04%	6.16%	7.22%	5.90%	6.13%	4.60%
8	6.72%	6.19%	5.27%	6.72%	5.04%	5.20%	3.31%
9	6.20%	5.36%	4.51%	6.20%	4.30%	4.41%	2.33%
10	5.64%	4.57%	3.86%	5.64%	3.67%	3.74%	1.62%
11	5.03%	3.82%	3.31%	5.03%	3.13%	3.18%	1.09%
12	4.38%	3.14%	2.83%	4.38%	2.67%	2.70%	3.73%
13	3.54%	2.52%	2.42%	3.54%	2.28%	2.29%	-
14	2.67%	1.99%	2.07%	2.67%	1.95%	1.94%	-
15	2.01%	1.54%	1.76%	2.01%	1.66%	1.65%	-
16	1.52%	1.16%	1.52%	1.52%	1.42%	1.40%	-
17	1.14%	0.87%	1.30%	1.14%	1.21%	1.19%	-
18	0.86%	0.64%	1.12%	0.86%	1.04%	1.01%	-
19	0.65%	0.50%	0.96%	0.65%	0.89%	0.86%	-
20	0.49%	0.43%	0.82%	0.49%	0.76%	0.73%	-
21	0.37%	0.37%	0.70%	0.37%	0.65%	0.62%	-
22	0.28%	0.32%	0.60%	0.28%	0.55%	0.53%	-
23	0.21%	0.27%	0.52%	0.21%	0.47%	0.45%	-
24	0.16%	0.23%	0.44%	0.16%	0.40%	0.38%	-
25	0.43%	1.04%	1.85%	0.43%	1.75%	1.65%	-
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Note: Estimated by weighting data in Table E-3 by data in Table E-4.

Table E-8: Fuel Consumption for Non-Highway Vehicles by Fuel Type (thousand gallons)

Vehicle Type/ Year	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Aircraft												
Gasoline ^a	374,216	347,126	341,582	319,449	317,307	329,319	310,797	330,285	295,345	325,913	301,893	290,679
Jet Fuel	18,280,476	17,511,325	17,281,747	17,421,016	18,270,976	17,806,704	18,746,820	18,603,881	19,063,120	19,432,004	20,355,053	19,162,649
Ships and Boats												
Diesel	1,697,600	1,693,361	1,706,144	1,546,311	1,630,093	1,518,608	1,839,335	1,801,798	1,597,011	1,863,606	1,858,210	1,996,202
Gasoline	1,300,400	1,709,700	1,316,170	873,687	896,700	1,060,394	993,671	987,193	956,232	1,098,137	1,124,269	1,095,153
Residual	1,521,437	1,486,167	2,347,065	2,758,924	2,499,868	2,994,693	2,286,350	1,011,487	723,766	2,391,248	3,289,908	897,957
Construction Equipment												
Diesel	1,581,500	1,492,000	1,514,205	1,526,043	1,531,300	1,472,827	1,645,647	1,678,482	1,749,317	1,723,597	1,899,837	2,086,388
Gasoline	318,200	287,200	272,900	245,299	272,852	280,046	283,911	300,491	234,705	177,758	191,516	506,682
Agricultural Equipment												
Diesel	3,164,200	3,144,200	3,274,811	3,077,122	3,062,436	3,093,224	3,225,029	3,206,359	2,965,006	2,805,157	3,079,664	3,350,683
Gasoline	812,800	776,200	805,500	845,320	911,996	926,732	918,085	984,450	906,941	702,700	652,256	801,552
Locomotives												
Diesel	3,324,446	3,115,970	3,212,108	3,301,981	3,585,802	3,733,096	3,820,649	3,812,793	3,859,341	3,989,428	3,960,107	3,969,985
Residual	25	7	8	4	6	6	9	3	3	4	6	3
Other^b												
Diesel	926,800	955,400	773,437	797,140	905,842	800,335	741,326	706,754	682,865	685,634	610,078	740,341
Gasoline	1,205,400	1,097,700	1,219,300	1,025,088	1,039,310	1,071,597	1,081,640	1,097,258	1,139,229	1,021,836	1,040,138	1,755,320

Sources: AAR (2001), EIA (2002b), EIA (1991 through 2002), FHWA (1996 through 2002), and other sources.

- Not applicable

^a For aircraft, this is aviation gasoline. For all other categories, this is motor gasoline.^b Other" includes snowmobiles, small gasoline powered utility equipment, heavy-duty gasoline powered utility equipment, and heavy-duty diesel powered utility equipment.

Table E-9: Control Technology Assignments for Gasoline Passenger Cars (Percent of VMT)

Model Years	Non-catalyst	Oxidation	EPA Tier 0	EPA Tier 1	LEV
1973-1974	100%	-	-	-	-
1975	20%	80%	-	-	-
1976-1977	15%	85%	-	-	-
1978-1979	10%	90%	-	-	-
1980	5%	88%	7%	-	-
1981	-	15%	85%	-	-
1982	-	14%	86%	-	-
1983	-	12%	88%	-	-
1984-1993	-	-	100%	-	-
1994	-	-	60%	40%	-
1995	-	-	20%	80%	-
1996	-	-	1%	97%	2%
1997	-	-	0.5%	96.5%	3%
1998	-	-	0.01%	87%	13%
1999	-	-	0.01%	67%	33%
2000	-	-	-	44%	56%
2001	-	-	-	3%	97%

Sources: EPA (1998), EPA (2002a), and EPA (2002b)

Detailed descriptions of emissions control technologies are provided at the end of this annex.

- Not applicable

Table E-10: Control Technology Assignments for Gasoline Light-Duty Trucks (Percent of VMT)

Model Years	Non-catalyst	Oxidation	EPA Tier 0	EPA Tier 1	LEV
1973-1974	100%	-	-	-	-
1975	30%	70%	-	-	-
1976	20%	80%	-	-	-
1977-1978	25%	75%	-	-	-
1979-1980	20%	80%	-	-	-
1981	-	95%	5%	-	-
1982	-	90%	10%	-	-
1983	-	80%	20%	-	-
1984	-	70%	30%	-	-
1985	-	60%	40%	-	-
1986	-	50%	50%	-	-
1987-1993	-	5%	95%	-	-
1994	-	-	60%	40%	-
1995	-	-	20%	80%	-
1996	-	-	-	100%	-
1997	-	-	-	100%	-
1998	-	-	-	80%	20%
1999	-	-	-	57%	43%
2000	-	-	-	65%	35%
2001	-	-	-	1%	99%

Sources: EPA (1998), EPA (2002a), and EPA (2002b)

Detailed descriptions of emissions control technologies are provided at the end of this annex.

- Not applicable.

Table E-11: Control Technology Assignments for Gasoline Heavy-Duty Vehicles (Percent of VMT)

Model Years	Uncontrolled	Non-catalyst	Oxidation	EPA Tier 0	EPA Tier 1	LEV
≤1981	100%	-	-	-	-	-

1982-1984	95%	-	5%	-	-	-
1985-1986	-	95%	5%	-	-	-
1987	-	70%	15%	15%	-	-
1988-1989	-	60%	25%	15%	-	-
1990-1995	-	45%	30%	25%	-	-
1996	-	-	25%	10%	65%	-
1997	-	-	10%	5%	85%	-
1998	-	-	-	-	96%	4%
1999	-	-	-	-	78%	22%
2000	-	-	-	-	54%	46%
2001	-	-	-	-	64%	36%

Sources: EPA (1998), EPA (2002a), and EPA (2002b)

Detailed descriptions of emissions control technologies are provided at the end of this annex.

- Not applicable

Table E-12: Control Technology Assignments for Diesel Highway and Motorcycle VMT

Vehicle Type/Control Technology	Model Years
Diesel Passenger Cars and Light-Duty Trucks	
Uncontrolled	1966-1982
Moderate control	1983-1995
Advanced control	1996-2001
Heavy-Duty Diesel Vehicles	
Uncontrolled	1966-1972
Moderate control	1983-1995
Advanced control	1996-2001
Motorcycles	
Uncontrolled	1966-1995
Non-catalyst controls	1996-2001

Source: EPA (1998)

Detailed descriptions of emissions control technologies are provided at the end of this annex.

Table E-13: Emission Factors for CH₄ and N₂O for Highway Vehicles

Vehicle Type/Control Technology	N ₂ O (g/mi)	CH ₄ (g/mi)	N ₂ O (g/km)	CH ₄ (g/km)
Gasoline Passenger Cars				
Low Emission Vehicles	0.0283	0.0402	0.0176	0.025
EPA Tier 1 ^a	0.0463	0.0483	0.0288	0.030
EPA Tier 0 ^a	0.0816	0.0644	0.0507	0.040
Oxidation Catalyst	0.0518	0.1126	0.0322	0.070
Non-Catalyst	0.0166	0.1931	0.0103	0.120
Uncontrolled	0.0166	0.2173	0.0103	0.135
Gasoline Light-Duty Trucks				
Low Emission Vehicles	0.0354	0.0483	0.0220	0.030
EPA Tier 1 ^a	0.0581	0.0563	0.0361	0.035
EPA Tier 0 ^a	0.1022	0.1126	0.0635	0.070
Oxidation Catalyst	0.0649	0.1448	0.0403	0.090
Non-Catalyst	0.0208	0.2253	0.0129	0.140
Uncontrolled	0.0208	0.2173	0.0129	0.135
Gasoline Heavy-Duty Vehicles				
Low Emission Vehicles	0.1133	0.0708	0.0704	0.044
EPA Tier 1 ^a	0.1394	0.0966	0.0866	0.060
EPA Tier 0 ^a	0.1746	0.1207	0.1085	0.075
Oxidation Catalyst ^b	0.1109	0.1448	0.0689	0.090
Non-Catalyst Control	0.0354	0.2012	0.0220	0.125

Uncontrolled	0.0354	0.4345	0.0220	0.270
Diesel Passenger Cars				
Advanced	0.0161	0.0161	0.0100	0.010
Moderate	0.0161	0.0161	0.0100	0.010
Uncontrolled	0.0161	0.0161	0.0100	0.010
Diesel Light-Duty Trucks				
Advanced	0.0322	0.0161	0.0200	0.010
Moderate	0.0322	0.0161	0.0200	0.010
Uncontrolled	0.0322	0.0161	0.0200	0.010
Diesel Heavy-Duty Vehicles				
Advanced	0.0483	0.0644	0.0300	0.040
Moderate	0.0483	0.0805	0.0300	0.050
Uncontrolled	0.0483	0.0966	0.0300	0.060
Motorcycles				
Non-Catalyst Control	0.0071	0.2092	0.0044	0.130
Uncontrolled	0.0071	0.4184	0.0044	0.260

Sources: IPCC/UNEP/OECD/IEA (1997), EPA (1998)

^a The categories “EPA Tier 0” and “EPA Tier 1” were substituted for the early three-way catalyst and advanced three-way catalyst categories, respectively, as defined in the Revised 1996 IPCC Guidelines. Detailed descriptions of emissions control technologies are provided at the end of this annex.

^b The methane emission factor was assumed based on the oxidation catalyst value for gasoline light-duty trucks.

Table E-14: Emission Factors for CH₄ and N₂O for Alternative Fuel/Vehicle Technology Highway Vehicles

Vehicle Type/Control Technology	N₂O (g/mi)	CH₄ (g/mi)	N₂O (g/km)	CH₄ (g/km)
Light-duty Vehicles				
Methanol	0.063	0.014	0.039	0.009
CNG	0.113	0.914	0.070	0.568
LPG	0.152	0.609	0.094	0.378
Ethanol	0.076	0.043	0.047	0.027
Heavy-duty Vehicles				
Methanol	0.217	0.646	0.135	0.401
CNG	0.297	9.629	0.185	5.983
LNG	0.440	6.857	0.274	4.261
LPG	0.150	0.108	0.093	0.067
Ethanol	0.307	1.975	0.191	1.227
Buses				
Methanol	0.217	0.646	0.135	0.401
CNG	0.162	12.416	0.101	7.715
Ethanol	0.364	2.079	0.226	1.292

Source: Developed from Wang (1999), Lipman and Delucchi (2002), CRC (1997), Brasil and McMahon (1999), Norbeck, et al (1998), and DOE (2002a).

Table E-15: Emission Factors for CH₄ and N₂O Emissions from Non-Highway Mobile Combustion (g gas/kg fuel)

Vehicle Type/Fuel Type	N₂O	CH₄
Ships and Boats		
Residual	0.08	0.230
Distillate	0.08	0.230
Gasoline	0.08	0.230
Locomotives		
Residual	0.08	0.250
Diesel	0.08	0.250
Agricultural Equipment		

Gas	0.08	0.450
Diesel	0.08	0.450
Construction		
Gas	0.08	0.180
Diesel	0.08	0.180
Other Non-Highway		
Gas Snowmobile	0.08	0.180
Gas Small Utility	0.08	0.180
Gas HD Utility	0.08	0.180
Diesel HD Utility	0.08	0.180
Aircraft		
Jet Fuel	0.10	0.087
Aviation Gasoline	0.04	2.640

Source: IPCC/UNEP/OECD/IEA (1997).

Table E-16: CH₄ Emissions from Mobile Combustion (Tg CO₂ Eq.)

Fuel Type/Vehicle Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Gasoline Highway	4.3	4.2	4.2	4.2	4.2	4.1	4.0	3.9	3.8	3.7	3.6	3.4
Passenger Cars	2.4	2.2	2.2	2.1	2.1	2.0	2.0	2.0	2.0	1.9	1.9	1.8
Light-Duty Trucks	1.6	1.7	1.8	1.9	1.9	1.8	1.8	1.7	1.6	1.6	1.5	1.5
Heavy-Duty Vehicles	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Motorcycles	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	+
Diesel Highway	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Passenger Cars	+	+	+	+	+	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+	+	+	+	+	+
Heavy-Duty Vehicles	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Alternative Fuel Highway	+	+	+	+	+	+	0.1	0.1	0.1	0.1	0.1	0.1
Non-Highway	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.4	0.4	0.5	0.5	0.5
Ships and Boats	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Locomotives	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Agricultural Equipment	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Construction Equipment	+	+	+	+	+	+	+	+	+	+	+	+
Aircraft	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.2	0.2	0.1
Other*	+	+	+	+	+	+	+	+	+	+	+	+
Total	5.0	4.9	5.0	4.9	4.9	4.9	4.8	4.7	4.6	4.5	4.4	4.3

+ Does not exceed 0.05 Tg CO₂ Eq.

Note: Totals may not sum due to independent rounding.

* "Other" includes snowmobiles, small gasoline powered utility equipment, heavy-duty gasoline powered utility equipment, and heavy-duty diesel powered utility equipment.

Table E-17: N₂O Emissions from Mobile Combustion (Tg CO₂ Eq.)

Fuel Type/Vehicle Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Gasoline Highway	45.6	48.0	51.1	53.4	54.8	55.2	54.9	54.4	53.7	52.5	51.0	48.4
Passenger Cars	30.9	30.7	31.8	32.5	33.3	33.4	33.0	32.5	32.2	31.2	30.2	28.6
Light-Duty Trucks	13.9	16.4	18.4	20.0	20.6	20.9	20.8	20.9	20.4	20.2	19.6	18.6
Heavy-Duty Vehicles	0.7	0.8	0.8	0.9	0.9	1.0	1.0	1.1	1.1	1.1	1.1	1.1
Motorcycles	+	+	+	+	+	+	+	+	+	+	+	+
Diesel Highway	2.0	2.1	2.2	2.3	2.4	2.6	2.6	2.8	2.9	3.0	3.0	3.1
Passenger Cars	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	+	+	+
Light-Duty Trucks	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3

Heavy-Duty Vehicles	1.8	1.8	1.9	2.0	2.2	2.3	2.4	2.5	2.6	2.7	2.7	2.8
Alternative Fuel Highway	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2
Non-Highway	2.9	2.9	2.9	2.9	3.0	3.0	3.1	2.9	2.9	3.1	3.3	3.1
Ships and Boats	0.4	0.4	0.4	0.4	0.4	0.5	0.4	0.3	0.3	0.4	0.5	0.3
Locomotives	0.3	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Agricultural Equipment	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Construction Equipment	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.1	0.2	0.2
Aircraft	1.7	1.6	1.6	1.6	1.7	1.7	1.8	1.7	1.8	1.8	1.9	1.8
Other*	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2
Total	50.6	53.0	56.2	58.6	60.4	60.9	60.7	60.3	59.7	58.8	57.5	54.8

+ Does not exceed 0.05 Tg CO₂ Eq.

Note: Totals may not sum due to independent rounding.

* "Other" includes snowmobiles, small gasoline powered utility equipment, heavy-duty gasoline powered utility equipment, and heavy-duty diesel powered utility equipment.

Table E-18: NO_x Emissions from Mobile Combustion, 1990-2001 (Gg)

Fuel Type/Vehicle Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Gasoline Highway	5,746	5,508	5,271	5,034	4,797	4,559	4,322	4,268	4,090	3,913	3,812	3,942
Passenger Cars	3,847	3,628	3,409	3,190	2,971	2,752	2,533	2,447	2,316	2,152	2,084	2,150
Light-Duty Trucks	1,364	1,356	1,349	1,341	1,333	1,325	1,318	1,334	1,294	1,264	1,303	1,363
Heavy-Duty Vehicles	515	505	496	487	478	469	459	475	467	484	411	414
Motorcycles	20	19	17	16	15	14	13	13	13	13	13	14
Diesel Highway	2,956	3,064	3,171	3,278	3,386	3,493	3,600	3,708	3,729	3,660	3,803	3,542
Passenger Cars	39	35	31	27	23	19	15	13	11	10	7	6
Light-Duty Trucks	20	19	17	16	14	12	11	10	9	8	6	6
Heavy-Duty Vehicles	2,897	3,010	3,123	3,236	3,349	3,462	3,575	3,685	3,709	3,643	3,791	3,530
Alternative Fuel Highway	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE
Non-Highway	3,432	3,492	3,552	3,612	3,672	3,732	3,791	3,792	3,772	4,009	3,780	3,770
Ships and Boats	953	962	971	980	990	999	1,008	963	919	885	966	971
Locomotives	857	873	888	904	920	935	951	962	973	984	908	907
Agricultural Equipment	437	445	453	461	470	478	486	487	487	538	484	480
Construction Equipment	641	652	663	675	686	697	708	708	706	827	697	690
Aircraft ^b	63	64	65	65	66	67	67	75	83	91	80	73
Other ^c	480	496	511	526	541	556	572	597	604	683	645	650
Total	12,134	12,064	11,994	11,924	11,854	11,784	11,714	11,768	11,592	11,582	11,395	11,254

NE Not Estimated

^a Aircraft estimates include only emissions related to LTO cycles, and therefore do not include cruise altitude emissions.

^b "Other" includes gasoline powered recreational, industrial, lawn and garden, light commercial, logging, airport service, other equipment; and diesel powered recreational, industrial, lawn and garden, light construction, airport service.

Note: Totals may not sum due to independent rounding.

Table E-19: CO Emissions from Mobile Combustion, 1990-2001 (Gg)

Fuel Type/Vehicle Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Gasoline Highway	98,328	93,597	88,866	84,135	79,403	74,672	69,941	67,509	65,246	60,727	60,657	66,857
Passenger Cars	60,757	57,019	53,281	49,542	45,804	42,065	38,327	36,825	35,686	32,661	32,867	37,250
Light-Duty Trucks	29,237	28,799	28,361	27,923	27,486	27,048	26,610	25,748	24,754	23,159	24,532	26,611
Heavy-Duty Vehicles	8,093	7,555	7,017	6,480	5,942	5,404	4,867	4,787	4,642	4,744	3,104	2,842
Motorcycles	240	223	206	189	172	155	138	150	163	163	154	155
Diesel Highway	1,696	1,642	1,587	1,533	1,479	1,424	1,370	1,301	1,202	1,113	1,088	1,025
Passenger Cars	35	31	28	25	21	18	15	13	10	10	7	7
Light-Duty Trucks	22	21	20	18	17	16	14	13	12	9	6	6
Heavy-Duty Vehicles	1,639	1,589	1,539	1,490	1,440	1,391	1,341	1,276	1,179	1,094	1,075	1,011
Alternative Fuel Highway	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE
Non-Highway	19,459	19,899	20,339	20,778	21,218	21,658	22,098	21,474	21,493	22,733	21,935	22,387

Ships and Boats	1,679	1,724	1,770	1,815	1,861	1,906	1,951	1,948	1,943	2,280	1,945	1,952
Locomotives	85	86	88	90	91	93	94	89	83	105	90	90
Agricultural Equipment	582	591	600	610	619	628	638	636	633	677	626	621
Construction Equipment	1,090	1,098	1,107	1,115	1,123	1,132	1,140	1,098	1,081	1,154	1,047	1,041
Aircraft ^b	217	218	220	221	222	224	225	250	274	307	245	233
Other ^c	15,807	16,181	16,554	16,928	17,302	17,676	18,049	17,453	17,478	18,210	17,981	18,449
Total	119,482	115,137	110,791	106,446	102,100	97,755	93,409	90,284	87,940	84,574	83,680	90,268

NE Not Estimated

^a Aircraft estimates include only emissions related to LTO cycles, and therefore do not include cruise altitude emissions.

^b “Other” includes gasoline powered recreational, industrial, lawn and garden, light commercial, logging, airport service, other equipment; and diesel powered recreational, industrial, lawn and garden, light construction, airport service.

Note: Totals may not sum due to independent rounding.

Table E-20: NMVOCs Emissions from Mobile Combustion, 1990-2001 (Gg)

Fuel Type/Vehicle Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Gasoline Highway	8,110	7,652	7,194	6,735	6,277	5,819	5,360	5,167	5,067	4,865	4,615	4,217
Passenger Cars	5,120	4,774	4,429	4,084	3,739	3,394	3,049	2,928	2,895	2,777	2,610	2,355
Light-Duty Trucks	2,374	2,303	2,232	2,161	2,090	2,019	1,947	1,882	1,812	1,713	1,750	1,638
Heavy-Duty Vehicles	575	536	498	459	420	382	343	336	335	347	232	203
Motorcycles	42	38	35	31	28	24	21	22	25	27	23	22
Diesel Highway	406	386	365	345	324	304	283	263	249	227	216	204
Passenger Cars	16	15	13	12	10	8	7	6	5	5	3	3
Light-Duty Trucks	14	13	12	11	10	9	9	8	7	6	4	4
Heavy-Duty Vehicles	377	358	340	322	304	286	268	249	237	216	209	198
Alternative Fuel Highway	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE
Non-Highway	2,416	2,457	2,498	2,540	2,581	2,622	2,663	2,498	2,427	2,567	2,398	2,379
Ships and Boats	608	634	660	687	713	739	765	766	763	811	744	730
Locomotives	33	34	35	35	36	36	37	35	33	40	35	35
Agricultural Equipment	85	85	85	86	86	86	86	83	81	86	76	72
Construction Equipment	149	150	150	151	152	152	153	142	137	149	130	125
Aircraft ^b	28	28	28	28	28	28	28	32	35	40	24	19
Other ^c	1,513	1,527	1,540	1,553	1,567	1,580	1,593	1,441	1,378	1,442	1,390	1,397
Total	10,933	10,495	10,058	9,620	9,182	8,744	8,306	7,928	7,742	7,658	7,230	6,800

NE Not Estimated

^a Aircraft estimates include only emissions related to LTO cycles, and therefore do not include cruise altitude emissions.

^b “Other” includes gasoline powered recreational, industrial, lawn and garden, light commercial, logging, airport service, other equipment; and diesel powered recreational, industrial, lawn and garden, light construction, airport service.

Note: Totals may not sum due to independent rounding.

Definitions of Emission Control Technologies and Standards

The N₂O and CH₄ emission factors used depend on the emission standards in place and the corresponding level of control technology for each vehicle type. Table E-9 through Table E-12 show the years in which these technologies or standards were in place and the penetration level for each vehicle type. These categories are defined below.

Uncontrolled

Vehicles manufactured prior to the implementation of pollution control technologies are designated as uncontrolled. Gasoline light-duty cars and trucks (pre-1973), gasoline heavy-duty vehicles (pre-1984), diesel vehicles (pre-1983), and motorcycles (pre-1996) are assumed to not have significant control technologies in place.

Gasoline Emission Controls

Below are the control technologies and emissions standards applicable to gasoline vehicles.

Non-catalyst

These emission controls were common in gasoline passenger cars and light-duty gasoline trucks during model years (1973-1974) but phased out thereafter, in heavy-duty gasoline vehicles beginning in the mid-1980s, and in motorcycles beginning in 1996. This technology reduces hydrocarbon (HC) and carbon monoxide (CO) emissions through adjustments to ignition timing and air-fuel ratio, air injection into the exhaust manifold, and exhaust gas recirculation (EGR) valves, which also helps meet vehicle NO_x standards (EPA 1994b).

Oxidation catalyst

This control technology designation represents the introduction of the catalytic converter, and was the most common technology in gasoline passenger cars and light-duty gasoline trucks made from 1975 to 1980 (cars) and 1975 to 1985 (trucks). This technology was also used in some heavy-duty gasoline vehicles between 1982 and the present. The two-way catalytic converter oxidizes HC and CO, significantly reducing emissions over 80 percent beyond non-catalyst-system capacity (EPA 1993). One reason unleaded gasoline was introduced in 1975 was due to the fact that oxidation catalysts cannot function properly with leaded gasoline (EPA 1994a).

EPA Tier 0

This emission standard from the Clean Air Act was met through the implementation of early “three-way” catalysts, therefore this technology was used in gasoline passenger cars and light-duty gasoline trucks sold beginning in the early 1980s, and remained common until 1994. This more sophisticated emission control system improves the efficiency of the catalyst by converting CO and HC to CO₂ and H₂O, reducing NO_x to nitrogen and oxygen, and using an on-board diagnostic computer and oxygen sensor (EPA 1994a). In addition, this type of catalyst includes a carburetor with electronic “trim” (also known as a “closed-loop carburetor”) IPCC/UNEP/OECD/IEA (1997).¹ New cars with three-way catalysts met the Clean Air Act’s amended standards (enacted in 1977) of reducing HC to 0.41 g/mile by 1980, CO to 3.4 g/mile by 1981 and NO_x to 1.0 g/mile by 1981.

EPA Tier 1

This emission standard created through the 1990 amendments to the Clean Air Act called for a 40 percent reduction from the 1981 standard. This was met through the use of more advanced 3-way catalysts, and applied to light-duty gasoline vehicles beginning in 1994. This catalyst includes electronically controlled fuel injections and ignition timing, EGR, and air injection. The EPA Tier 1 standards reduce NO_x emissions to 0.6 g/mile for cars and 0.6 to 1.53 g/mile for trucks (EPA 1999).

Low Emission Vehicles (LEV)

This emission standard provides the highest mobile emission control in effect currently at the national level. Applied to light-duty gasoline passenger cars and trucks beginning in small numbers in the mid-1990’s, LEV includes multi-port fuel injection with adaptive learning, an advanced computer diagnostics systems and heated catalysts with secondary air injection IPCC/UNEP/OECD/IEA (1997). LEVs as defined here include transitional low-emission vehicles (TLEVs), low emission vehicles, ultra-low emission vehicles (ULEVs) and super ultra-low

¹ Electronic trim control systems change the ratio of fuel to air in the engine.

emission vehicles (SULEVs). In this analysis, all categories of LEVs are treated the same due to the fact that there are virtually no CH₄ or N₂O emission factor data for LEVs to distinguish among the different types of vehicles. Zero emission vehicles (ZEVs) are incorporated into the alternative fuel and advanced technology vehicle assessments.

Diesel Emission Controls

Below are the two levels of emissions control for diesel vehicles.

Moderate control

Improved injection timing technology and combustion system design for light- and heavy-duty diesel vehicles (generally in place in model years 1983 to 1995) are considered moderate control technologies (IPCC/UNEP/OECD/IEA 1997). These controls were implemented to meet emission standards for diesel trucks and buses adopted by the EPA in 1985 to be met in 1991 and 1994.

Advanced control

EGR and modern electronic control of the fuel injection system are designated as advanced control technologies. These technologies provide diesel vehicles with the current highest level of emission control, and were used in model years beginning in 1996.

Supplemental Information on Transportation-Related GHG Emissions

Although not required in greenhouse gas inventory reporting, IPCC allows presentation of further details and data. As the transportation end-use sector is a large consumer of fossil fuels in the United States, a more detailed disaggregation of transportation activities contributing to emissions is provided. Based on information and data sources that are already available, the supplemental data presented below are an effort to present this more detailed disaggregation.

Transportation-related sources include highway vehicles, aircraft, boats and ships, locomotives, and other transportation and mobile sources, as described in this annex. Transportation is typically defined as including pipelines (which are stationary), but not construction equipment, agricultural equipment, and certain other mobile sources that do not provide transportation *per se*². Conversely, the term “mobile sources” does not include pipeline transportation, but does include construction equipment, agricultural equipment, and certain other mobile sources. Highway, rail, aviation, and waterborne vehicles all fall under both terms. This annex primarily uses the term transportation to include all transportation-related and mobile sources in this one category.

The estimates in Table E-21, Table E-22, and Table E-23 and illustrated in Figure E-1 were prepared by re-aggregating the estimates presented in Tables 1-14 and 2-7, Chapter 3, and Annex K so that each transportation mode and/or vehicle type is presented with its total greenhouse gas emissions, rather than its emissions disaggregated by fuel type or greenhouse gas. For the cases of Table E-1, Table E-23 and Figure E-1, DOE (1993 through 2002) and FHWA (1996 through 2002) were also used to allocate rail and heavy duty highway vehicle (trucks and buses) between freight and passenger categories. Otherwise, these tables and figures are dependent on the methodologies presented in Annex A (for CO₂), Chapter 3 and Annex K (for HFCs), and earlier in this Annex (for CH₄ and N₂O).

² Transportation is frequently defined in official surveys, etc. as the movement of persons or goods from one address to another address, and thus excludes many of the above-listed and other mobile sources.

The methodologies used to aggregate all the transportation greenhouse gas emissions data in Table E-21 are summarized here. The HFC emissions, which come from the coolants for air conditioning or refrigeration used in vehicles, are estimated, as indicated in Annex K, by calculating the number and types of coolant equipment in use and estimating the emissions from leakage during the equipment life and disposal. The CH₄ and N₂O emissions are estimated, as indicated in the first part of this annex, by compiling the activity-level data and estimating emissions based on emission factors for each vehicle type. For non-road vehicles, the activity data is based on fuel consumption. However, for highway vehicles, an accurate estimate of methane and nitrous oxide emissions is dependent not just on the fuel consumption, but also on the type of vehicle and its associated criteria pollutant control technologies. Therefore, the methodology involves obtaining Vehicle Miles Traveled (VMT) data, assigning that activity by both fuel type and vehicle type, using the age distribution (and associated control technologies based on vehicle age) for the U.S. fleet. Then very specific emission factors can be used to estimate CH₄ and N₂O emissions based on the allocated activity level data. The CO₂ emissions are first estimated, as indicated in Annex A, by calculating fuel consumption for the transportation sector by fuel type and vehicle type, and estimating CO₂ emissions based on the carbon content of the fuel (see Table A-16 and Table A-17). However, identifying CO₂ emissions based on fuel type divides natural transportation categories such as passenger cars or buses into multiple line items (by listing emissions from gasoline separately from diesel or natural gas). The tables in this annex reorganize the CO₂ data according to the different modes of passenger vehicles, freight, and transit, and provide more detailed information on the activities that comprise these emissions. Table E-21 aggregates all greenhouse gases from transportation activities by mode.

Public Passenger Transportation

This section presents greenhouse gas emission estimates for “public passenger transportation”, using a broad definition that includes all passenger vehicles available to the public for a fare or ticket price (or similar free services, such as many school buses or local shuttle buses). This category thus includes buses, passenger rail, and commercial aviation, as shown in Figure E-3. This category was developed to complement the previous two categories, passenger cars/trucks and freight, with the other main segment of the sector, public passenger transportation.

Uncertainty

Much of the data presented in this annex, such as the estimates from CO₂ emissions from transportation activities, are considered, in the aggregate, to be fairly accurate. Several of the tables in this annex represent the reorganization of data presented elsewhere in the Inventory, and this reorganization may introduce additional uncertainties in the disaggregated data. Minor uncertainty exists in the estimates of freight and public passenger transport emissions, where additional data from DOE (1993 through 2002) was used to allocate the passenger/freight split of rail emissions and to disaggregate buses. The data presented regarding daily travel, long-distance travel, and commodity flows all present the direct estimates made by their respective surveys. As the original surveys relied on survey and sampling techniques and attempted to collect detailed, disaggregate data, some uncertainty can be associated with their original estimates.

Table E-21: U.S. Greenhouse Gas Emissions from Transportation and Mobile Sources (Tg CO₂ Eq.)

Mode / Vehicle Type / Fuel Type	1990	1996	1997	1998	1999	2000	2001	Contribution to U.S. Transportation Total	Change from 1990-2001
Highway Vehicles	1,172.0	1,318.8	1,340.7	1,375.9	1,419.7	1,435.5	1,456.3	77.9%	24.3%
Passenger Cars	633.9	629.6	627.5	642.4	652.0	654.0	663.6	35.5%	4.7%
Gasoline	627.4	624.6	622.6	637.7	647.3	649.6	659.3	35.3%	5.1%
Diesel	6.4	4.8	4.7	4.5	4.4	4.2	4.0	0.2%	-37.9%
AFVs	0.1	0.2	0.2	0.2	0.2	0.3	0.3	0.0%	146.0%
Light-Duty Trucks	322.4	429.8	442.4	450.3	468.4	472.0	480.7	25.7%	49.1%
Gasoline	312.8	416.9	428.6	436.2	453.4	456.8	465.3	24.9%	48.8%
Diesel	9.1	12.4	13.4	13.6	14.7	14.8	15.0	0.8%	66.0%
AFVs	0.5	0.5	0.4	0.4	0.3	0.3	0.3	0.0%	-46.8%
Medium/Heavy-Duty Trucks	206.5	249.3	260.5	272.5	287.4	297.8	301.3	16.1%	45.9%
Gasoline	40.6	37.2	35.9	35.8	35.0	34.6	33.6	1.8%	-17.4%
Diesel	165.1	211.6	224.2	236.1	252.0	262.7	267.3	14.3%	62.0%
AFVs	0.8	0.5	0.4	0.6	0.5	0.5	0.5	0.0%	-40.9%
Buses	7.5	8.3	8.5	8.8	9.9	9.8	9.0	0.5%	20.6%
Gasoline	1.6	0.9	0.7	0.7	0.7	0.6	0.5	0.0%	-71.8%
Diesel	5.8	7.3	7.6	7.9	9.0	8.7	8.1	0.4%	39.3%
AFVs	0.0	0.1	0.2	0.3	0.3	0.5	0.4	0.0%	n.a.
Motorcycles	1.8	1.8	1.8	1.8	1.9	1.9	1.7	0.1%	-3.7%
Gasoline	1.8	1.8	1.8	1.8	1.9	1.9	1.7	0.1%	-3.7%
Aircraft	178.8	182.1	180.9	185.0	188.7	197.4	185.9	9.9%	4.0%
General Aviation Aircraft	9.4	8.3	8.8	10.1	11.8	11.9	11.7	0.6%	25.1%
Jet Fuel	6.3	5.8	6.1	7.7	9.2	9.5	9.3	0.5%	48.2%
Aviation Gasoline	3.1	2.6	2.7	2.4	2.7	2.5	2.4	0.1%	-22.3%
Commercial Aircraft	120.0	126.8	131.3	133.4	139.2	143.0	133.5	7.1%	11.3%
Jet Fuel	120.0	126.8	131.3	133.4	139.2	143.0	133.5	7.1%	11.3%
Military Aircraft	34.8	23.1	21.0	21.5	20.6	21.0	22.8	1.2%	-34.3%
Jet Fuel	34.8	23.1	21.0	21.5	20.6	21.0	22.8	1.2%	-34.3%
Other Aircraft	14.6	23.9	19.7	19.9	17.0	21.4	17.8	1.0%	22.0%
Jet Fuel	14.6	23.9	19.7	19.9	17.0	21.4	17.8	1.0%	22.0%
Boats and Ships	49.0	48.6	34.0	27.7	39.1	60.3	58.7	3.1%	19.6%
Gasoline	11.2	8.5	8.4	8.1	9.3	9.6	9.5	0.5%	-15.5%
Distillate Fuel	14.0	15.0	14.6	13.1	15.6	15.5	16.8	0.9%	20.0%
Residual Fuel	23.8	25.1	11.0	6.5	14.2	35.2	32.4	1.7%	35.9%
Locomotives	28.4	32.2	32.0	32.7	34.4	34.2	34.6	1.9%	22.0%
Distillate Fuel	27.8	31.6	31.3	32.1	33.8	33.4	33.9	1.8%	21.9%
Electricity	0.6	0.6	0.7	0.6	0.7	0.7	0.8	0.0%	28.2%
Pipelines	38.3	41.1	43.3	37.3	37.8	37.7	36.3	1.9%	-5.4%
Natural Gas	35.9	38.7	40.9	34.9	35.3	35.0	33.5	1.8%	-6.7%
Electricity	2.4	2.4	2.4	2.5	2.5	2.7	2.8	0.1%	14.6%
Agricultural Equipment	33.4	34.5	34.6	32.3	29.7	31.5	35.5	1.9%	6.3%
Gasoline	7.0	7.9	8.4	7.7	5.9	5.6	6.9	0.4%	-1.1%
Diesel	26.4	26.6	26.3	24.7	23.7	26.0	28.6	1.5%	8.2%
Construction Equipment	16.0	16.0	16.3	16.6	16.1	17.7	22.2	1.2%	39.0%
Gasoline	2.7	2.4	2.5	2.0	1.5	1.6	4.4	0.2%	59.8%

Diesel	13.2	13.6	13.8	14.6	14.6	16.0	17.8	1.0%	34.7%
Lubricants	11.7	10.9	11.5	12.0	12.1	12.0	12.1	0.6%	3.0%
Mobile Air Conditioners	0.0	9.8	12.9	15.7	18.2	20.4	22.5	1.2%	NA
Refrigerated Transport	0.0	1.9	2.5	3.2	3.8	4.4	4.9	0.3%	NA
Other*	0.2	0.1	0.1	0.1	0.1	0.1	0.2	0.0%	17.1%
Total	1,527.8	1,696.1	1,708.8	1,738.5	1,799.8	1,851.1	1,869.0	100.0%	22.3%

* "Other" includes snowmobiles, small gasoline-powered utility equipment, heavy-duty gasoline-powered utility equipment, and heavy-duty diesel-powered utility equipment.

NA: Not Applicable

Source: Derived from Table 1-14, Table 2-7, Table E-16, and Table E-17. Greenhouse gas estimates for each mode were assigned to fuel types using fuel consumption data.

Note: For fuel types other than jet fuel, fuel consumption data by vehicle type and transportation mode were used to allocate emissions by fuel type calculated for the transportation end-use sector. The difference between total U.S. jet fuel consumption (as reported by EIA) and civilian air carrier consumption for both domestic and international flights (as reported by DOT and BEA) plus military jet fuel consumption is reported as "other" under the jet fuel category in Table 2-7, and includes such fuel uses as blending with heating oils and fuel used for chartered aircraft flights.

Figure E-1: 2001 Domestic Greenhouse Gas Emissions by Vehicle Type (Tg CO₂ Eq.)

*Other includes non-highway sources not in other categories, such as construction and agricultural equipment, pipelines, lubricants, mobile air conditioners, and refrigerated transport but does not include bunkers.

Source: Table E-21.

Table E-22: Greenhouse Gas Emissions from Domestic Freight Transportation (Tg CO₂ Eq.)

By Mode	1990	1996	1997	1998	1999	2000	2001	% Change 1990-2001
Trucking	206.5	249.3	260.5	272.5	287.4	297.8	301.3	46%
Rail	26.4	30.2	29.9	30.7	32.3	32.0	32.4	22%
Refrigerated Transport	0.0	1.9	2.5	3.2	3.8	4.4	4.9	NA
Waterborne	37.8	40.1	25.6	19.6	29.8	50.7	49.2	30%
Pipeline	38.3	41.1	43.3	37.3	37.8	37.7	36.3	-5%
Total	309.1	362.7	361.9	363.3	391.1	422.6	424.0	37%

NA Signifies data not applicable, as there were no HFC emissions allocated to the transport sector in 1990, and thus a growth rate cannot be calculated.

Note: Data from DOE (1993 through 2002) was used to allocate the passenger/freight split of rail emissions.

Figure E-2: Greenhouse Gas Emissions from Domestic Freight Transportation by Mode (Tg CO₂ Eq.)

Table E-23: Greenhouse Gas Emissions from Public Passenger Transportation (Tg CO₂ Eq.)

Vehicle Type / Fuel Type	1990	1996	1997	1998	1999	2000	2001
Passenger Rail	2.0	1.9	2.1	2.1	2.1	2.2	2.3
Electricity	0.6	0.6	0.7	0.6	0.7	0.7	0.8
Diesel	1.4	1.3	1.4	1.4	1.5	1.5	1.5
Buses	7.5	8.3	8.5	8.8	9.9	9.8	9.0
Gasoline	1.6	0.9	0.7	0.7	0.7	0.6	0.5
Diesel	5.8	7.3	7.6	7.9	9.0	8.7	8.1

AFVs	0.0		0.1	0.2	0.3	0.3	0.5	0.4
Commercial Aviation	120.0		126.8	131.3	133.4	139.2	143.0	133.5
Jet Fuel	120.0		126.8	131.3	133.4	139.2	143.0	133.5
Total	128.1		135.7	140.5	142.9	149.8	153.5	143.3

Source: Table 1-14.

Note: Data from DOE (1993 through 2002) was used to disaggregate emissions from rail and buses.

Figure E-3: Total Greenhouse Gas Emissions from Public Passenger Transportation by Vehicle Type (Tg CO₂ Eq.)

Figure E-1: 2001 Domestic GHG Emissions by Vehicle Type (Tg CO₂ Eq.)

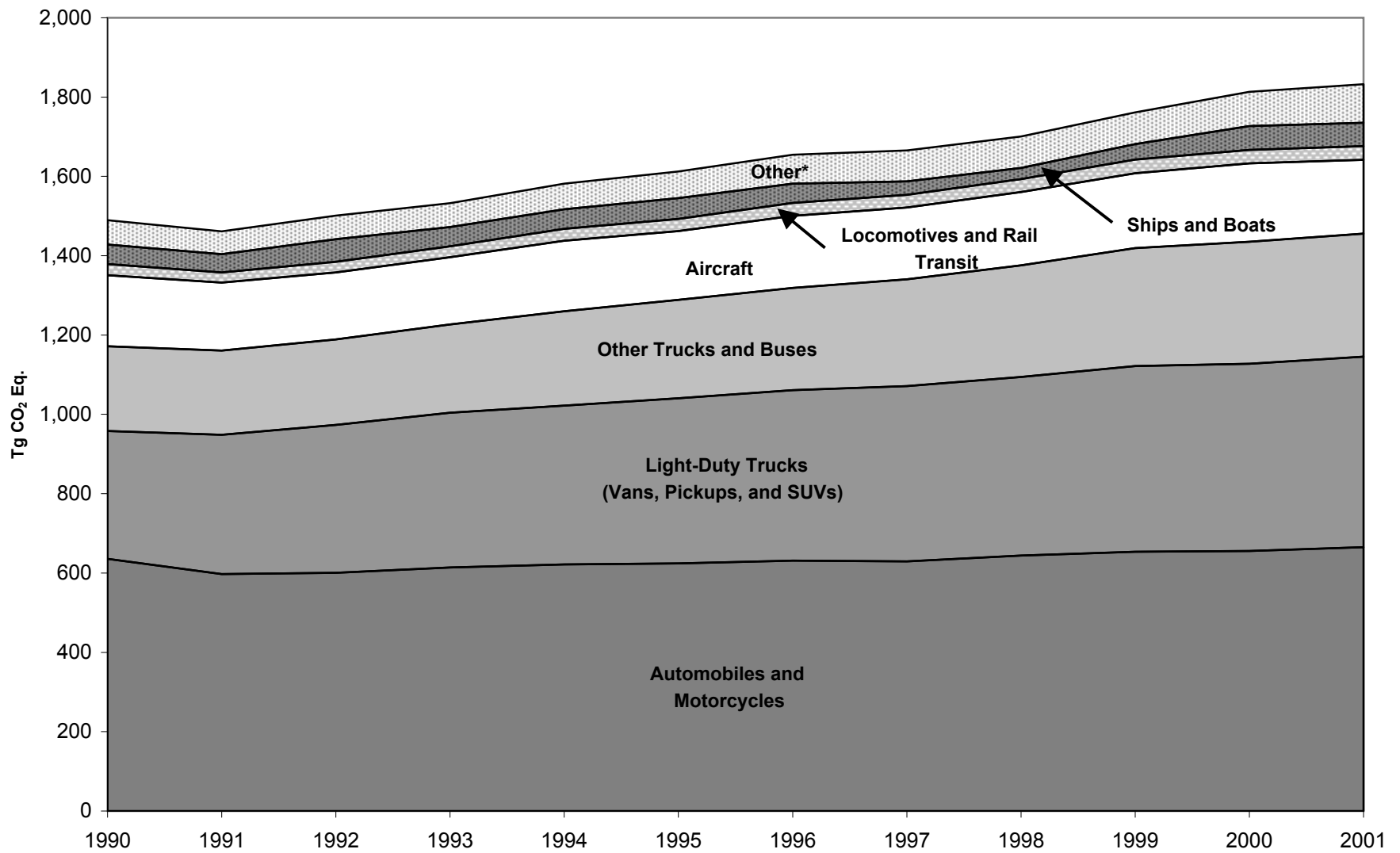
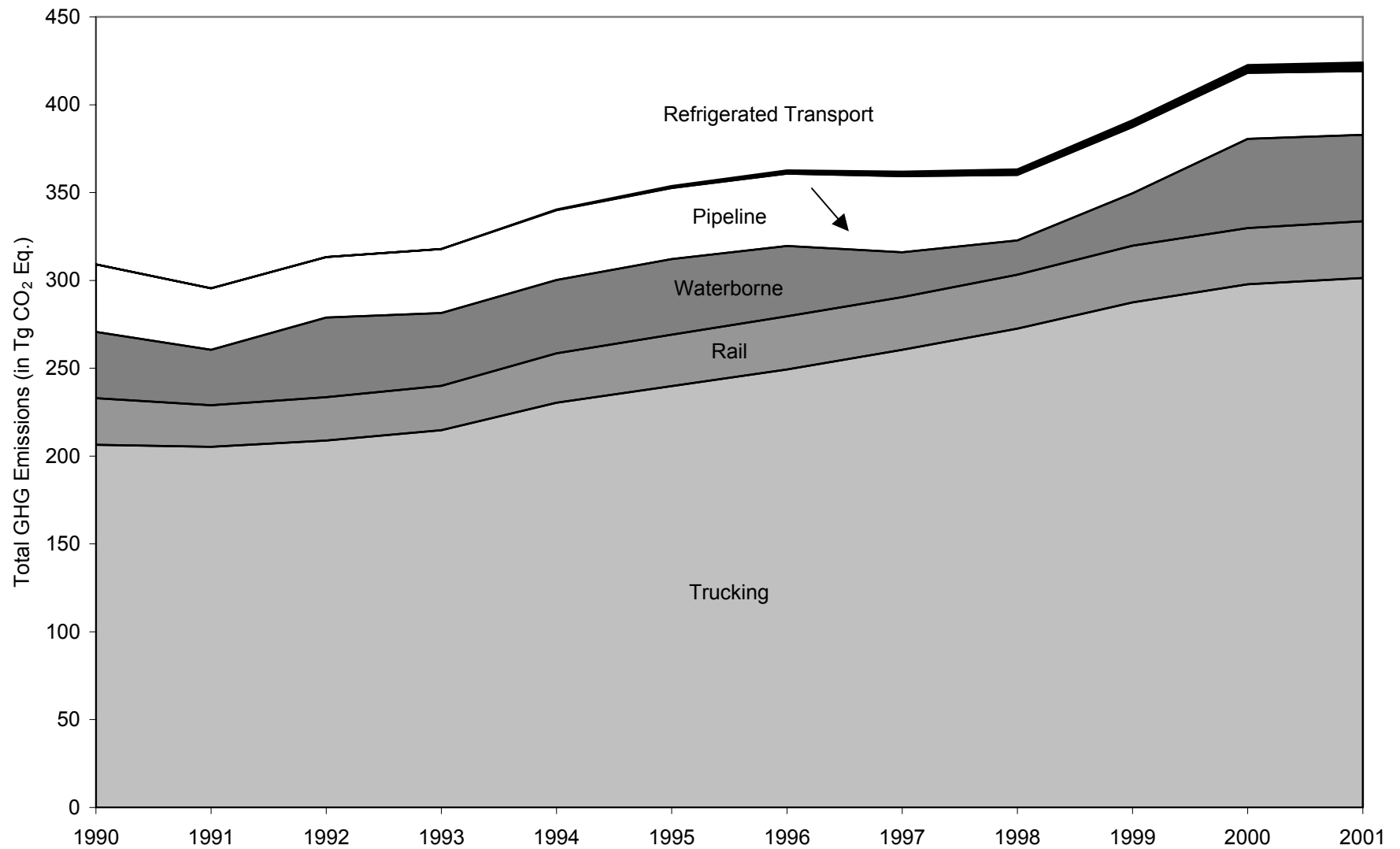
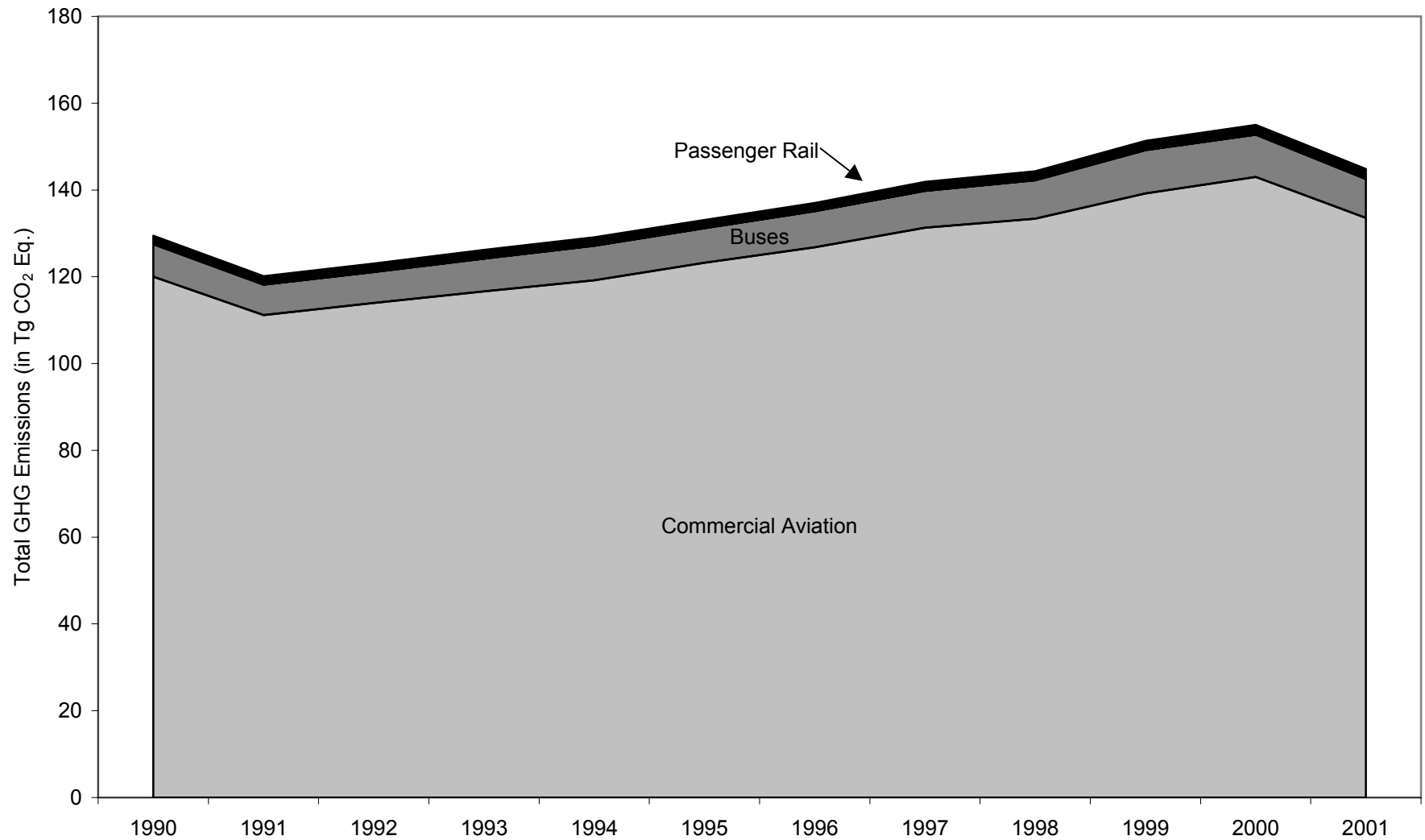


Figure E-2: Greenhouse Gas Emissions from Domestic Freight Transportation by Mode (Tg CO₂ Eq.)



**Figure E-3: Total Greenhouse Gas Emissions from Public Passenger Transportation by Vehicle Type
(Tg CO₂ Eq.)**



ANNEX F

Methodology for Estimating CH₄ Emissions from Coal Mining

The methodology for estimating methane emissions from coal mining consists of two distinct steps. The first step addresses emissions from underground mines. For these mines, emissions are estimated on a mine-by-mine basis and then are summed to determine total emissions. The second step of the analysis involves estimating methane emissions for surface mines and post-mining activities. In contrast to the methodology for underground mines, which uses mine-specific data, the surface mine and post-mining activities analysis consists of multiplying basin-specific coal production by basin-specific emission factors.

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

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

Step 1.1: Estimate Methane Liberated from Ventilation Systems

All coal mines with detectable methane emissions¹ use ventilation systems to ensure that methane levels remain within safe concentrations. Many coal mines do not have detectable levels of methane, while others emit several million cubic feet per day (MMCFD) from their ventilation systems. On a quarterly basis, the U.S. Mine Safety and Health Administration (MSHA) measures methane emissions levels at underground mines. MSHA maintains a database of measurement data from all underground mines with detectable levels of methane in their ventilation air. Based on the four quarterly measurements, MSHA estimates average daily methane liberated at each of the underground mines with detectable emissions.

For the years 1990 through 1996, and 1998 through 2001, MSHA emissions data were obtained for a large but incomplete subset of all mines with detectable emissions. This subset includes mines emitting at least 0.1 MMCFD for some years and at least 0.5 MMCFD for other years, as shown in Table F-1. Well over 90 percent of all ventilation emissions were concentrated in these subsets. For 1997, the complete MSHA database for all 586 mines with detectable methane emissions was obtained. These mines were assumed to account for 100 percent of methane liberated from underground mines. Using the complete database from 1997, the proportion of total emissions accounted for by mines emitting less than 0.1 MMCFD or 0.5 MMCFD was estimated (see Table F-1). The proportion was then applied to the years 1990 through 2001 to account for the less than 10 percent of ventilation emissions coming from mines without MSHA data.

For 1990 through 1999, average daily methane emissions were multiplied by 365 to determine the annual emissions for each mine. For 2000 and 2001, MSHA provided quarterly emissions. The average daily methane emissions were multiplied by the number of days corresponding to the number of quarters the mine vent was operating. For example, if the mine vent was operational in one out of the four quarters, the average daily methane emissions were multiplied by 92 days. Total ventilation emissions for a particular year were estimated by summing emissions from individual mines.

Table F-1: Mine-Specific Data Used to Estimate Ventilation Emissions

Year	Individual Mine Data Used
1990	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)*
1991	1990 Emissions Factors Used Instead of Mine-Specific Data

¹ MSHA records coal mine methane readings with concentrations of greater than 50 ppm (parts per million) methane. Readings below this threshold are considered non-detectable.

1992	1990 Emissions Factors Used Instead of Mine-Specific Data
1993	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)*
1994	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)*
1995	All Mines Emitting at Least 0.5 MMCFD (Assumed to Account for 94.1% of Total)*
1996	All Mines Emitting at Least 0.5 MMCFD (Assumed to Account for 94.1% of Total)*
1997	All Mines with Detectable Emissions (Assumed to Account for 100% of Total)
1998	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)*
1999	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)*
2000	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)*
2001	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)*

* Factor derived from a complete set of individual mine data collected for 1997.

Step 1.2: Estimate Methane Liberated from Degasification Systems

Coal mines use several different types of degasification systems to remove methane, including vertical wells and horizontal boreholes to recover methane prior to mining of the coal seam. Gob wells and cross-measure boreholes recover methane from the overburden (i.e., GOB area) after mining of the seam (primarily in longwall mines).

MSHA collects information about the presence and type of degasification systems in some mines, but does not collect quantitative data on the amount of methane liberated. Thus, degasification emissions were estimated on a mine-by-mine basis based on other sources of available data. Many of the coal mines employing degasification systems have provided EPA with information regarding methane liberated from their degasification systems. For these mines, this reported information was used as the estimate. In other cases in which mines sell methane recovered from degasification systems to a pipeline, gas sales were used to estimate methane liberated from degasification systems (see Step 1.3). Finally, for those mines that do not sell methane to a pipeline and have not provided information to EPA, methane liberated from degasification systems was estimated based on the type of system employed. For example, for coal mines employing gob wells and horizontal boreholes, the methodology assumes that degasification emissions account for 40 percent of total methane liberated from the mine.

Step 1.3: Estimate Methane Recovered from Degasification Systems and Used (Emissions Avoided)

In 2001, ten active coal mines had methane recovery and use projects and sold the recovered methane to a pipeline. One coal mine also used some recovered methane in a thermal dryer in addition to selling gas to a pipeline. In order to calculate emissions avoided from pipeline sales, information was needed regarding the amount of gas recovered and the number of years in advance of mining that wells were drilled. Several state agencies provided gas sales data, which were used to estimate emissions avoided for these projects. Additionally, coal mine operators provided information on gas sales and/or the number of years in advance of mining. Emissions avoided were attributed to the year in which the coal seam was mined. For example, if a coal mine recovered and sold methane using a vertical well drilled five years in advance of mining, the emissions avoided associated with those gas sales (cumulative production) were attributed to the well up to the time it was mined through (e.g., five years of gas production). Where individual well data is not available, estimated percentages of the operator's annual gas sales within the field around the coal mine are attributed to emissions avoidance. For some mines, individual well data were used to assign gas sales to the appropriate emissions avoided year. In most cases, coal mine operators provided this information, which was then used to estimate emissions avoided for a particular year. Additionally, several state agencies provided production data for individual wells.

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

Mine-specific data were not available for estimating methane emissions from surface coal mines or for post-mining activities. For surface mines and post-mining activities, basin-specific coal production was multiplied by a basin-specific emission factor to determine methane emissions.

Step 2.1: Define the Geographic Resolution of the Analysis and Collect Coal Production Data

The first step in estimating methane emissions from surface mining and post-mining activities was to define the geographic resolution of the analysis and to collect coal production data at that level of resolution. The analysis was conducted by coal basin as defined in Table F-2, which presents coal basin definitions by basin and by state.

The Energy Information Administration's (EIA) Coal Industry Annual reports state- and county-specific underground and surface coal production by year. To calculate production by basin, the state level data were grouped into coal basins using the basin definitions listed in Table F-2. For two states—West Virginia and Kentucky—county-level production data was used for the basin assignments because coal production occurred from geologically distinct coal basins within these states. Table F-3 presents the coal production data aggregated by basin.

Step 2.2: Estimate Emissions Factors for Each Emissions Type

Emission factors for surface mined coal were developed from the *in situ* methane content of the surface coal in each basin. Based on an analysis presented in EPA (1993), surface mining emission factors were estimated to be from 1 to 3 times the average *in situ* methane content in the basin. For this analysis, the surface mining emission factor was determined to be twice the *in situ* methane content in the basin. Furthermore, the post-mining emission factors used were estimated to be 25 to 40 percent of the average *in situ* methane content in the basin. For this analysis, the post-mining emission factor was determined to be 32.5 percent of the *in situ* methane content in the basin. Table F-4 presents the average *in situ* content for each basin, along with the resulting emission factor estimates.

Step 2.3: Estimate Methane Emitted

The total amount of methane emitted was calculated by multiplying the coal production in each basin by the appropriate emission factors.

Total annual methane emissions are equal to the sum of underground mine emissions plus surface mine emissions plus post-mining emissions. Table F-5 and Table F-6 present estimates of methane liberated, used, and emitted for 1990 through 2001. Table F-7 provides emissions by state.

Table F-2: Coal Basin Definitions by Basin and by State

Basin	States
Northern Appalachian Basin	Maryland, Ohio, Pennsylvania, West Virginia North
Central Appalachian Basin	Kentucky East, Tennessee, Virginia, West Virginia South
Warrior Basin	Alabama, Mississippi
Illinois Basin	Illinois, Indiana, Kentucky West
South West and Rockies Basin	Arizona, California, Colorado, New Mexico, Utah
North Great Plains Basin	Montana, North Dakota, Wyoming
West Interior Basin	Arkansas, Iowa, Kansas, Louisiana, Missouri, Oklahoma, Texas
Northwest Basin	Alaska, Washington
State	Basin
Alabama	Warrior Basin
Alaska	Northwest Basin
Arizona	South West and Rockies Basin
Arkansas	West Interior Basin
California	South West and Rockies Basin
Colorado	South West and Rockies Basin
Illinois	Illinois Basin
Indiana	Illinois Basin
Iowa	West Interior Basin
Kansas	West Interior Basin
Kentucky East	Central Appalachian Basin
Kentucky West	Illinois Basin
Louisiana	West Interior Basin
Maryland	Northern Appalachian Basin
Mississippi	Warrior Basin
Missouri	West Interior Basin
Montana	North Great Plains Basin
New Mexico	South West and Rockies Basin
North Dakota	North Great Plains Basin
Ohio	Northern Appalachian Basin
Oklahoma	West Interior Basin

Pennsylvania.	Northern Appalachian Basin
Tennessee	Central Appalachian Basin
Texas	West Interior Basin
Utah	South West and Rockies Basin
Virginia	Central Appalachian Basin
Washington	Northwest Basin
West Virginia South	Central Appalachian Basin
West Virginia North	Northern Appalachian Basin
Wyoming	North Great Plains Basin

Table F-3: Annual Coal Production (Thousand Short Tons)

Underground Coal Production

Basin	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
N. Appalachia	103,865	103,450	105,220	77,032	100,122	98,103	106,729	112,135	116,718	107,575	105,374	107,025
Cent. Appalachia	198,412	181,873	177,777	164,845	170,893	166,495	171,845	177,720	171,279	157,058	150,584	152,457
Warrior	17,531	17,062	15,944	15,557	14,471	17,605	18,217	18,505	17,316	14,799	15,895	15,172
Illinois	69,167	69,947	73,154	55,967	69,050	69,009	67,046	64,728	64,463	63,529	53,720	54,364
S. West/Rockies	32,754	31,568	31,670	35,409	41,681	42,994	43,088	44,503	45,983	46,957	45,742	51,193
N. Great Plains	1,722	2,418	2,511	2,146	2,738	2,018	2,788	2,854	1,723	1,673	1,210	0
West Interior	105	26	59	100	147	25	137	212	247	200	241	416
Northwest	0	0	0	0	0	0	0	0	0	0	0	0
Total	423,556	406,344	406,335	351,056	399,102	396,249	409,850	420,657	417,729	391,791	372,766	380,627

Surface Coal Production

Basin	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
N. Appalachia	60,761	51,124	50,512	48,641	44,960	39,372	39,788	40,179	41,043	33,928	34,908	35,972
Cent. Appalachia	94,343	91,785	95,163	94,433	106,129	106,250	108,869	113,275	108,345	107,507	110,479	117,814
Warrior	11,413	10,104	9,775	9,211	8,795	7,036	6,420	5,963	5,697	4,723	4,252	4,945
Illinois	72,000	63,483	58,814	50,535	51,868	40,376	44,754	46,862	47,715	40,474	33,631	41,028
S. West/Rockies	43,863	42,985	46,052	48,765	49,119	46,643	43,814	48,374	49,635	50,349	49,587	52,180
N. Great Plains	249,356	259,194	258,281	275,873	308,279	331,367	343,404	349,612	385,438	407,683	407,670	438,367
West Interior	64,310	61,889	63,562	60,574	58,791	59,116	60,912	59,061	57,951	58,309	54,170	50,616
Northwest	6,707	6,579	6,785	6,340	6,460	6,566	6,046	5,945	5,982	5,666	5,911	6,138
Total	602,753	587,143	588,944	594,372	634,401	636,726	654,007	669,271	699,608	708,639	700,608	747,062

Total Coal Production

Basin	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
N. Appalachia	164,626	154,574	155,732	125,673	145,082	137,475	146,517	152,314	157,761	141,145	140,282	142,998
Cent. Appalachia	292,755	273,658	272,940	259,278	277,022	272,745	280,714	290,995	279,624	262,660	261,063	270,271
Warrior	28,944	27,166	25,719	24,768	23,266	24,641	24,637	24,468	23,013	19,499	20,147	20,116
Illinois	141,167	133,430	131,968	106,502	120,918	109,385	111,800	111,590	110,176	103,966	87,351	95,392
S. West/Rockies	76,617	74,553	77,722	84,174	90,800	89,637	86,902	92,877	95,618	96,207	95,239	103,373
N. Great Plains	251,078	261,612	260,792	278,019	311,017	333,385	346,192	352,466	387,161	406,324	408,880	438,367
West Interior	64,415	61,915	63,621	60,674	58,938	59,141	61,049	59,273	58,198	58,509	54,411	51,032
Northwest	6,707	6,579	6,785	6,340	6,460	6,566	6,046	5,945	5,982	5,665	5,911	6,138
Total	1,026,309	993,487	995,279	945,428	1,033,503	1,032,975	1,063,857	1,089,928	1,118,132	1,093,975	1,073,374	1,127,689

Source for 1990-99 data: EIA (1990-99), Coal Industry Annual. U.S. Department of Energy, Washington, DC, Table 3.

Source for 2000 data: EIA (2001) Personal Communication on August 29, 2001, U.S. Department of Energy, Washington, DC.

Note: Totals may not sum due to independent rounding.

Table F-4: Coal Surface and Post-Mining Methane Emission Factors (ft³ per Short Ton)

Basin	Surface Average <i>in situ</i> Content	Underground Average <i>In situ</i> Content	Surface Mine Factors	Post-Mining Surface Factors	Post Mining Underground
Northern Appalachia	49.3	171.7	98.6	16.0	55.8
Central Appalachia	49.3	330.7	98.6	16.0	107.5
Warrior	49.3	318.0	98.6	16.0	103.4
Illinois	39.0	57.20	78.0	12.7	18.6
S. West/Rockies	15.3	225.8	30.6	5.0	73.4
N. Great Plains	3.2	41.67	6.4	1.0	13.5
West Interior	3.2	41.67	6.4	1.0	13.5
Northwest	3.2	41.67	6.4	1.0	13.5

Source: EPA (1993), Anthropogenic Methane Emissions in the United States: Estimates for 1990, Report to Congress, U.S. Environmental Protection Agency, Air and Radiation, April.

Table F-5: Underground Coal Mining Methane Emissions (Billion Cubic Feet)

Activity	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Ventilation Output	112	NA	NA	95	96	102	90	96	94	92	87	84
Adjustment Factor for Mine Data*	97.8%	NA	NA	97.8%	97.8%	91.4%	91.4%	100%	97.8%	97.8%	97.8%	97.8%
Adjusted Ventilation Output	114	NA	NA	97	98	111	99	96	96	94	89	86
Degasification System Liberated	54	NA	NA	45	46	46	50	42	49	41	45	48
Total Underground Liberated	167	164	162	142	144	157	149	138	146	135	134	135
Recovered & Used	(14)	(15)	(17)	(23)	(27)	(30)	(36)	(28)	(35)	(32)	(36)	(40)
Total	154	149	144	119	117	127	113	110	110	103	98	95

* Refer to Table F-1.

Note: Totals may not sum due to independent rounding.

Table F-6: Total Coal Mining Methane Emissions (Billion Cubic Feet)

Activity	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Underground Mining	154	149	144	119	117	127	113	110	110	103	98	95
Surface Mining	25	23	23	23	24	22	23	24	23	22	22	24
Post-Mining (Underground)	33	31	30	27	30	30	31	32	31	29	28	29
Post-Mining (Surface)	4	4	4	4	4	4	4	4	4	4	4	4
Total	216	209	201	173	175	183	172	170	163	161	151	151

Note: Totals may not sum due to independent rounding.

Table F-7: Total Coal Mining Methane Emissions by State (Million Cubic Feet)

State	1990	1993	1994	1995	1996	1997	1998	1999	2000	2001
Alabama	33,175	26,694	30,283	39,334	29,928	26,440	27,058	26,209	24,078	22,648
Alaska	13	12	12	13	11	11	10	12	12	11
Arizona	402	433	464	425	371	417	403	419	466	477
Arkansas	0	0	0	0	0	0	0	0	0	0
California	2	-	-	-	-	-	0	0	0	0
Colorado	10,117	7,038	9,029	8,541	5,795	9,057	9,057	9,296	10,677	10,935
Illinois	10,643	8,737	10,624	11,106	10,890	8,571	7,859	7,812	8,531	7,267
Indiana	3,149	2,623	2,791	2,106	2,480	3,088	3,239	2,980	2,492	3,679
Iowa	3	1	0	-	-	-	0	0	0	0
Kansas	5	3	2	2	2	3	3	3	1	1
Kentucky	21,229	19,823	21,037	19,103	18,292	20,089	19,240	18,255	16,910	17,524
Louisiana	24	23	26	28	24	26	24	22	27	28
Maryland	510	245	256	259	287	296	282	260	345	341
Mississippi	-	-	-	-	-	-	0	2	92	69
Missouri	20	5	6	4	5	3	3	3	3	3
Montana	280	267	310	294	283	305	319	306	285	291
New Mexico	905	1,186	1,223	980	856	961	1,026	1,042	972	1,195
North Dakota	217	238	240	224	222	220	223	232	233	227
Ohio	4,710	4,110	4,377	3,900	3,992	4,313	4,244	3,820	3,443	3,462
Oklahoma	13	14	52	14	14	132	137	209	208	366
Pennsylvania	22,573	26,437	24,026	27,086	26,567	30,339	29,853	24,088	25,208	22,575
Tennessee	800	350	338	366	418	390	309	349	306	372
Texas	415	406	389	392	410	397	391	395	361	335
Utah	4,562	4,512	3,696	3,541	4,061	4,807	5,060	4,851	4,045	3,389
Virginia	45,883	30,457	26,765	19,893	19,847	16,972	14,087	13,539	12,179	11,621
Washington	37	35	36	36	34	33	35	31	32	34
West Virginia	55,280	37,803	36,854	42,992	42,870	40,197	43,511	41,500	37,507	41,464
Wyoming	1,382	1,578	1,782	1,977	2,090	2,122	2,351	2,520	2,533	2,743
Total	216,350	173,029	174,622	182,616	169,750	169,190	168,725	158,153	150,945	150,860

+ Does not exceed 0.5 Million Cubic Feet

Note: The emission estimates provided above are inclusive of emissions from underground mines, surface mines and post-mining activities. The following states have neither underground nor surface mining and thus report no emissions as a result of coal mining: Connecticut, Delaware, Florida, Georgia, Hawaii, Idaho, Maine, Massachusetts, Michigan, Minnesota, Nebraska, Nevada, New Hampshire, New Jersey,

New York, North Carolina, Oregon, Rhode Island, South Carolina, South Dakota, Vermont, and Wisconsin. Emission estimates are not given for 1991 and 1992 because underground mine data was not available for those years.

ANNEX G

Methodology for Estimating CH₄ Emissions from Natural Gas Systems

The following steps were used to estimate methane emissions from natural gas systems.

Step 1: Calculate Emission Estimates for Base Year 1992 Using GRI/EPA Study

The first step in estimating methane emissions from natural gas systems was to develop a detailed base year estimate of emissions. The study by GRI/EPA (1996) divides the industry into four stages to construct a detailed emission inventory for the year 1992. These stages include: field production, processing, transmission and storage (i.e., both underground and liquefied gas storage), and distribution. This study produced emission factors and activity data for over 100 different emission sources within the natural gas system. Emissions for 1992 were estimated by multiplying activity levels by emission factors for each system component and then summing by stage. Since publication, the EPA has updated activity data for some of the components in the system. Table G-1 displays the 1992 GRI/EPA activity levels and emission factors for venting and flaring from the field production stage, and the current EPA activity levels and emission factors. These data are shown to illustrate the kind of data used to calculate emissions from all stages.

Step 2: Collect Aggregate Statistics on Main Driver Variables

As detailed data on each of the over 100 sources were not available for the period 1990 through 2001, activity levels were estimated using aggregate statistics on key drivers, including: number of producing wells (API 2002, EIA 2002d), number of gas plants (AGA 1990 through 1998; OGJ 1999 through 2002), miles of transmission pipeline (OPS 2002a), miles of distribution pipeline (OPS 2002b), miles of distribution services (OPS 2002b), energy consumption (EIA 2001, 2002c, 2002f). Data on the distribution of gas mains and services by material type was not available for 1990 through 1992 from OPS. For those years, the distribution by type was back calculated from 1993 using compound growth rates determined for the years 1993 through 2000. Table G-2 provides the activity levels of some of the key drivers in the natural gas analysis.

Step 3: Estimate Emission Factor Changes Over Time

In the past, emissions factors were reduced at a rate of 0.2 percent per year such that by year 2020, emissions factors would have declined by 5 percent from 1995. These reductions were made to reflect underlying technological improvements through both innovation and normal replacement of equipment. However, the analysis already incorporates the emissions reductions from some of these technological improvements as reported by EPA's Natural Gas STAR Partners. Thus, to eliminate this double counting, the emissions factors were kept constant throughout the time series for this year's Inventory.

Step 4: Estimate Emissions for Each Year and Stage

Emissions from each stage of the natural gas industry were estimated by multiplying the activity factors by the appropriate emission factors, summing all sources for each stage, and then subtracting the Natural Gas STAR emission reductions. Methane reductions from the Natural Gas STAR program for the years 1990 through 2000 are presented in Table G-3. Emission reductions by project are reported by industry partners using actual measurement data or equipment-specific emission factors. Before incorporating the reductions into the Inventory, quality assurance and quality control checks are undertaken to identify errors, inconsistencies, or irregular data. Total emissions were estimated by adding the emission estimates from each stage. Table G-4 illustrates emission estimates for venting and flaring emissions from the field production stage using this methodology. Table G-5 presents total natural gas production and associated methane emissions.

Table G-1: 1992 Data and Emissions (Mg) for Venting and Flaring from Natural Gas Field Production Stage

Activity	GRI/EPA Values			EPA Adjusted Values		
	Activity Data	Emission Factor	Emissions	Activity Data	Emission Factor	Emissions
Drilling and Well Completion						
Completion Flaring	844 compl/yr	733 Scf/comp	12	400 compl/yr	733 scf/comp	6
Normal Operations						
Pneumatic Device Vents	249,111 controllers	345 Scfd/device	602,291	249,111 controllers	345 scfd/device	602,291
Chemical Injection Pumps	16,971 active pumps	248 Scfd/pump	29,501	16,971 active pumps	248 scfd/pump	29,502
Kimray Pumps	11,050,000 MMscf/yr	368 Scf/MMscf	78,024	7,380,194 MMscf/yr	992 scf/MMscf	140,566
Dehydrator Vents	12,400,000 MMscf/yr	276 Scf/MMscf	65,608	8,200,215 MMscf/yr	276 scf/MMscf	43,387
Compressor Exhaust Vented						
Gas Engines	27,460 MMHPhr	0.24 Scf/HPhr	126,536	27,460 MMHPhr	0.24 scf/HPhr	126,535
Routine Maintenance						
Well Workovers						
Gas Wells	9,392 w.o./yr	2,454 scfy/w.o.	443	9,392 w.o./yr	2,454 scfy/w.o.	443
Well Clean Ups (LP Gas Wells)	114,139 LP gas wells	49,570 scfy/LP well	108,631	114,139 LP gas wells	49,570 scfy/LP well	108,631
Blowdowns						
Vessel BD	255,996 vessels	78 scfy/vessel	383	242,306 vessels	78 scfy/vessel	363
Pipeline BD	340,000 miles (gath)	309 scfy/mile	2,017	340,200 miles (gath)	309 scfy/mile	2,018
Compressor BD	17,112 compressors	3,774 scfy/comp	1,240	17,112 compressors	3,774 scfy/comp	1,240
Compressor Starts	17,112 compressors	8,443 scfy/comp	2,774	17,112 compressors	8,443 scfy/comp	2,774
Upsets						
Pressure Relief Valves	529,440 PRV	34.0 scfy/PRV	346	529,440 PRV	34.0 scfy/PRV	346
ESD	1,115 platforms	256,888 scfy/plat	5,499	1,372 platforms	256,888 scfy/plat	6,767
Mishaps	340,000 miles	669 scfy/mile	4,367	340,200 miles	669 scfy/mile	4,370

Table G-2: Activity Factors for Key Drivers

Variable	Units	1990	1995	1996	1997	1998	1999	2000	2001
Transmission Pipelines Length	miles	291,990	296,947	292,186	294,304	302,706	296,581	293,774	278,269
Wells									
GSAM Appalachia Wells*	# wells	120,443	122,805	122,700	120,037	117,878	118,723	116,702	116,702
GSAM N Central Associated Wells*	# wells	3,780	3,641	3,417	3,409	3,361	2,874	2,439	2,278
GSAM N Central Non-Associated Wells*	# wells	3,277	7,234	7,844	8,910	8,917	8,800	9,113	9,113
GSAM Rest of US Wells*	# wells	145,380	168,502	171,267	182,024	190,134	174,898	180,424	180,424
GSAM Rest of US Associated Wells*	# wells	270,958	264,837	264,807	264,385	254,848	251,686	245,967	244,557
Appalach. + N. Central Non-Assoc. + Rest of US	# wells	269,100	298,541	301,811	310,971	316,929	302,421	306,239	306,239
Platforms									
Gulf of Mexico Off-shore Platforms	# platforms	3,798	3,868	3,846	3,846	3,963	3,975	4,019	4,009
Rest of U.S. (offshore platforms)	# platforms	24	23	24	23	23	23	23	23
N. Central Non-Assoc. + Rest of US Wells	# platforms	148,657	175,736	179,111	190,934	199,051	183,698	189,537	189,537
Gas Plants									
Number of Gas Plants	# gas plants	761	675	623	615	558	581	585	570
Distribution Services									
Steel – Unprotected	# of services	5,500,993	6,151,653	5,775,613	5,518,795	5,463,253	5,751,250	5,676,582	5,855,612
Steel - Protected	# of services	19,916,202	21,002,455	18,593,770	19,078,467	18,478,344	18,310,719	17,775,878	17,828,261
Plastic	# of services	16,269,414	26,044,545	26,187,536	27,800,401	28,629,388	28,796,952	31,644,014	33,144,535
Copper	# of services	1,379,237	1,445,380	1,519,625	1,498,050	1,464,019	1,458,518	1,434,091	1,395,232
Total	# of services	43,065,846	54,644,033	52,076,544	53,895,713	54,035,004	54,317,439	56,530,565	58,223,640
Distribution Mains									
Steel – Unprotected	miles	91,267	94,058	88,412	85,166	86,639	84,534	82,817	81,258
Steel – Protected	miles	491,120	503,288	484,526	479,278	484,963	459,298	468,932	484,451
Cast Iron	miles	52,644	50,625	51,542	47,669	47,587	45,865	44,736	47,443
Plastic	miles	202,269	353,735	350,699	385,373	400,627	415,210	446,554	504,199
Total	miles	837,300	1,001,706	975,179	997,486	1,019,816	1,004,907	1,043,039	1,117,351

* GSAM (Gas Systems Analysis Model) is a natural gas supply, demand, and transportation model used by the Federal Energy Technology Center of the U.S. Department of Energy (GSAM 1997).

Table G-3. Methane reductions from the Natural Gas STAR program (Tg)

Process	1990	1995	1996	1997	1998	1999	2000	2001
Production	.01	0.09	0.17	0.22	0.26	0.29	0.31	0.33
Processing	--	0.00	0.00	0.00	0.02	0.03	0.03	0.03
Transmission and Storage	--	0.12	0.10	0.13	0.18	0.22	0.27	0.34
Distribution	--	0.02	0.02	0.03	0.02	0.02	0.02	0.02

Table G-4: CH₄ Emission Estimates for Venting and Flaring from the Field Production Stage (Mg)

Activity	1990	1995	1996	1997	1998	1999	2000	2001
Drilling and Well Completion								
Completion Flaring	5.5	6.1	6.2	6.4	6.5	6.2	6.3	6.3
Normal Operations								
Pneumatic Device Vents	589,673	697,087	710,474	757,372	789,570	728,669	751,831	751,831
Chemical Injection Pumps	37,761	45,545	46,547	49,768	51,783	47,943	49,476	49,476
Kimray Pumps	137,344	152,210	153,856	158,434	161,408	154,106	156,002	156,002
Dehydrator Vents	42,392	46,981	47,489	48,902	49,820	47,566	48,151	48,151
Compressor Exhaust Vented Gas Engines	123,884	146,451	149,263	159,116	165,881	153,086	157,952	157,952
Routine Maintenance								
Well Workovers Gas Wells	543	602	609	627	639	610	617	617
Well Clean Ups (LP Gas Wells)	103,451	114,649	115,888	119,337	121,577	116,076	117,505	117,505
Blowdowns								
Vessel BD	265	307	312	329	340	318	326	326
Pipeline BD	1,749	1,918	1,938	2,005	2,052	1,956	1,988	1,988
Compressor BD	1,598	1,816	1,840	1,927	1,988	1,860	1,900	1,899
Compressor Starts	3,575	4,062	4,116	4,311	4,448	4,162	4,250	4,249
Upsets								
Pressure Relief Valves	338	400	408	435	453	418	431	431
ESD	6,764	6,882	6,848	6,843	7,048	7,069	7,146	7,129
Mishaps	947	1,038	1,049	1,085	1,111	1,058	1,076	1,076

Table G-5: U.S. Total Natural Gas Production (Trillion Ft³/yr) and Associated CH₄ Emissions (Gg)

Activity	1990	1995	1996	1997	1998	1999	2000	2001
Production	17.8	18.6	18.9	18.9	19.0	18.8	19.0	19.4
CH ₄ Emissions from Production	1,445	1,583	1,537	1,577	1,605	1,463	1,488	1,467

ANNEX H

Methodology for Estimating CH₄ Emissions from Petroleum Systems

The methodology for estimating methane emissions from petroleum systems is based on the 1999 EPA draft report, *Estimates of Methane Emissions from the U.S. Oil Industry* (EPA 1999) and the study, *Methane Emissions from the U.S. Petroleum Industry* (Radian 1996). Seventy activities that emit methane from petroleum systems were examined for these reports. Most of the activities analyzed involve crude oil production field operations, which accounted for 97 percent of total oil industry emissions. Crude transportation and refining accounted for the remaining emissions at about one and two percent each, respectively.

The following steps were taken to estimate methane emissions from petroleum systems.

Step 1: Determine Emission Factors for all Activities

The emission factors for sixty-nine of the seventy activities for 1995 are taken from the 1999 EPA draft report, which contains the most recent and comprehensive determination of methane emission factors for the seventy methane emitting activities in the oil industry. For the one activity, gas engines in the production sector, the emission factor is taken from Radian (1996). The emission factors determined for 1995 were assumed to be representative of emissions from each source type over the period 1990 through 2001. Therefore, the same emission factors are used for each year throughout this period.

Step 2: Determine Activity Levels for Each Year

Activity levels change from year to year. Some factors change in proportion to crude oil rates: production, transportation, refinery runs. Some change in proportion to the number of facilities: oil wells, petroleum refineries. Some factors change proportional to both rate and number of facilities.

For fifty-seven activities, activity levels for 1995 are taken from EPA (1999). For the remaining thirteen activities, the activity levels for 1993 are taken from Radian (1996). These thirteen activity levels were derived from field data collected in 1993, along with 1993 crude oil production and number of wells.

For both sets of data, a determination is made on a case-by-case basis as to which measure of petroleum industry activity best reflects the change in annual activity relative to the base years (1993 and 1995). Publicly reported data from the Minerals Management Service (MMS), Energy Information Administration (EIA), American Petroleum Institute (API), and the Oil & Gas Journal (O&GJ) are used to extrapolate the activity levels from the base year to each year between 1990 and 2001. Data used include total domestic crude oil production, number of domestic crude oil wells, total imports and exports of crude oil, and total petroleum refinery crude runs. The activity data for the transportation sector were not yet available. In this case, it was assumed that all the crude oil that is transported goes to refineries. Therefore, the activity data for the refining sector was used also for the transportation sector. For a small number of sources, 2001 data were not yet available. In these cases, the 2000 activity factors were used. In the few cases where no data was located, oil industry data based on expert judgment was used.

Step 3: Estimate Methane Emissions for Each Activity for Each Year

Annual emissions from each of the 70 petroleum system activities were estimated by multiplying the activity data for each year by the corresponding emission factor. These annual emissions for each activity were then summed to estimate the total annual methane emissions. For the production sector, the amount of emission reduction achieved by the EPA's Natural Gas STAR program was subtracted from the estimated production emissions. Table H-1, Table H-2 and Table H-3 provide 2001 activity factors, emission factors and emission estimates.

Methane emissions from the Natural Gas STAR program for the years 1990 through 2001 are presented in Table H-4. Table H-5 provides a summary of emission estimates for the years 1990 through 2001.

Table H-1: 2001 CH₄ Emissions from Petroleum Production Field Operations

Activity/Equipment	Emission Factor Units	Activity Factor	Units	Emissions (Bcf/yr)
Vented Emissions				48.027
Oil Tanks	18 scf of CH ₄ /bbl crude	1,251	MMbbl/yr (non stripper wells)	22.086
Pneumatic Devices, High Bleed	345 scfd CH ₄ /device	142,872	No. of high-bleed devices	17.998
Pneumatic Devices, Low Bleed	35 scfd CH ₄ /device	265,334	No. of low-bleed devices	3.342
Chemical Injection Pumps	248 scfd CH ₄ /pump	28,595	No. of pumps	2.589
Vessel Blowdowns	78 scfy CH ₄ /vessel	186,546	No. of vessels	0.015
Compressor Blowdowns	3,775 scf/yr of CH ₄ /compressor	2,532	No. of compressors	0.010
Compressor Starts	8,443 scf/yr. of CH ₄ /compressor	2,532	No. of compressors	0.021
Stripper wells	2,345 scf/yr of CH ₄ /stripper well	329,434	No. of stripper wells vented	0.818
Well Completion Venting	733 scf/completion	4,731	Oil well completions	0.003
Well Workovers	96 scf CH ₄ /workover	40,050	Oil well workovers	0.004
Pipeline Pigging	2.40 scfd of CH ₄ /pig station	0	No. of crude pig stations	0.000
Offshore Platforms, Gulf of Mexico	1,283 scfd CH ₄ /platform	1,832	No. of oil platforms	0.858
Offshore Platforms, Other U.S. Areas	1,283 scfd CH ₄ /platform	23	No. of oil platforms	0.011
Fugitive Emissions				2.587
Offshore Platforms, Gulf of Mexico	56 scfd CH ₄ /platform	1,832	No. of oil platforms	0.037
Offshore Platforms, Other U.S. Areas	56 scfd CH ₄ /platform	23	No. of oil platforms	0.000
Oil Wellheads (heavy crude)	0.13 scfd/well	14,422	No. of hvy. crude wells *	0.001
Oil Wellheads (light crude)	16.6 scfd/well	190,144	No. of lt. crude wells *	1.045
Separators (heavy crude)	0.15 scfd CH ₄ /separator	10,972	No. of hvy. crude seps.	0.001
Separators (light crude)	14 scfd CH ₄ /separator	99,858	No. of lt. crude seps.	0.505
Heater/Treaters (light crude)	19 scfd CH ₄ /heater	75,716	No. of heater treaters	0.530
Headers (heavy crude)	0.08 scfd CH ₄ /header	13,929	No. of hvy. crude hdrs.	0.000
Headers (light crude)	11 scfd CH ₄ /header	43,183	No. of lt. crude hdrs.	0.171
Floating Roof Tanks	338,306 scf CH ₄ /floating roof tank/yr.	24	No. of floating roof tanks	0.008
Compressors	100 scfd CH ₄ /compressor	2,532	No. of compressors	0.092
Large Compressors	16,360 scfd CH ₄ /compressor	0	No. of large comprs.	0.000
Sales Areas	41 scf CH ₄ /loading	1,764,218	Loadings/year	0.071
Pipelines	0 scfd of CH ₄ /mile of pipeline	30,467	Miles of gathering line	0.000
Well Drilling	0 scfd of CH ₄ /oil well drilled	7,437	No. of oil wells drilled	0.000
Battery Pumps	0.24 scfd of CH ₄ /pump	160,200	No. of battery pumps	0.014
Combustion Emissions				4.186
Gas Engines	0.24 scf CH ₄ /HP-hr	15,950	MMHP-hr	3.828
Heaters	0.52 scf CH ₄ /bbl	2117.4	MBbl/yr	0.001
Well Drilling	2,453 scf CH ₄ /well drilled	7,437	Oil wells drilled, 1995	0.018
Flares	20 scf CH ₄ /per Mcf flared	492,582	Mcf flared/yr	0.010
Offshore Platforms, Gulf of Mexico	481 scfd CH ₄ /platform	1,852	No. of oil platforms	0.325
Offshore Platforms, Other U.S. Areas	481 scfd CH ₄ /platform	23	No. of oil platforms	0.004
Process Upset Emissions				0.561
Platform Emergency Shutdowns	256,888 scfy/platform	1,875	No. of platforms	0.482
Pressure Relief Valves	35 scf/yr/PR valve	176,866	No. of PR valves	0.006
Well Blowouts Offshore	5.0 MMscf/blowout	2.25	No. of blowouts/yr	0.011
Well Blowouts Onshore	2.5 MMscf/blowout	24.8	No. of blowouts/yr	0.062
Total (excluding stripper wells)				55.36

Table H-2: 2001 CH₄ Emissions from Petroleum Transportation

Activity/Equipment	Emission Factor	Units	Activity Factor	Units	Emissions (Bcf/yr)
Vented Emissions					0.216
Tanks	0.021	scf CH ₄ /yr/bbl of crude delivered to refineries	5,522	MMbbl crude feed/yr	0.114
Truck Loading	0.520	scf CH ₄ /yr/bbl of crude transported by truck	45.3	MMbbl crude feed/yr	0.024
Marine Loading	2.544	scf CH ₄ /1000 gal. crude marine loadings	23,713,616	1,000 gal./yr loaded	0.060
Rail Loading	0.520	scf CH ₄ /yr/bbl of crude transported by rail	7.4	MMbbl. Crude by rail/yr	0.004
Pump Station Maintenance	36.80	scf CH ₄ /station/yr	490	No. of pump stations	0.000
Pipeline Pigging	39	scfd of CH ₄ /pig station	980	No. of pig stations	0.014
Fugitive Emissions					0.050
Pump Stations	25	scfCH ₄ /mile/yr.	48,990	No. of miles of crude p/l	0.001
Pipelines	0	scf CH ₄ /bbl crude transported by pipeline	7,551	MM bbl crude piped	0.000
Floating Roof Tanks	58,965	scf CH ₄ /floating roof tank/yr.	824	No. of floating roof tanks	0.049
Combustion Emissions					0.000
Pump Engine Drivers	0.24	scf CH ₄ /hp-hr	NA	No. of hp-hrs	NA
Heaters	0.521	scf CH ₄ /bbl.burned	NA	No. of bbl. Burned	NA
Total					0.283

Table H-3: 2001 CH₄ Emissions from Petroleum Refining

Activity/Equipment	Emission Factor	Units	Activity Factor	Units	Emissions (Bcf/yr)
Vented Emissions					1.223
Tanks	20.6	scfCH ₄ /Mbbbl	1,941	Mbbbl/cd heavy crude feed	0.015
System Blowdowns	137	scfCH ₄ /Mbbbl	15,128	Mbbbl/cd refinery feed	0.755
Asphalt Blowing	2,555	scfCH ₄ /Mbbbl	485	Mbbbl/cd production	0.453
Fugitive Emissions					0.091
Fuel Gas System	439	McfCH ₄ /refinery/yr	153	Refineries	0.067
Floating Roof Tanks	587	scf CH ₄ /floating roof tank/yr.	767	No. of floating roof tanks	0.000
Wastewater Treating	1.88	scfCH ₄ /Mbbbl	15,128	Mbbbl/cd refinery feed	0.010
Cooling Towers	2.36	scfCH ₄ /Mbbbl	15,128	Mbbbl/cd refinery feed	0.013
Combustion Emissions					0.092
Atmospheric Distillation	3.61	scfCH ₄ /Mbbbl	15,352	Mbbbl/cd refinery feed	0.020
Vacuum Distillation	3.61	scfCH ₄ /Mbbbl	6,875	Mbbbl/cd feed	0.009
Thermal Operations	6.02	scfCH ₄ /Mbbbl	2,055	Mbbbl/cd feed	0.005
Catalytic Cracking	5.17	scfCH ₄ /Mbbbl	5,194	Mbbbl/cd feed	0.010
Catalytic Reforming	7.22	scfCH ₄ /Mbbbl	3,239	Mbbbl/cd feed	0.009
Catalytic Hydrocracking	7.22	scfCH ₄ /Mbbbl	1,362	Mbbbl/cd feed	0.004
Hydrotreating	2.17	scfCH ₄ /Mbbbl	1,825	Mbbbl/cd feed	0.001
Hydrotreating	6.50	scfCH ₄ /Mbbbl	8,382	Mbbbl/cd feed	0.020
Alkylation/Polymerization	12.6	scfCH ₄ /Mbbbl	1,065	Mbbbl/cd feed	0.005
Aromatics/Isomeration	1.80	scfCH ₄ /Mbbbl	934	Mbbbl/cd feed	0.001
Lube Oil Processing	0.00	scfCH ₄ /Mbbbl	162	Mbbbl/cd feed	0.000
Engines	0.006	scfCH ₄ /hp-hr	1,467	MMhp-hr/yr	0.008
Flares	0.189	scfCH ₄ /Mbbbl	15,128	Mbbbl/cd refinery feed	0.001
Total					1.406

Table H-4: CH₄ Reductions from Natural Gas STAR program (Gg)

Activity	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Production Field Operations	2	7	14	28	48	54	61	75	79	89	89	85
Tank venting	2	7	14	28	48	54	61	75	79	89	89	85
Crude Oil Transportation	-	-	-	-	-	-	-	-	-	-	-	-
Refining	-	-	-	-	-	-	-	-	-	-	-	-

Table H-5: Summary of CH₄ Emissions from Petroleum Systems (Gg)

Activity	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Production Field Operations	1,278	1,289	1,236	1,181	1,141	1,122	1,107	1,090	1,058	996	977	979
Tank venting	558	557	528	486	451	439	425	409	390	349	343	345
Pneumatic device venting	525	535	517	507	504	497	496	495	485	470	460	460
Wellhead fugitives	26	26	24	24	24	25	25	25	25	24	22	22
Combustion & process upsets	103	105	101	99	98	98	98	98	96	92	91	91
Misc. venting & fugitives	65	66	65	64	64	63	63	63	62	61	60	60
Crude Oil Transportation	7	6	6	6	6	6	6	6	6	6	5	5
Refining	25	24	24	25	25	25	26	27	27	27	28	27
Total	1,309	1,320	1,267	1,212	1,172	1,153	1,138	1,123	1,090	1,029	1,010	1,011

Note: Totals may not sum due to independent rounding.

ANNEX I

Methodology for Estimating CO₂ Emissions from Municipal Solid Waste Combustion

Emissions of CO₂ from municipal solid waste (MSW) combustion include CO₂ generated by the combustion of plastics, synthetic rubber and synthetic fibers in MSW, and combustion of synthetic rubber and carbon black in tires. Combustion of MSW also results in emissions of N₂O. The methodology for calculating emissions from each of these waste combustion sources is described in this Annex.

CO₂ from Plastics Combustion

In the *Characterization of Municipal Solid Waste in the United States* reports (EPA 2000c, 2002), the flows of plastics in the U.S. waste stream are reported for seven resin categories. The 2000 quantity generated, recovered, and discarded for each resin is shown in Table I-1. The EPA reports do not provide estimates for individual materials landfilled and combusted, although they do provide such an estimate for the waste stream as a whole. To estimate the quantity of plastics landfilled and combusted, total discards were apportioned based on the proportions of landfilling and combustion for the entire U.S. waste stream in 1998 (76 percent and 24 percent, respectively). Emissions for 1990 through 1998 were calculated using this approach; when distribution by resin category was not reported, total values were apportioned according to 1998 distribution ratios. Generation and recovery figures for 1999 are interpolated from 1998 and 2000 data, while 2001 figures are extrapolated from the year 2000 using the observed growth rate from 1998 to 2000.

Table I-1: 2000 Plastics in the Municipal Solid Waste Stream by Resin (Gg)

Waste Pathway	PET	HDPE	PVC	LDPE/ LLDPE	PP	PS	Other	Total
Generation	2,259	4,382	1,261	5,207	3,039	2,068	4,200	22,417
Recovery	390	381	0	136	9	0	299	1,216
Discard	1,869	4,001	1,261	5,071	3,030	2,068	3,901	21,201
Landfill	1,420	3,041	958	3,854	2,303	1,572	2,965	16,113
Combustion	449	960	303	1,217	727	496	936	5,088
Recovery*	17%	9%	0%	3%	0%	0%	7%	5%
Discard*	83%	91%	100%	97%	100%	100%	93%	95%
Landfill*	63%	69%	76%	74%	76%	76%	71%	72%
Combustion*	20%	22%	24%	23%	24%	24%	22%	23%

*As a percent of waste generation.

Note: Totals may not sum due to independent rounding. Abbreviations: PET (polyethylene terephthalate), HDPE (high density polyethylene), PVC (polyvinyl chloride), LDPE/LLDPE (linear low density polyethylene), PP (polypropylene), PS (polystyrene).

Fossil fuel-based CO₂ emissions for 2000 were calculated as the product of plastic combusted, carbon content, and fraction oxidized (see Table I-2). The carbon content of each of the six types of plastics is listed, with the value for “other plastics” assumed equal to the weighted average of the six categories. The fraction oxidized was assumed to be 98 percent.

Table I-2: 2000 Plastics Combusted (Gg), Carbon Content (%), and Carbon Combusted (Gg)

Factor	PET	HDPE	PVC	LDPE/ LLDPE	PP	PS	Other	Total
Quantity Combusted	449	960	303	1,217	727	496	936	5,088
Carbon Content of Resin	63%	86%	38%	86%	86%	92%	66% ^a	-
Carbon in Resin Combusted	275	807	114	1,022	611	449	604	3,881
Emissions (Tg CO ₂ Eq.) ^b	1.0	3.0	0.4	3.7	2.2	1.6	2.2	14.2

^a Weighted average of other plastics produced in 1998 production.

^b Assumes a fraction oxidized of 98 percent.

Note: Totals may not sum due to independent rounding.

CO₂ from Combustion of Synthetic Rubber and Carbon Black in Tires

Emissions from tire combustion require two pieces of information: the amount of tires combusted and the carbon content of the tires. The *Scrap Tire Use/Disposal Study 1998/1999 Update* (STMC 1999) reports that 114 million of the 270 million scrap tires generated in 1998 (approximately 42 percent of generation) were used for fuel purposes. Using STMC estimates of average tire composition and weight, the weight of synthetic rubber and carbon black in scrap tires was determined. Synthetic rubber in tires was estimated to be 90 percent carbon by weight, based on the weighted average carbon contents of the major elastomers used in new tire consumption (see Table I-3).¹ Carbon black is 100 percent carbon. Multiplying the proportion of scrap tires combusted by the total carbon content of the synthetic rubber and carbon black portion of scrap tires yielded CO₂ emissions, as shown in Table I-4. Note that the disposal rate of rubber in tires (0.4 Tg/yr) is smaller than the consumption rate for tires based on summing the elastomers listed in Table I-3 (1.3 Tg/yr); this is due to the fact that much of the rubber is lost through tire wear during the product's lifetime and due to the lag time between consumption and disposal of tires. Tire production and fuel use for 1998 through 2001 were extrapolated from trend data for 1994 through 1997.

Table I-3: Elastomers Consumed in 1998 (Gg)

Elastomer	Consumed	Carbon Content	Carbon Equivalent
Styrene butadiene rubber solid	908	91%	828
For Tires	743	91%	677
For Other Products*	165	91%	151
Polybutadiene	561	89%	499
For Tires	404	89%	359
For Other Products	157	89%	140
Ethylene Propylene	320	86%	274
For Tires	10	86%	8
For Other Products	310	86%	266
Polychloroprene	69	59%	40
For Tires	0	59%	0
For Other Products	69	59%	40
Nitrile butadiene rubber solid	87	77%	67
For Tires	1	77%	1
For Other Products	86	77%	67
Polyisoprene	78	88%	69
For Tires	65	88%	57
For Other Products	13	88%	12
Others	369	88%	324
For Tires	63	88%	56
For Other Products	306	88%	268
Total	2,392	-	2,101

*Used to calculate carbon content of non-tire rubber products in municipal solid waste.

- Not applicable

Table I-4: Scrap Tire Constituents and CO₂ Emissions from Scrap Tire Combustion in 1998

Material	Weight of Material (Tg)	Carbon Content	Emissions (Tg CO ₂ Eq.)*
Synthetic Rubber	0.7	90%	2.1
Carbon Black	0.9	100%	3.3
Total	1.6	-	5.4

* Assumes a fraction oxidized of 98 percent.

- Not applicable

¹ The carbon content of tires (1,158,000 Tg) divided by for the mass of tires (1,285,000 Tg) equals 90 percent.

CO₂ from Combustion of Synthetic Rubber in Municipal Solid Waste

Similar to the methodology for scrap tires, CO₂ emissions from synthetic rubber in MSW were estimated by multiplying the amount of rubber combusted by an average rubber carbon content. The amount of rubber in the MSW stream was estimated from data provided in the *Characterization of Municipal Solid Waste in the United States* reports (EPA 2000c, 2002). The reports divide rubber found in MSW into three product categories: other durables (not including tires), non-durables (which includes clothing and footwear and other non-durables), and containers and packaging. Since there was negligible recovery for these product types, all the waste generated can be considered discarded. Similar to the plastics method, discards were apportioned based on the proportions of landfilling and combustion for the entire U.S. waste stream (76 percent and 24 percent, respectively). The report aggregates rubber and leather in the MSW stream; an assumed synthetic rubber content was assigned to each product type, as shown in Table I-5.² A carbon content of 85 percent was assigned to synthetic rubber for all product types, according to the weighted average carbon content of rubber consumed for non-tire uses (see Table I-4). For 1999 and 2001, waste generation values were not available, so 1999 values were interpolated from 1998 and 2000 data, and 2001 values were extrapolated from 2000 data based on observed growth rates for 1998 to 2000.

Table I-5: Rubber and Leather in Municipal Solid Waste in 2000

Product Type	Generation (Gg)	Synthetic Rubber (%)	Carbon Content (%)	Emissions (Tg CO ₂ Eq.)*
Durables (not Tires)	2,304	100%	85%	1.7
Non-Durables	306	-	85%	0.2
Clothing and Footwear	122	25%	85%	0.1
Other Non-Durables	184	75%	85%	0.1
Containers and Packaging	27	100%	85%	+
Total	2,638	-	-	2.0

* Assumes a fraction oxidized of 98 percent.

+ Less than 0.05 Tg CO₂ Eq.

- Not applicable

CO₂ from Combustion of Synthetic Fibers

Carbon dioxide emissions from synthetic fibers were estimated as the product of the amount of synthetic fiber discarded annually and the average carbon content of synthetic fiber. Fiber in the MSW stream was estimated from data provided in the *Characterization of Municipal Solid Waste in the United States* (EPA 2000c, 2002) reports for textiles. The amount of synthetic fiber in MSW was estimated by subtracting (a) the amount recovered from (b) the waste generated (see Table I-6). As with the other materials in the MSW stream, discards were apportioned based on the proportions of landfilling and combustion for the entire U.S. waste stream (76 percent and 24 percent, respectively). It was assumed that approximately 55 percent of the fiber was synthetic in origin, based on information received from the Fiber Economics Bureau (DeZan 2000). An average carbon content of 70 percent was assigned to synthetic fiber using the production-weighted average of the carbon contents of the four major fiber types (polyester, nylon, olefin, and acrylic) produced in 1998 (see Table I-7). The equation relating CO₂ emissions to the amount of textiles combusted is shown below. Since 1999 and 2001 values were not provided in the *Characterization* reports, generation and recovery rates for 1999 were interpolated between reported 1998 and 2000 values, while 2001 rates were forecasted by using the observed growth rates (between 1998 and 2000) to extrapolate from the 2000 values.

$$\begin{aligned} \text{CO}_2 \text{ Emissions from the Combustion of Synthetic Fibers} &= \text{Annual Textile Combustion (Gg)} \times \\ &(\text{Percent of Total Fiber that is Synthetic}) \times (\text{Average Carbon Content of Synthetic Fiber}) \times \\ &(44\text{g CO}_2/12 \text{ g C}) \end{aligned}$$

Table I-6: Textiles in MSW (Gg)

² As a biogenic material, the combustion of leather is assumed to have no net carbon dioxide emissions.

Year	Generation	Recovery	Discards	Combustion
1990	2,884	328	2,557	614
1991	3,064	341	2,723	654
1992	3,255	354	2,901	696
1993	3,458	368	3,090	742
1994	3,674	382	3,291	790
1995	3,674	447	3,227	774
1996	3,832	472	3,361	807
1997	4,090	526	3,564	855
1998	4,269	551	3,718	892
1999*	4,468	590	3,877	931
2000	4,666	630	4,036	969
2001**	4,883	675	4,208	1,010

*Interpolated between 1998 and 2000 data (EPA 2000c).

** Extrapolated from 2000 data using observed growth rate between 1998 and 2000.

Table I-7: Synthetic Fiber Production in 1998

Fiber	Production (Tg)	Carbon Content
Polyester	1.8	63%
Nylon	1.3	64%
Olefin	1.3	86%
Acrylic	0.2	68%
Total	4.6	70%

- Not applicable

N₂O from Municipal Solid Waste Combustion

Estimates of N₂O emissions from MSW combustion in the United States are based on the methodology outlined in the EPA's Compilation of Air Pollutant Emission Factors (EPA 1997). According to this methodology, emissions of N₂O from MSW combustion are the product of the mass of MSW combusted, an emission factor of N₂O emitted per unit mass of waste combusted, and an N₂O emissions control removal efficiency. For MSW combustion in the United States, an emission factor of 30 g N₂O/metric ton MSW and an estimated emissions control removal efficiency of zero percent were used. No information was available on the mass of waste combusted in 2001. It was assumed for the purposes of this calculation that the mass of waste combusted in 2001 was the same as estimated for 2000.

ANNEX J

Methodology for Estimating Emissions from International Bunker Fuels used by the U.S. Military

Bunker fuel emissions estimates for the Department of Defense (DoD) were developed using data primarily generated by the Defense Energy Support Center for aviation and naval fuels (DESC 2002). The DESC of the Defense Logistics Agency (DLA) prepared a special report based on data in the Defense Fuels Automated Management System (DFAMS). DFAMS contains data for 1995 through 2001, but the data set was not complete for years prior to 1995. Fuel quantities for 1990 to 1994 were estimated based on a back-calculation of the 1995 DFAMS values using DLA aviation and marine fuel procurement data. The back-calculation was refined in 1999 to better account for the jet fuel conversion from JP4 to JP8 that occurred within the DoD between 1992 and 1995.

Step 1: Omit Extra-Territorial Fuel Deliveries

Beginning with the complete DFAMS data set for each year, the first step in the development of DoD related emissions from international bunker fuels was to identify data that would be representative of international bunker fuel consumption as that term is defined by decisions of the UNFCCC (i.e., fuel sold to a vessel, aircraft, or installation within the United States or its territories and used in international maritime or aviation transport). Therefore, fuel data were categorized by the location of fuel delivery in order to identify and omit all extra-territorial fuel transactions/deliveries (i.e., sales abroad).

Step 2: Allocate JP8 between Aviation and Land-based Vehicles

As a result of DoD¹ and NATO² policies on implementing the Single Fuel For the Battlefield concept, DoD activities have been increasingly replacing diesel fuel with JP8 (a type of jet fuel) in compression ignition and turbine engines in land-based equipment. Based on this concept and examination of all data describing jet fuel used in land-based vehicles, it was determined that a portion of JP8 consumption should be attributed to ground vehicle use. Based on available Service data and expert judgment, it was determined that a small fraction of the total JP8 should be reallocated from the aviation subtotal to a new land-based jet fuel category for 1997 and subsequent years. As a result of this reallocation, the JP8 use reported for aviation will be reduced and the total fuel use for land-based equipment will increase. DoD's total fuel use will not change.

Table J-1 displays DoD's fuel use within the United States. The figure represents data after the completion of Steps 1 and 2, summarized by fuel type. Table J-1 also reflects the adjustments for JP8 used in land-based equipment, as described above.

Step 3: Omit Land-Based Fuels

Navy and Air Force land-based fuels (i.e., fuel not used by ships or aircraft) were also omitted for the purpose of calculating international bunker fuels. The remaining fuels, listed below, are potential DoD international bunker fuels.

- Marine: naval distillate fuel (F76), marine gas oil (MGO), and intermediate fuel oil (IFO).
- Aviation: jet fuels (JP8, JP5, JP4, JAA, JA1, and JAB).

¹ DoD Directive 4140.43, Fuel Standardization, 1998; DoD Directive 4140.25, DoD Management Policy for Energy Commodities and Related Services, 1999.

² NATO Standard Agreement NATO STANAG 4362, Fuels for Future Ground Equipments Using Compression Ignition or Turbine Engines, 1987.

Step 4: Omit Fuel Transactions Received by Military Services that are not Considered to be International Bunker Fuels

Next, the records were sorted by Military Service. The following assumptions were used regarding bunker fuel use by Service, leaving only the Navy and Air Force as users of military international bunker fuels.

- Only fuel delivered to a ship, aircraft, or installation in the United States can be a potential international bunker fuel. Fuel consumed in international aviation or marine transport should be included in the bunker fuel estimate of the country where the ship or aircraft was fueled. Fuel consumed entirely within a country's borders is not bunker fuel.
- Based on discussions with the Army staff, only an extremely small percentage of Army aviation emissions, and none of its watercraft emissions, qualified as bunker fuel emissions. The magnitude of these emissions was judged to be insignificant when compared to Air Force and Navy emissions. Based on this, Army bunker fuel emissions were assumed to be zero.
- Marine Corps aircraft operating while embarked consume fuel reported as delivered to the Navy. Bunker fuel emissions from embarked Marine Corps aircraft were reported in the Navy bunker fuel estimates. Bunker fuel emissions from other Marine Corps operations and training were assumed to be zero.
- Bunker fuel emissions from other DoD and non-DoD activities (i.e., other federal agencies) that purchase fuel from DESC were assumed to be zero.

Step 5: Determine Bunker Fuel Percentages

Next it was necessary to determine what percent of the marine and aviation fuels were used as international bunker fuels. Military aviation bunkers include international operations (i.e., sorties that originate in the United States and end in a foreign country), operations conducted from naval vessels at sea, and operations conducted from U.S. installations principally over international water in direct support of military operations at sea (e.g., anti-submarine warfare flights). For the Air Force, a bunker fuel weighted average was calculated based on flying hours by major command. International flights were weighted by an adjustment factor to reflect the fact that they typically last longer than domestic flights. In addition, a fuel use correction factor was used to account for the fact that transport aircraft burn more fuel per hour of flight than most tactical aircraft. The Air Force bunker fuel percentage was determined to be 13.2 percent. This percentage was multiplied by total annual Air Force aviation fuel delivered for U.S. activities, producing an estimate for international bunker fuel consumed by the Air Force. The Naval Aviation bunker fuel percentage of total fuel was calculated using flying hour data from *Chief of Naval Operations N88F, Flying Hour Projection System* (N42 1991, 1996, 1999), and estimates of bunker fuel percent of flights provided by the fleet. The Naval Aviation bunker fuel percentage, determined to be 40.4 percent, was multiplied by total annual Navy aviation fuel delivered for U.S. activities, yielding total Navy aviation bunker fuel consumed.

For marine bunkers, fuels consumed while ships are underway are assumed to be bunker fuels. In 2000, the Navy reported that 79 percent of vessel operations were underway, while the remaining 21 percent of operations occurred in port (i.e., pierside). Therefore, the Navy maritime bunker fuel percentage was determined to be 79 percent. The percentage of time underway may vary from year-to-year. For example, for years prior to 2000, the bunker fuel percentage was 87 percent. Table J-2 displays DoD's aviation bunker fuel use and Table J-3 displays DoD's maritime bunker fuel use.

Step 6: Calculate Emissions from Military International Bunker Fuels

Bunker fuel totals were multiplied by appropriate emission factors to determine greenhouse gas emissions (see Table J-4 and Table J-5).

The rows labeled 'U.S. Military' and 'U.S. Military Naval Fuels' within Table 2-39 and Table 2-40 in the Energy Chapter were based on the international bunker fuel totals provided in Table J-2 and Table J-3, below. Total CO₂ emissions from military bunker fuels are presented in Table J-6. Carbon dioxide emissions from aviation bunkers and distillate marine bunkers presented in Table 2-38 are the total of military plus civil aviation and civil marine bunker fuels, respectively. The military component of each total is based on fuels tallied in Table J-2 and Table J-3.

At the completion of the 2000 DoD international bunker fuel estimate, it was apparent that the Navy maritime data provided by DESC were abnormal compared to those data for each year from 1995 to 1999. The Navy fuels and logistics office identified a separate data set, which was used as the source for the 2000 inventory, but Navy continued to investigate the 2000 DESC maritime data, which Navy fuels experts considered an anomaly. DESC determined that a few records in the 2000 maritime data set contained errors that were traced back to the DFAMS database system. The DFAMS program was not originally designed to account for open market bunkers transactions, but was later modified to include these purchases, which resulted in some system complications. For example, there are several places in the program where the fuel quantity must be adjusted to allow for an assumed decimal (i.e., divided by 100). Because the adjustment does not occur automatically in the open market bunkers purchases section of the program, queried quantities would reflect 100 times their actual value. DESC reported that this assumed decimal error would have impacted some of the 2000 data for MGO and F76; however, this error should not be present in previous years' data. DESC ran a new query that produced correction amounts for the 2000 MGO and F-76 fuel data set. This query produced results consistent with data from 1995 to 1999, and the 2001 DoD Inventory has been revised accordingly to reflect the 2000 DESC data.

Table J-1: Transportation Fuels from Domestic Fuel Deliveries^a (Million Gallons)

Vehicle Type/Fuel	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Aviation	4,598.45	4,562.84	3,734.49	3,610.85	3,246.23	3,099.93	2,941.91	2,683.37	2,736.95	2,628.57	2,655.54	2,889.45
Total Jet Fuels	4,598.42	4,562.81	3,734.46	3,610.83	3,246.21	3,099.91	2,941.90	2,683.37	2,736.93	2,628.56	2,655.53	2,889.42
JP8	285.75	283.54	234.46	989.38	1,598.07	2,182.80	2,253.15	2,069.74	2,118.08	2,059.80	2,113.79	2,315.06
JP5	1,025.36	1,017.42	832.71	805.14	723.84	691.22	615.83	552.77	515.56	505.50	472.10	503.17
Other Jet Fuels	3,287.31	3,261.86	2,667.29	1,816.30	924.30	225.89	72.92	60.86	103.29	63.25	69.65	71.19
Aviation Gasoline	0.03	0.03	0.02	0.02	0.02	0.02	0.01	+	0.02	0.01	0.01	0.03
Marine	686.80	632.61	646.18	589.37	478.59	438.91	493.34	639.85	674.22	598.86	454.36	418.45
Middle Distillate (MGO)	+	+	+	+	+	+	38.52	47.48	51.14	49.22	48.29	33.02
Naval Distillate (F76)	686.80	632.61	646.18	589.37	478.59	438.91	448.96	583.41	608.39	542.94	397.97	369.14
Intermediate Fuel Oil (IFO) ^b	+	+	+	+	+	+	5.86	8.95	14.69	6.70	8.09	16.28
Other^c	717.11	590.41	491.68	415.10	356.06	310.95	276.90	265.67	261.28	262.64	257.07	120.89
Diesel	93.04	97.88	102.96	108.31	113.94	119.86	126.09	132.64	139.53	146.78	126.63	26.65
Gasoline	624.07	492.53	388.72	306.78	242.12	191.09	150.81	119.02	93.94	74.14	74.81	24.72
Jet Fuel ^d	+	+	+	+	+	+	+	13.91	27.81	41.72	55.62	69.53
Total (Including Bunkers)	6,002.37	5,785.85	4,872.34	4,615.32	4,080.89	3,849.78	3,712.15	3,588.79	3,672.45	3,490.06	3,366.97	3,428.78

Note: Totals may not sum due to independent rounding.

^a Includes fuel consumption in the United States and U.S. Territories.

^b Intermediate fuel oil (IFO 180 and IFO 380) is a blend of distillate and residual fuels. IFO is used by the Military Sealift Command.

^c Prior to 2001, gasoline and diesel fuel totals were estimated using data provided by the military Services for 1990 and 1996. The 1991 through 1995 data points were interpolated from the Service inventory data. Growth factors used for other diesel and gasoline were 5.2 and -21.1 percent, respectively. The 1997 through 1999 gasoline and diesel fuel data were initially extrapolated from the 1996 inventory data. Data sets for other diesel and gasoline consumed by the military in 2000 were initially estimated based on ground fuels consumption trends. This method produced a result that was more consistent with expected consumption for 2000. In 2001, other gasoline and diesel fuel totals were generated by DESC. Prior estimates for JP8 use from 1997 through 2000 were adjusted to reflect the estimated consumption of JP8 (jet fuel) being used as a replacement for diesel fuel in land-based vehicles and equipment. DoD is increasing its use of JP8 in land-based vehicles and equipment as the Department implements its policy of using a single fuel (JP8) for all tactical equipment. Concurrently, the amount of JP8 reduced in the aviation totals was added to a new JP8 line within the "Other" category of the table. This reallocation of JP8 increases the amount of ground fuel use being reported in the Other category.

^d The fraction of jet fuel consumed in land-based vehicles was estimated using Service data, DESC data, and expert judgment.

+ Does not exceed 0.005 million gallons.

Table J-2: Total U.S. Military Aviation Bunker Fuel (Million Gallons)

Fuel Type/Service	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
JP8	56.74	56.30	46.40	145.33	223.99	300.40	308.81	289.24	300.86	293.04	296.50	327.31
Navy	56.74	56.30	46.08	44.56	40.06	38.25	39.84	44.58	49.14	48.45	44.04	62.10
Air Force	+	+	0.32	100.77	183.93	262.15	268.97	244.66	251.72	244.59	252.46	265.21
JP5	370.53	367.66	300.92	290.95	261.57	249.78	219.40	194.16	184.38	175.37	160.35	169.73
Navy	365.29	362.46	296.66	286.83	257.87	246.25	216.09	191.15	181.36	170.59	155.60	163.68
Air Force	5.25	5.21	4.26	4.12	3.70	3.54	3.31	3.01	3.02	4.77	4.74	6.05
JP4	420.77	417.52	341.40	229.64	113.11	21.50	1.05	0.05	0.03	0.02	0.01	0.02
Navy	0.02	0.02	0.02	0.02	0.01	0.01	+	+	+	+	+	+
Air Force	420.75	417.50	341.39	229.62	113.10	21.49	1.05	0.05	0.03	0.02	0.01	0.02
JAA	13.70	13.60	11.13	10.76	9.67	9.24	10.27	9.42	10.84	10.78	12.46	12.61
Navy	8.45	8.39	6.86	6.64	5.97	5.70	6.58	5.88	6.63	6.32	7.95	8.02
Air Force	5.25	5.21	4.27	4.12	3.71	3.54	3.69	3.54	4.21	4.47	4.51	4.59
JA1	+	+	+	+	+	+	+	+	0.01	+	0.03	0.13
Navy	+	+	+	+	+	+	+	+	+	+	0.02	0.02
Air Force	+	+	+	+	+	+	+	+	0.01	+	0.01	0.11
JAB	+	+	+	+	+	+	+	+	+	+	+	+
Navy	+	+	+	+	+	+	+	+	+	+	+	+
Air Force	+	+	+	+	+	+	+	+	+	+	+	+
Navy Subtotal	430.50	427.17	349.62	338.04	303.91	290.21	262.51	241.61	237.13	225.36	207.61	233.82
Air Force Subtotal	431.25	427.91	350.23	338.63	304.44	290.72	277.02	251.26	258.99	253.85	261.74	275.98
Total	861.75	855.08	699.85	676.68	608.35	580.93	539.53	492.87	496.12	479.21	469.35	509.80

+ Does not exceed 0.005 million gallons.

Note: Totals may not sum due to independent rounding.

Table J-3: Total U.S. DoD Maritime Bunker Fuel (Million Gallons)

Marine Distillates	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Navy - MGO	+	+	+	+	+	+	30.34	35.57	31.88	39.74	23.83	22.50
Navy - F76	522.37	481.15	491.47	448.27	364.01	333.82	331.88	441.65	474.23	465.97	298.61	282.59
Navy - IFO	+	+	+	+	+	+	4.63	7.07	11.61	5.29	6.39	12.87
Total	522.37	481.15	491.47	448.27	364.01	333.82	366.85	484.29	517.72	511.00	328.83	317.96

+ Does not exceed 0.005 million gallons.

Note: Totals may not sum due to independent rounding.

Table J-4: Aviation and Marine Carbon Contents (Tg Carbon/QBtu) and Fraction Oxidized

Mode (Fuel)	Carbon Content Coefficient	Fraction Oxidized
Aviation (Jet Fuel)	variable	0.99
Marine (Distillate)	19.95	0.99
Marine (Residual)	21.49	0.99

Table J-5: Annual Variable Carbon Content Coefficient for Jet Fuel (Tg Carbon/QBtu)

Fuel	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Jet Fuel	19.40	19.40	19.39	19.37	19.35	19.34	19.33	19.33	19.33	19.33	19.33	19.33

Table J-6: Total U.S. DoD CO₂ Emissions from Bunker Fuels (Tg CO₂ Eq.)

Mode	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Aviation	8.2	8.1	6.6	6.4	5.8	5.6	5.2	4.8	4.8	4.6	4.5	4.9
Marine	5.2	4.8	4.9	4.5	3.7	3.4	3.7	4.9	5.2	5.1	3.3	3.2
Total	13.4	12.9	11.6	10.9	9.5	8.9	8.9	9.6	10.0	9.8	7.8	8.1

Note: Totals may not sum due to independent rounding.

ANNEX K

Methodology for Estimating HFC and PFC Emissions from Substitution of Ozone Depleting Substances

The Vintaging Model was developed as a tool for estimating the annual chemical emissions from industrial sectors that have historically used ozone depleting substances (ODSs) in their products. Under the terms of the Montreal Protocol and the Clean Air Act Amendments of 1990, the domestic production of ODSs—chlorofluorocarbons (CFCs), halons, carbon tetrachloride, methyl chloroform, and hydrochlorofluorocarbons (HCFCs)—has been drastically reduced, forcing these industrial sectors to transition to more ozone friendly chemicals. As these industries have moved toward ODSs substitutes such as hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs), the Vintaging Model has evolved into a tool for estimating the rise in consumption and emissions of these alternatives, and the decline of ODS consumption and emissions.

The Vintaging Model estimates emissions from six industrial sectors: refrigeration and air-conditioning, foams, aerosols, solvents, fire extinguishing, and sterilization. Within these sectors, there are over 40 independently modeled end-uses. The model requires information on the market growth for each of the end-uses, as well as a history of the market transition from ODSs to substitutes. As ODSs are phased out, a percentage of the market share originally filled by the ODSs is allocated to each of its substitutes.

The model, named for its method of tracking the emissions of annual “vintages” of new equipment that enter into service, is a “bottom-up” model. It models the consumption of chemicals based on estimates of the quantity of equipment or products sold, serviced, and retired each year, and the amount of the chemical required to manufacture and/or maintain the equipment. The Vintaging Model makes use of this market information to build an inventory of the in-use stocks of the equipment in each of the end-uses. Emissions are estimated by applying annual leak rates, service emission rates, and disposal emission rates to each population of equipment. By aggregating the emission and consumption output from the different end-uses, the model produces estimates of total annual use and emissions of each chemical.

The Vintaging Model synthesizes data from a variety of sources, including data from the ODS Tracking System maintained by the EPA Global Programs Division and information from submissions to EPA under the Significant New Alternatives Policy (SNAP) program. Published sources include documents prepared by the United Nations Environment Programme (UNEP) Technical Options Committees, reports from the Alternative Fluorocarbons Environmental Acceptability Study (AFEAS), and proceedings from the International Conferences on Ozone Protection Technologies and Earth Technologies Forum. EPA also coordinates extensively with numerous trade associations and individual companies. For example, the Alliance for Responsible Atmospheric Policy, the Air-Conditioning and Refrigeration Institute, the Association of Home Appliance Manufacturers, the American Automobile Manufacturers Association, and many of their member companies, have provided valuable information over the years. In some instances the unpublished information that the EPA uses in the model is classified as Confidential Business Information (CBI). The annual emissions inventories of chemicals are aggregated in such a way that CBI cannot be inferred. Full public disclosure of the inputs to the Vintaging Model would jeopardize the security of the CBI that has been entrusted to the EPA.

The following sections discuss the forms of the emission estimating equations used in the Vintaging Model for each broad end-use category. These equations are applied separately for each chemical used within each of approximately 40 different end-uses. In the majority of these end-uses, more than one ODS substitute chemical is used.

In general, the modeled emissions are a function of the amount of chemical consumed in each end-use market. Estimates of the consumption of ODS substitutes can be inferred by extrapolating forward in time from the amount of regulated ODSs used in the early 1990s. Using data gleaned from a variety of sources, assessments are made regarding which alternatives will likely be used, and what fraction of the ODS market in each end-use will be captured by a given alternative. By combining this with estimates of the total end-use market growth, a consumption value can be estimated for each chemical used within each end-use.

Alternatively, “top-down” information on total U.S. consumption of a given chemical is sometimes available. These data can be used by estimating the fraction of this total that is consumed within each end-use. These allocation schemes are guided by EPA’s synthesis of the data available through the aforementioned sources.

Methodology

The methodology used by the Vintaging Model to calculate emissions varies by end-use sector. The methodologies and specific equations used by end-use sector are presented below.

Refrigeration and Air-Conditioning

For refrigeration and air conditioning products, emission calculations are split into two categories: emissions during equipment lifetime, which arise from annual leakage and service losses, and disposal emissions, which occur at the time of discard. Two separate steps are required to calculate the lifetime emissions from leakage and service, and the emissions resulting from disposal of the equipment. These lifetime emissions and disposal emissions are summed to calculate the total emissions from refrigeration and air-conditioning. As new technologies replace older ones, it is generally assumed that there are improvements in their leak, service, and disposal emission rates.

Step 1: Calculate lifetime emissions

Lifetime emissions from any piece of equipment include both the amount of chemical leaked during equipment operation and during service recharges. Emissions from leakage and servicing can be expressed as follows:

$$Es_j = (l_a + l_s) \times \sum Qc_{j-i+1} \quad \text{for } i=1 \rightarrow k$$

Where:

- Es = Emissions from Equipment Serviced. Emissions in year j from normal leakage and servicing (including recharging) of equipment.
- l_a = Annual Leak Rate. Average annual leak rate during normal equipment operation (expressed as a percentage of total chemical charge).
- l_s = Service Leak Rate. Average leakage during equipment servicing (expressed as a percentage of total chemical charge).
- Qc = Quantity of Chemical in New Equipment. Total amount of a specific chemical used to charge new equipment in a given year, j , by weight.
- K = Lifetime. The average lifetime of the equipment.

Step 2: Calculate disposal emissions

The disposal emission equations assume that a certain percentage of the chemical charge will be emitted to the atmosphere when that vintage is discarded. Disposal emissions are thus a function of the quantity of chemical contained in the retiring equipment fleet and the proportion of chemical released at disposal:

$$Ed_j = Qc_{j-k+1} \times [1 - (rm \times rc)]$$

Where:

- Ed = Emissions from Equipment Disposed. Emissions in year j from the disposal of equipment.
- Qc = Quantity of Chemical in New Equipment. Total amount of a specific chemical used to charge new equipment in a given year, j , by weight.
- rm = Chemical Remaining. Amount of chemical remaining in equipment at the time of disposal (expressed as a percentage of total chemical charge)

- rc = Chemical Recovery Rate. Amount of chemical that is recovered just prior to disposal (expressed as a percentage of chemical remaining at disposal (rm))
- k = Lifetime. The average lifetime of the equipment.

Step 3: Calculate total emissions

Finally, lifetime and disposal emissions are summed to provide an estimate of total emissions.

$$E_j = Es_j + Ed_j$$

Where:

- E = Total Emissions. Emissions from refrigeration and air conditioning equipment in year j .
- Es = Emissions from Equipment Serviced. Emissions in year j from normal leakage and servicing (recharging) of equipment.
- Ed = Emissions from Equipment Disposed. Emissions in year j from the disposal of equipment.

Aerosols

All HFCs and PFCs used in aerosols are assumed to be emitted in the year of manufacture. Since there is currently no aerosol recycling, it is assumed that all of the annual production of aerosol propellants is released to the atmosphere. The following equation describes the emissions from the aerosols sector.

$$E_j = Qc_j$$

Where:

- E = Emissions. Total emissions of a specific chemical in year j from use in aerosol products, by weight.
- Qc = Quantity of Chemical. Total quantity of a specific chemical contained in aerosol products sold in year j , by weight.

Solvents

Generally, most solvents are assumed to remain in the liquid phase and are not emitted as gas. Thus, emissions are considered “incomplete,” and are a fixed percentage of the amount of solvent consumed in a year. The remainder of the consumed solvent is assumed to be reused or disposed without being released to the atmosphere. The following equation calculates emissions from solvent applications.

$$E_j = l \times Qc_j$$

Where:

- E = Emissions. Total emissions of a specific chemical in year j from use in solvent applications, by weight.
- l = Percent Leakage. The percentage of the total chemical that is leaked to the atmosphere.
- Qc = Quantity of Chemical. Total quantity of a specific chemical sold for use in solvent applications in the year j , by weight.

Fire Extinguishing

Total emissions from fire extinguishing are assumed, in aggregate, to equal a percentage of the total quantity of chemical in operation at a given time. For modeling purposes, it is assumed that fire extinguishing equipment leaks at a constant rate for an average equipment lifetime. This percentage varies for streaming and flooding equipment.

Step 1: Calculate emissions from streaming equipment

$$E_j = l_{se} \times \sum Qc_{j-i+1} \quad \text{for } i=1 \rightarrow k$$

Where:

- E = Emissions. Total emissions of a specific chemical in year j for streaming fire extinguishing equipment, by weight.
- l_{se} = Percent Leakage from Streaming Equipment. The percentage of the total chemical in operation that is leaked to the atmosphere.
- Qc = Quantity of Chemical from streaming equipment. Total amount of a specific chemical used in new streaming fire extinguishing equipment in a given year, j , by weight.
- k = Lifetime. The average lifetime of the equipment.

Step 2: Calculate emissions from flooding equipment

$$E_j = l_{fe} \times \sum Qc_{j-i+1} \quad \text{for } i=1 \rightarrow k$$

Where:

- E = Emissions. Total emissions of a specific chemical in year j for flooding fire extinguishing equipment, by weight.
- l_{fe} = Percent Leakage from Flooding Equipment. The percentage of the total chemical in operation that is leaked to the atmosphere.
- Qc = Quantity of Chemical from flooding equipment. Total amount of a specific chemical used in new flooding fire extinguishing equipment in a given year, j , by weight.
- k = Lifetime. The average lifetime of the equipment.

Foam Blowing

Foams are given emission profiles depending on the foam type (open cell or closed cell). Open cell foams are assumed to be 100 percent emissive in the year of manufacture. Closed cell foams are assumed to emit a portion of their total HFC or PFC content upon manufacture, a portion at a constant rate over the lifetime of the foam, and a portion at disposal.

Step 1: Calculate emissions from open-cell foam

Emissions from open-cell foams are calculated using the following equation.

$$E_j = Qc_j$$

Where:

- E = Emissions. Total emissions of a specific chemical in year j used for open-cell foam blowing, by weight.
- Qc = Quantity of Chemical. Total amount of a specific chemical used for open-cell foam blowing in year j , by weight.

Step 2: Calculate emissions from closed-cell foam

Emissions from closed-cell foams are calculated using the following equation.

$$E_j = \sum (ef_i \times Qc_{j-i+1}) \quad \text{for } i=1 \rightarrow k$$

Where:

E = Emissions. Total emissions of a specific chemical in year j for closed-cell foam blowing, by weight.

ef = Emission Factor. Percent of foam's original charge emitted in each year ($1 \rightarrow k$). This emission factor is generally variable, including a rate for manufacturing emissions (occurs in the first year of foam life), annual emissions (every year throughout the foam lifetime), and disposal emissions (occurs during the final year of foam life).

Qc = Quantity of Chemical. Total amount of a specific chemical used in closed-cell foams in year j .

k = Lifetime. Average lifetime of foam product.

Sterilization

For sterilization applications, all chemicals that are used in the equipment in any given year are assumed to be emitted in that year, as shown in the following equation.

$$E_j = Qc_j$$

Where:

E = Emissions. Total emissions of a specific chemical in year j from use in sterilization equipment, by weight.

Qc = Quantity of Chemical. Total quantity of a specific chemical used in sterilization equipment in year j , by weight.

Model Output

By repeating these calculations for each year, the Vintaging Model creates annual profiles of use and emissions for ODS and ODS substitutes. The results can be shown for each year in two ways: 1) on a chemical-by-chemical basis, summed across the end-uses, or 2) on an end-use basis. Values for use and emissions are calculated both in metric tons and in teragrams of carbon dioxide equivalents (Tg CO₂ Eq.). The conversion of metric tons of chemical to Tg CO₂ Eq. is accomplished through a linear scaling of tonnage by the global warming potential (GWP) of each chemical.

Throughout its development, the Vintaging Model has undergone annual modifications. As new or more accurate information becomes available, the model is adjusted in such a way that both past and future emission estimates are often altered.

