Annexes to the Inventory of U.S. GHG Emissions and Sinks

The following seven annexes provide additional information related to the material presented in the main body of this report as directed in the *UNFCCC Guidelines on Reporting and Review* (GE.03-60887). Annex 1 contains an analysis of the key categories of emissions discussed in this report and a review of the methodology used to identify those key categories. Annex 2 describes the methodologies used to estimate CO_2 emissions from fossil fuel combustion, the carbon content of fossil fuels, and the amount of carbon stored in products from non-energy uses of fossil fuels. Annex 3 discusses the methodologies used for a number of individual source categories in greater detail than was presented in the main body of the report and includes explicit activity data and emission factor tables. Annex 4 presents the IPCC reference approach for estimating CO_2 emissions from fossil fuel combustion. Annex 5 addresses the criteria for the inclusion of an emission source category and discusses some of the sources that are excluded from U.S. estimates. Annex 6 provides a range of additional information that is relevant to the contents of this report. Annex 7 provides data on the uncertainty of the emission estimates included in this report. Finally, Annex 8 provides information on the QA/QC methods and procedures used in the development of the Inventory.

ANNEX 1 Key Category Analysis

The United States has identified national key categories based on the estimates presented in this report. The IPCC's *Good Practice Guidance* (IPCC 2000) describes a key category as a "[category] that is prioritized within the national inventory system because its estimate has a significant influence on a country's total inventory of direct greenhouse gases in terms of the absolute level of emissions, the trend in emissions, or both." By definition, key categories are sources or sinks that have the greatest contribution to the absolute overall level of national emissions in any of the years covered by the time series. In addition, when an entire time series of emission estimates is prepared, a determination of key categories must also account for the influence of the trends of individual categories. Therefore, a trend assessment is conducted to identify source and sink categories for which significant uncertainty in the estimate would have considerable effects on overall emission trends. Finally, a qualitative evaluation of key categories should be performed, in order to capture any key categories that were not identified in either of the quantitative analyses, but can be considered key because of the unique country-specific estimation methods.

The methodology for conducting a key category analysis, as defined by IPCC's *Good Practice Guidance* (IPCC 2000), IPCC's *Good Practice Guidance for Land Use, Land-Use Change, and Forestry (IPCC 2003)*, and IPCC's *2006 Guidelines for National Greenhouse Gas Inventories* IPCC (2006); includes:

- Tier 1 approach (including both level and trend assessments);
- Tier 2 approach (including both level and trend assessments, and incorporating uncertainty analysis); and
- Qualitative approach.

This Annex presents an analysis of key categories, both for sources only and also for sources and sinks (i.e., including LULUCF); discusses Tier 1, Tier 2, and qualitative approaches to identifying key categories; provides level and trend assessment equations; and provides a brief statistical evaluation of IPCC's quantitative methodologies for defining key categories. Table A- 1 presents the key categories for the United States (including and excluding LULUCF categories) using emissions and uncertainty data in this report, and ranked according to their sector and global warming potential-weighted emissions in 2012. The table also indicates the criteria used in identifying these categories (i.e., level, trend, Tier 1, Tier 2, and/or qualitative assessments).

Table A- 1: Key Source Categories for the United States (1990-2012)

IPCC Source Categories	Gas	Tier 1				Tier 2				Qual	2012 Emissions
		Level Without LULUCF	Trend Without LULUCF	Level With LULUCF	Trend With LULUCF	Level Without LULUCF	Trend Without LULUCF	Level With LULUCF	Trend With LULUCF		(Tg CO_2 Eq.)
Energy											
CO_2 Emissions from Stationary Combustion - Coal - Electricity Generation	CO_2	•	•	•	•	•	•	•	•		1,511.2
CO_2 Emissions from Mobile Combustion: Road	CO_2	•	•	•	•	•	•	•	•		1,469.8
CO_2 Emissions from Stationary Combustion - Gas - Electricity Generation	CO_2	•	•	•	•	•	•	•	•		492.2
CO_2 Emissions from Stationary Combustion - Gas - Industrial	CO_2	•	•	•		•		•			434.7
CO_2 Emissions from Stationary Combustion - Oil - Industrial	CO_2	•	•	•	•	•	•	•	•		265.2
CO_2 Emissions from Stationary Combustion - Gas - Residential	CO_2	•	•	•	•	•		•			224.8
CO_2 Emissions from Stationary Combustion - Gas - Commercial	CO_2	•	•	•	•	•		•			156.9
CO_2 Emissions from Mobile Combustion: Aviation	CO_2	•	•	•	•	•	•	•	•		145.1
CO_2 Emissions from Non-Energy Use of Fuels	CO_2	•	•	•	•	•	•	•	•		110.3
CO_2 Emissions from Mobile Combustion: Other	CO_2	•	•	•	•						84.5
CO_2 Emissions from Stationary Combustion - Coal - Industrial	CO_2	•	•	•	•	•	•	•	•		74.3
CO_2 Emissions from Stationary Combustion - Oil - Residential	CO_2	•	•	•	•		•				64.1
CO_2 Emissions from Stationary Combustion - Oil - U.S. Territories	CO_2	•	•	•	•						44.7
CO_2 Emissions from Mobile Combustion: Marine	CO_2	•	•	•	•						40.1
CO_2 Emissions from Stationary Combustion - Oil – Commercial	CO_2	•	•	•	•						36.4
CO_2 Emissions from Natural Gas Systems	CO_2	•		•		•		•			35.2
CO_2 Emissions from Stationary Combustion - Oil - Electricity Generation	CO_2	•	•	•	•		•		•		18.8
CO_2 Emissions from Stationary Combustion - Coal – Commercial	CO_2		•		•						4.1
CO_2 Emissions from Stationary Combustion - Coal – Residential	CO_2						•				0.0
CH_4 Emissions from Natural Gas Systems	CH_4	•	•	•	•	•	•	•	•		129.9
Fugitive Emissions from Coal Mining	CH_4	•	•	•	•	•	•	•	•		55.8
CH_4 Emissions from Petroleum Systems	CH_4	•		•	•	•	•	•	•		31.7
Non-CO_2 Emissions from Stationary Combustion - Residential	CH_4					•	•	•	•		3.1
Non-CO_2 Emissions from Stationary Combustion - Electricity Generation	N_2O		•		•	•	•	•	•		18.3
N_2O Emissions from Mobile Combustion: Road	N_2O	•	•	•	•	•	•	•	•		12.6

Non-CO_2 Emissions from Stationary Combustion - Industrial	N_2O	•					•				
International Bunker Fuels[c]	Several									•	112.8
Industrial Processes											
CO_2 Emissions from Iron and Steel Production & Metallurgical Coke Production	CO_2	•	•	•	•	•	•	•	•		54.3
CO_2 Emissions from Cement Production	CO_2	•		•							35.1
N_2O Emissions from Adipic Acid Production	N_2O		•		•						5.8
Emissions from Substitutes for Ozone Depleting Substances	HiGWP	•	•	•	•	•	•	•	•		146.8
SF_6 Emissions from Electrical Transmission and Distribution	HiGWP	•	•	•	•		•				6.0
HFC-23 Emissions from HCFC-22 Production	HiGWP		•		•		•		•		4.3
PFC Emissions from Aluminum Production	HiGWP		•		•						2.5
Agriculture											
CH_4 Emissions from Enteric Fermentation	CH_4	•		•		•		•			141.0
CH_4 Emissions from Manure Management	CH_4	•	•	•	•	•	•	•	•		52.9
Direct N_2O Emissions from Agricultural Soil Management	N_2O	•	•	•	•	•	•	•			260.9
Indirect N_2O Emissions from Applied Nitrogen	N_2O	•		•		•	•	•			45.7
Waste											
CH_4 Emissions from Landfills	CH_4	•	•	•	•	•	•	•	•		102.8
Land Use, Land Use Change, and Forestry											
CO_2 Emissions from Land Converted to Cropland	CO_2				•			•	•		16.8
CO_2 Emissions from Grassland Remaining Grassland	CO_2							•	•		6.7
CO_2 Emissions from Landfilled Yard Trimmings and Food Scraps	CO_2				•			•	•		(13.2)
CO_2 Emissions from Cropland Remaining Cropland	CO_2			•	•			•	•		(26.5)
CO_2 Emissions from Urban Trees	CO_2			•	•			•	•		(88.4)
CO_2 Emissions from Changes in Forest Carbon Stocks	CO_2			•	•			•	•		(866.5)
CH_4 Emissions from Forest Fires	CH_4				•			•	•		15.3
N_2O Emissions from Forest Fires	N_2O				•			•	•		12.5
Subtotal Without LULUCF											**6,324.6**
Total Emissions Without LULUCF											**6,487.8**
Percent of Total Without LULUCF											**97%**
Subtotal With LULUCF											**5,379.1**
Total Emissions With LULUCF											**5,546.3**
Percent of Total With LULUCF											**97%**

[a] Qualitative criteria.

[b] Emissions from this source not included in totals.

Note: Parentheses indicate negative values (or sequestration). Table A- 2 provides a complete listing of source categories by IPCC sector, along with notations on the criteria used in identifying key categories, without LULUCF sources and sinks. Similarly, Table A- 3 provides a complete listing of source and sink categories by IPCC sector, along with notations on the criteria used in identifying key categories, including LULUCF sources and sinks. The notations refer specifically to the year(s) in the inventory time series (i.e., 1990 to 2012) in which each source category reached the threshold for being a key category based on either a Tier 1 or Tier 2 level assessment.

In addition to conducting Tier 1 and 2 level and trend assessments, a qualitative assessment of the source categories, as described in the IPCC's *Good Practice Guidance* (IPCC 2000), was conducted to capture any key categories that were not identified by any quantitative method. One additional key category, international bunker fuels, was identified using this qualitative assessment. International bunker fuels are fuels consumed for aviation or marine international transport activities, and emissions from these fuels are reported separately from totals in accordance with IPCC guidelines. If these emissions were included in the totals, bunker fuels would qualify as a key category according to the Tier 1 approach. The amount of uncertainty associated with estimation of emissions from international bunker fuels also supports the qualification of this source category as key, which would qualify it as a key category according to the Tier 2 approach.

Table A- 2: U.S Greenhouse Gas Inventory Source Categories without LULUCF

IPCC Source Categories	Direct GHG	2012 Emissions (Tg CO_2 Eq.)	Key Category?	ID Criteria[a]	Level in which year(s)?[b]
Energy					
CO_2 Emissions from Stationary Combustion - Coal - Electricity Generation	CO_2	1,511.2	•	L_1 T_1 L_2 T_2	1990, 2012
CO_2 Emissions from Mobile Combustion: Road	CO_2	1,469.8	•	L_1 T_1 L_2 T_2	1990, 2012
CO_2 Emissions from Stationary Combustion - Gas - Electricity Generation	CO_2	492.2	•	L_1 T_1 L_2 T_2	1990, 2012
CO_2 Emissions from Stationary Combustion - Gas - Industrial	CO_2	434.7	•	L_1 T_1 L_2	1990, 2012
CO_2 Emissions from Stationary Combustion - Oil - Industrial	CO_2	265.2	•	L_1 T_1 L_2 T_2	1990, 2012
CO_2 Emissions from Stationary Combustion - Gas - Residential	CO_2	224.8	•	L_1 T_1 L_2	1990, 2012
CO_2 Emissions from Stationary Combustion - Gas - Commercial	CO_2	156.9	•	L_1 T_1 L_2	1990, 2012
CO_2 Emissions from Mobile Combustion: Aviation	CO_2	145.1	•	L_1 T_1 L_2 T_2	1990, 2012
CO_2 Emissions from Non-Energy Use of Fuels	CO_2	110.3	•	L_1 T_1 L_2 T_2	1990, 2012
CO_2 Emissions from Mobile Combustion: Other	CO_2	84.5	•	L_1 T_1	1990_1, 2012_1
CO_2 Emissions from Stationary Combustion - Coal - Industrial	CO_2	74.3	•	L_1 T_1 L_2 T_2	1990, 2012
CO_2 Emissions from Stationary Combustion - Oil - Residential	CO_2	64.1	•	L_1 T_1 T_2	1990_1, 2012_1
CO_2 Emissions from Stationary Combustion - Oil - U.S. Territories	CO_2	44.7	•	L_1 T_1	2012_1
CO_2 Emissions from Mobile Combustion: Marine	CO_2	40.1	•	L_1 T_1	1990_1, 2012_1
CO_2 Emissions from Stationary Combustion - Oil - Commercial	CO_2	36.4	•	L_1 T_1	1990_1, 2012_1
CO_2 Emissions from Natural Gas Systems	CO_2	35.2	•	L_1 L_2	1990, 2012
CO_2 Emissions from Stationary Combustion - Oil - Electricity Generation	CO_2	18.8	•	L_1 T_1 T_2	1990_1
CO_2 Emissions from Incineration of Waste	CO_2	12.2			
CO_2 Emissions from Stationary Combustion - Coal - Commercial	CO_2	4.1	•	T_1	
CO_2 Emissions from Stationary Combustion - Coal - U.S. Territories	CO_2	3.4			
CO_2 Emissions from Stationary Combustion - Gas - U.S. Territories	CO_2	1.4			
CO_2 Emissions from Petroleum Systems	CO_2	0.4			
CO_2 Emissions from Stationary Combustion - Geothermal Energy	CO_2	0.4			
CO_2 Emissions from Stationary Combustion - Coal - Residential	CO_2	0.0	•	T_2	
CH_4 Emissions from Natural Gas Systems	CH_4	129.9	•	L_1 T_1 L_2 T_2	1990, 2012
Fugitive Emissions from Coal Mining	CH_4	55.8	•	L_1 T_1 L_2 T_2	1990, 2012
CH_4 Emissions from Petroleum Systems	CH_4	31.7	•	L_1 L_2 T_2	1990, 2012_2
Fugitive Emissions from Abandoned Underground Coal Mines	CH_4	4.7			
Non-CO_2 Emissions from Stationary Combustion - Residential	CH_4	3.1	•	L_2 T_2	1990_2
Non-CO_2 Emissions from Stationary Combustion - Industrial	CH_4	1.2			
CH_4 Emissions from Mobile Combustion: Road	CH_4	1.2			
Non-CO_2 Emissions from Stationary Combustion - Commercial	CH_4	0.8			

Non-CO_2 Emissions from Stationary Combustion - Electricity Generation	CH_4	0.5			
CH_4 Emissions from Mobile Combustion: Other	CH_4	0.4			
Non-CO_2 Emissions from Stationary Combustion - U.S. Territories	CH_4	0.1			
CH_4 Emissions from Mobile Combustion: Aviation	CH_4	+			
CH_4 Emissions from Mobile Combustion: Marine	CH_4	+			
CH_4 Emissions from Incineration of Waste	CH_4	+			
Non-CO_2 Emissions from Stationary Combustion - Electricity Generation	N_2O	18.3	•	T_1 L_2 T_2	1990_2, 2012_2
N_2O Emissions from Mobile Combustion: Road	N_2O	12.6	•	L_1 T_1 L_2 T_2	1990
Non-CO_2 Emissions from Stationary Combustion - Industrial	N_2O	2.5	•	T_2	
N_2O Emissions from Mobile Combustion: Other	N_2O	2.0			
N_2O Emissions from Mobile Combustion: Aviation	N_2O	1.4			
Non-CO_2 Emissions from Stationary Combustion - Residential	N_2O	0.8			
N_2O Emissions from Mobile Combustion: Marine	N_2O	0.6			
N_2O Emissions from Incineration of Waste	N_2O	0.4			
Non-CO_2 Emissions from Stationary Combustion - Commercial	N_2O	0.3			
Non-CO_2 Emissions from Stationary Combustion - U.S. Territories	N_2O	0.1			
International Bunker Fuels[c]	Several	112.8	•	Q	
Industrial Processes					
CO_2 Emissions from Iron and Steel Production & Metallurgical Coke Production	CO_2	54.3	•	L_1 T_1 L_2 T_2	1990, 2012_1
CO_2 Emissions from Cement Production	CO_2	35.1	•	L_1	1990_1
CO_2 Emissions from Lime Production	CO_2	13.3			
CO_2 Emissions from Ammonia Production	CO_2	9.4			
CO_2 Emissions from Other Process Uses of Carbonates	CO_2	8.0			
CO_2 Emissions from Urea Consumption for Non-Ag Purposes	CO_2	5.2			
CO_2 Emissions from Petrochemical Production	CO_2	3.5			
CO_2 Emissions from Aluminum Production	CO_2	3.4			
CO_2 Emissions from Soda Ash Production and Consumption	CO_2	2.7			
CO_2 Emissions from Carbon Dioxide Consumption	CO_2	1.8			
CO_2 Emissions from Titanium Dioxide Production	CO_2	1.7			
CO_2 Emissions from Ferroalloy Production	CO_2	1.7			
CO_2 Emissions from Zinc Production	CO_2	1.4			
CO_2 Emissions from Glass Production	CO_2	1.2			
CO_2 Emissions from Phosphoric Acid Production	CO_2	1.1			
CO_2 Emissions from Lead Production	CO_2	0.5			
CO_2 Emissions from Silicon Carbide Production and Consumption	CO_2	0.2			
CH_4 Emissions from Petrochemical Production	CH_4	3.1			
CH_4 Emissions from Iron and Steel Production & Metallurgical Coke Production	CH_4	0.6			
CH_4 Emissions from Ferroalloy Production	CH_4	+			
CH_4 Emissions from Silicon Carbide Production and Consumption	CH_4	+			
N_2O Emissions from Nitric Acid Production	N_2O	15.3			
N_2O Emissions from Adipic Acid Production	N_2O	5.8	•	T_1	
N_2O Emissions from Product Uses	N_2O	4.4			
Emissions from Substitutes for Ozone Depleting Substances	HiGWP	146.8	•	L_1 T_1 L_2 T_2	2012
SF_6 Emissions from Electrical Transmission and Distribution	HiGWP	6.0	•	T_1 T_2	
HFC-23 Emissions from HCFC-22 Production	HiGWP	4.3	•	L_1 T_1 T_2	1990_1
PFC, HFC, and SF_6 Emissions from Semiconductor Manufacture	HiGWP	3.7			
PFC Emissions from Aluminum Production	HiGWP	2.5	•	T_1	
SF_6 Emissions from Magnesium Production and Processing	HiGWP	1.7			
Agriculture					
CH_4 Emissions from Enteric Fermentation	CH_4	141.0	•	L_1 L_2	1990, 2012

CH_4 Emissions from Manure Management	CH_4	52.9	•	L_1 T_1 L_2 T_2	2012
CH_4 Emissions from Rice Cultivation	CH_4	7.4			
CH_4 Emissions from Field Burning of Agricultural Residues	CH_4	0.3			
Direct N_2O Emissions from Agricultural Soil Management	N_2O	260.9	•	L_1 T_1 L_2 T_2	1990, 2012
Indirect N_2O Emissions from Applied Nitrogen	N_2O	45.7	•	L_1 L_2 T_2	1990, 2012
N_2O Emissions from Manure Management	N_2O	18.0			
N_2O Emissions from Field Burning of Agricultural Residues	N_2O	0.1			
Waste					
CH_4 Emissions from Landfills	CH_4	102.8	•	L_1 T_1 L_2 T_2	1990, 2012
CH_4 Emissions from Wastewater Treatment	CH_4	12.8			
CH_4 Emissions from Composting	CH_4	1.6			
N_2O Emissions from Wastewater Treatment	N_2O	5.0			
N_2O Emissions from Composting	N_2O	1.8			

[a] For the ID criteria, L refers to a key category identified through a level assessment; T refers to a key category identified through a trend assessment and the subscripted number refers to either a Tier 1 or Tier 2 assessment (e.g., L_2 designates a source is a key category for a Tier 2 level assessment).

[b] If the source is a key category for both L_1 and L_2 (as designated in the ID criteria column), it is a key category for both assessments in the years provided unless noted by a subscript, in which case it is a key category for that assessment in that year only (.e.g., 1990 designates a source is a key category for the Tier 2 assessment only in 1990).

[c] Emissions from these sources not included in totals.

+ Does not exceed 0.05 Tg CO_2 Eq.

Note: LULUCF sources and sinks are not included in this analysis.

Table A- 3: U.S Greenhouse Gas Inventory Source Categories with LULUCF

IPCC Source Categories	Direct GHG	2012 Emissions (Tg CO_2 Eq.)	Key Category?	ID Criteria[a]	Level in which year(s)?[b]
Energy					
CO_2 Emissions from Stationary Combustion - Coal - Electricity Generation	CO_2	1,511.2	•	L_1 T_1 L_2 T_2	1990, 2012
CO_2 Emissions from Mobile Combustion: Road	CO_2	1,469.8	•	L_1 T_1 L_2 T_2	1990, 2012
CO_2 Emissions from Stationary Combustion - Gas - Electricity Generation	CO_2	492.2	•	L_1 T_1 L_2 T_2	1990_1, 2012
CO_2 Emissions from Stationary Combustion - Gas - Industrial	CO_2	434.7	•	L_1 L_2	1990, 2012
CO_2 Emissions from Stationary Combustion - Oil - Industrial	CO_2	265.2	•	L_1 T_1 L_2 T_2	1990, 2012
CO_2 Emissions from Stationary Combustion - Gas - Residential	CO_2	224.8	•	L_1 T_1 L_2	1990, 2012
CO_2 Emissions from Stationary Combustion - Gas - Commercial	CO_2	156.9	•	L_1 T_1 L_2	1990, 2012
CO_2 Emissions from Mobile Combustion: Aviation	CO_2	145.1	•	L_1 T_1 L_2 T_2	1990, 2012_1
CO_2 Emissions from Non-Energy Use of Fuels	CO_2	110.3	•	L_1 T_1 L_2 T_2	1990, 2012
CO_2 Emissions from Mobile Combustion: Other	CO_2	84.5	•	L_1 T_1	1990_1, 2012_1
CO_2 Emissions from Stationary Combustion - Coal - Industrial	CO_2	74.3	•	L_1 T_1 L_2 T_2	1990, 2012
CO_2 Emissions from Stationary Combustion - Oil - Residential	CO_2	64.1	•	L_1 T_1	1990_1, 2012_1
CO_2 Emissions from Stationary Combustion - Oil - U.S. Territories	CO_2	44.7	•	L_1 T_1	1990_1, 2012_1
CO_2 Emissions from Mobile Combustion: Marine	CO_2	40.1	•	L_1 T_1	1990_1, 2012_1
CO_2 Emissions from Stationary Combustion - Oil - Commercial	CO_2	36.4	•	L_1 T_1	1990_1, 2012_1
CO_2 Emissions from Natural Gas Systems	CO_2	35.2	•	L_1 L_2	1990, 2012
CO_2 Emissions from Stationary Combustion - Oil - Electricity Generation	CO_2	18.8	•	L_1 T_1 T_2	1990_1
CO_2 Emissions from Incineration of Waste	CO_2	12.2			
CO_2 Emissions from Stationary Combustion - Coal - Commercial	CO_2	4.1	•	T_1	
CO_2 Emissions from Stationary Combustion - Coal - U.S. Territories	CO_2	3.4			
CO_2 Emissions from Stationary Combustion - Gas - U.S. Territories	CO_2	1.4			
CO_2 Emissions from Petroleum Systems	CO_2	0.4			
CO_2 Emissions from Stationary Combustion - Geothermal Energy	CO_2	0.4			
CO_2 Emissions from Stationary Combustion - Coal - Residential	CO_2	0.0			
CH_4 Emissions from Natural Gas Systems	CH_4	129.9	•	L_1 T_1 L_2 T_2	1990, 2012
Fugitive Emissions from Coal Mining	CH_4	55.8	•	L_1 T_1 L_2 T_2	1990, 2012
CH_4 Emissions from Petroleum Systems	CH_4	31.7	•	L_1 T_1 L_2 T_2	1990, 2012
Fugitive Emissions from Abandoned Underground Coal Mines	CH_4	4.7			
Non-CO_2 Emissions from Stationary Combustion - Residential	CH_4	3.1	•	L_2 T_2	1990_2
Non-CO_2 Emissions from Stationary Combustion - Industrial	CH_4	1.2			
CH_4 Emissions from Mobile Combustion: Road	CH_4	1.2			
Non-CO_2 Emissions from Stationary Combustion - Commercial	CH_4	0.8			
Non-CO_2 Emissions from Stationary Combustion - Electricity Generation	CH_4	0.5			
CH_4 Emissions from Mobile Combustion: Other	CH_4	0.4			
Non-CO_2 Emissions from Stationary Combustion - U.S. Territories	CH_4	0.1			
CH_4 Emissions from Mobile Combustion: Aviation	CH_4	+			
CH_4 Emissions from Mobile Combustion: Marine	CH_4	+			
CH_4 Emissions from Incineration of Waste	CH_4	+			
Non-CO_2 Emissions from Stationary Combustion - Electricity Generation	N_2O	18.3	•	T_1 L_2 T_2	1990_2, 2012_2
N_2O Emissions from Mobile Combustion: Road	N_2O	12.6	•	L_1 T_1 L_2 T_2	1990

Non-CO_2 Emissions from Stationary Combustion - Industrial	N_2O	2.5			
N_2O Emissions from Mobile Combustion: Other	N_2O	2.0			
N_2O Emissions from Mobile Combustion: Aviation	N_2O	1.4			
Non-CO_2 Emissions from Stationary Combustion - Residential	N_2O	0.8			
N_2O Emissions from Mobile Combustion: Marine	N_2O	0.6			
N_2O Emissions from Incineration of Waste	N_2O	0.4			
Non-CO_2 Emissions from Stationary Combustion - Commercial	N_2O	0.3			
Non-CO_2 Emissions from Stationary Combustion - U.S. Territories	N_2O	0.1			
International Bunker Fuels[c]	Several	112.8	•	Q	
Industrial Processes					
CO_2 Emissions from Iron and Steel Production & Metallurgical Coke Production	CO_2	54.3	•	L_1 T_1 L_2 T_2	1990, 2012_1
CO_2 Emissions from Cement Production	CO_2	35.1	•	L_1	1990_1, 2012_1
CO_2 Emissions from Lime Production	CO_2	13.3			
CO_2 Emissions from Ammonia Production	CO_2	9.4			
CO_2 Emissions from Other Process Uses of Carbonates	CO_2	8.0			
CO_2 Emissions from Urea Consumption for Non-Ag Purposes	CO_2	5.2			
CO_2 Emissions from Petrochemical Production	CO_2	3.5			
CO_2 Emissions from Aluminum Production	CO_2	3.4			
CO_2 Emissions from Soda Ash Production and Consumption	CO_2	2.7			
CO_2 Emissions from Carbon Dioxide Consumption	CO_2	1.8			
CO_2 Emissions from Titanium Dioxide Production	CO_2	1.7			
CO_2 Emissions from Ferroalloy Production	CO_2	1.7			
CO_2 Emissions from Zinc Production	CO_2	1.4			
CO_2 Emissions from Glass Production	CO_2	1.2			
CO_2 Emissions from Phosphoric Acid Production	CO_2	1.1			
CO_2 Emissions from Lead Production	CO_2	0.5			
CO_2 Emissions from Silicon Carbide Production and Consumption	CO_2	0.2			
CH_4 Emissions from Petrochemical Production	CH_4	3.1			
CH_4 Emissions from Iron and Steel Production & Metallurgical Coke Production	CH_4	0.6			
CH_4 Emissions from Ferroalloy Production	CH_4	+			
CH_4 Emissions from Silicon Carbide Production and Consumption	CH_4	+			
N_2O Emissions from Nitric Acid Production	N_2O	15.3			
N_2O Emissions from Adipic Acid Production	N_2O	5.8	•	T_1	
N_2O Emissions from Product Uses	N_2O	4.4			
Emissions from Substitutes for Ozone Depleting Substances	HiGWP	146.8	•	L_1 T_1 L_2 T_2	2012
SF_6 Emissions from Electrical Transmission and Distribution	HiGWP	6.0	•	T_1 T_2	
HFC-23 Emissions from HCFC-22 Production	HiGWP	4.3	•	L_1 T_1	1990_1
PFC, HFC, and SF_6 Emissions from Semiconductor Manufacture	HiGWP	3.7			
PFC Emissions from Aluminum Production	HiGWP	2.5	•	T_1	
SF_6 Emissions from Magnesium Production and Processing	HiGWP	1.7			
Agriculture					
CH_4 Emissions from Enteric Fermentation	CH_4	141.0	•	L_1 L_2	1990, 2012
CH_4 Emissions from Manure Management	CH_4	52.9	•	L_1 T_1 L_2 T_2	1990_1, 2012
CH_4 Emissions from Rice Cultivation	CH_4	7.4			
CH_4 Emissions from Field Burning of Agricultural Residues	CH_4	0.3			
Direct N_2O Emissions from Agricultural Soil Management	N_2O	260.9	•	L_1 L_2	1990, 2012
Indirect N_2O Emissions from Applied Nitrogen	N_2O	45.7	•	L_1 L_2	1990, 2012
N_2O Emissions from Manure Management	N_2O	18.0			
N_2O Emissions from Field Burning of Agricultural Residues	N_2O	0.1			
Waste					

CH_4 Emissions from Landfills	CH_4	102.8	•	L_1 T_1 L_2 T_2	1990, 2012
CH_4 Emissions from Wastewater Treatment	CH_4	12.8			
CH_4 Emissions from Composting	CH_4	1.6			
N_2O Emissions from Wastewater Treatment	N_2O	5.0			
N_2O Emissions from Composting	N_2O	1.8			
Land Use, Land Use Change, and Forestry					
CO_2 Emissions from Land Converted to Cropland	CO_2	16.8	•	T_1 L_2 T_2	1990, 2012
CO_2 Emissions from Grassland Remaining Grassland	CO_2	6.7	•	L_2 T_2	1990, 2012
CO_2 Emissions from Liming of Agricultural Soils	CO_2	3.9			
CO_2 Emissions from Urea Fertilization	CO_2	3.4			
CO_2 Emissions from Wetlands Remaining Wetlands	CO_2	0.8			
CO_2 Emissions from Land Converted to Grassland	CO_2	(8.5)			
CO_2 Emissions from Landfilled Yard Trimmings and Food Scraps	CO_2	(13.2)	•	T_1 L_2 T_2	1990_2
CO_2 Emissions from Cropland Remaining Cropland	CO_2	(26.5)	•	L_1 T_1 L_2 T_2	1990, 2012
CO_2 Emissions from Urban Trees	CO_2	(88.4)	•	L_1 T_1 L_2 T_2	1990, 2012
CO_2 Emissions from Changes in Forest Carbon Stocks	CO_2	(866.5)	•	L_1 T_1 L_2 T_2	1990, 2012
CH_4 Emissions from Forest Fires	CH_4	5.3	•	T_1 L_2 T_2	2012
N_2O Emissions from Forest Fires	N_2O	2.5	•	T_1 L_2 T_2	2012
N_2O Emissions from Settlement Soils	N_2O	1.5			
N_2O Emissions from Forest Soils	N_2O	0.4			
N_2O Emissions from Wetlands Remaining Wetlands	N_2O	+			

[a] For the ID criteria, L refers to a key category identified through a level assessment; T refers to a key category identified through a trend assessment and the subscripted number refers to either a Tier 1 or Tier 2 assessment (e.g., L_2 designates a source is a key category for a Tier 2 level assessment).

[b] If the source is a key category for both L_1 and L_2 (as designated in the ID criteria column), it is a key category for both assessments in the years provided unless noted by a subscript, in which case it is a key category only for that assessment in only that year (.e.g., 1990_2 designates a source is a key category for the Tier 2 assessment only in 1990).

[c] Emissions from these sources not included in totals.

+ Does not exceed 0.05 Tg CO_2 Eq.

Note: Parentheses indicate negative values (or sequestration).

Evaluation of Key Categories

Level Assessment

When using a Tier 1 approach for the level assessment, a predetermined cumulative emissions threshold is used to identify key categories. When source and sink categories are sorted in order of decreasing absolute emissions, those that fall at the top of the list and cumulatively account for 95 percent of emissions are considered key categories. The 95 percent threshold in the *IPCC Good Practice Guidance* (IPCC 2000) was designed to establish a general level where the key category analysis covers approximately 75 to 92 percent of inventory uncertainty.

Including the Tier 2 approach provides additional insight into why certain source categories are considered key, and how to prioritize inventory improvements. In the Tier 2 approach, the level assessment for each category from the Tier 1 approach is multiplied by its percent relative uncertainty. If the uncertainty reported is asymmetrical, the absolute value of the larger uncertainty is used. Uncertainty is not estimated for the following sources: CO_2 emissions from stationary combustion – geothermal energy; CO_2 emissions from mobile combustion by mode of transportation; CH_4 and N_2O emissions from mobile combustion by mode of off-road transportation; and CH_4 from the incineration of waste. While CO_2 emissions from geothermal energy are included in the overall emissions estimate, they are not an official IPCC source category. As a result, there are no guidelines to associate uncertainty with the emissions estimate; therefore, an uncertainty analysis was not conducted. The uncertainty associated with CO_2 from mobile combustion is applied to each mode's emissions estimate, and the uncertainty associated with off-road vehicle CH_4 and N_2O emissions are applied to both CH_4 and N_2O emissions from aviation, marine, and other sources. No uncertainty was associated with CH_4 emissions from waste incineration because emissions are less than 0.05 Gg CH_4 and an uncertainty analysis was not conducted. When source and sink categories are sorted in decreasing order of this calculation, those that fall at the top of the list and cumulatively account for 90 percent of emissions are considered key categories. The key categories identified by the Tier 2 level assessment may differ from those identified by the Tier 1 assessment. The final set of key categories includes all source and sink categories identified as key by either the Tier 1 or the Tier 2 assessment, keeping in mind that the two assessments are not mutually exclusive.

It is important to note that a key category analysis can be sensitive to the definitions of the source and sink categories. If a large source category is split into many subcategories, then the subcategories may have contributions to the total inventory that are too small for those source categories to be considered key. Similarly, a collection of small, non-key source categories adding up to less than 5 percent of total emissions could become key source categories if those source categories were aggregated into a single source category. The United States has attempted to define source and sink categories by the conventions which would allow comparison with other international key categories, while still maintaining the category definitions that constitute how the emissions estimates were calculated for this report. As such, some of the category names used in the key category analysis may differ from the names used in the main body of the report. Additionally, the United States accounts for some source categories, including fossil fuel feedstocks, international bunkers, and emissions from U.S. territories, that are derived from unique data sources using country-specific methodologies.

Table A- 4 through Table A- 7 contain the 1990 and 2012 level assessments for both with and without LULUCF sources and sinks, and contain further detail on where each source falls within the analysis. Tier 1 key categories are shaded dark gray. Additional key categories identified by the Tier 2 assessment are shaded light gray.

Trend Assessment

The Tier 1 approach for trend assessment is defined as the product of the source or sink category level assessment and the absolute difference between the source or sink category trend and the total trend. In turn, the source or sink category trend is defined as the change in emissions from the base year to the current year, as a percentage of current year emissions from that source or sink category. The total trend is the percentage change in total inventory emissions from the base year to the current year.

Thus, the source or sink category trend assessment will be large if the source or sink category represents a large percentage of emissions and/or has a trend that is quite different from the overall inventory trend. To determine key categories, the trend assessments are sorted in decreasing order, so that the source or sink categories with the highest trend assessments appear first. The trend assessments are summed until the threshold of 95 percent is reached; all categories that fall within that cumulative 95 percent are considered key categories.

For the Tier 2 approach, the trend assessment for each category from the Tier 1 approach is multiplied by its percent relative uncertainty. If the uncertainty reported is asymmetrical, the larger uncertainty is used. When source and sink categories are sorted in decreasing order of this calculation, those that fall at the top of the list and cumulatively account for 90 percent of emissions are considered key categories. The key categories identified by the Tier 2 trend assessment may differ from those identified by the Tier 1 assessment. The final set of key categories includes all source and sink categories identified as key by either the Tier 1 or the Tier 2 assessment, keeping in mind that the two assessments are not mutually exclusive.

Table A- 8 and Table A- 9 contain the 1990 through 2012 trend assessment for both with and without LULUCF sources and sinks, and contain further detail on where each source falls within the analysis. Tier 1 key categories are shaded dark gray. Additional key categories identified by the Tier 2 assessment are shaded light gray.

Table A- 4: 1990 Key Source Category Tier 1 and Tier 2 Analysis—Level Assessment, without LULUCF

IPCC Source Categories	Direct GHG	1990 Estimate (Tg CO_2 Eq.)	Tier 1 Level Assessment	Cumulative Total	Uncertainty	Tier 2 Level Assessment
CO_2 Emissions from Stationary Combustion - Coal - Electricity Generation	CO_2	1,547.6	0.25	0.25	10%	0.024
CO_2 Emissions from Mobile Combustion: Road	CO_2	1,188.9	0.19	0.44	7%	0.013
CO_2 Emissions from Stationary Combustion - Gas - Industrial	CO_2	408.9	0.07	0.51	7%	0.005
CO_2 Emissions from Stationary Combustion - Oil - Industrial	CO_2	280.9	0.05	0.55	20%	0.009
Direct N_2O Emissions from Agricultural Soil Management	N_2O	240.7	0.04	0.59	28%	0.011
CO_2 Emissions from Stationary Combustion - Gas - Residential	CO_2	238.0	0.04	0.63	7%	0.003
CO_2 Emissions from Mobile Combustion: Aviation	CO_2	187.4	0.03	0.66	7%	0.002
CO_2 Emissions from Stationary Combustion - Gas - Electricity Generation	CO_2	175.3	0.03	0.69	5%	0.001
CH_4 Emissions from Natural Gas Systems	CH_4	156.4	0.03	0.71	30%	0.007
CO_2 Emissions from Stationary Combustion - Coal - Industrial	CO_2	155.3	0.02	0.74	16%	0.004
CH_4 Emissions from Landfills	CH_4	147.8	0.02	0.76	56%	0.013

CO_2 Emissions from Stationary Combustion - Gas - Commercial	CO_2	142.1	0.02	0.78	7%	0.002
CH_4 Emissions from Enteric Fermentation	CH_4	137.9	0.02	0.81	18%	0.004
CO_2 Emissions from Non-Energy Use of Fuels	CO_2	120.8	0.02	0.82	35%	0.007
CO_2 Emissions from Iron and Steel Production & Metallurgical Coke Production	CO_2	99.8	0.02	0.84	17%	0.003
CO_2 Emissions from Stationary Combustion - Oil - Electricity Generation	CO_2	97.5	0.02	0.86	8%	0.001
CO_2 Emissions from Stationary Combustion - Oil - Residential	CO_2	97.4	0.02	0.87	6%	0.001
Fugitive Emissions from Coal Mining	CH_4	81.1	0.01	0.88	35%	0.005
CO_2 Emissions from Mobile Combustion: Other	CO_2	73.3	0.01	0.90	7%	0.001
CO_2 Emissions from Stationary Combustion - Oil - Commercial	CO_2	64.9	0.01	0.91	5%	0.001
CO_2 Emissions from Mobile Combustion: Marine	CO_2	44.5	0.01	0.91	7%	<0.001
Indirect N_2O Emissions from Applied Nitrogen	N_2O	41.4	0.01	0.92	151%	0.010
N_2O Emissions from Mobile Combustion: Road	N_2O	40.3	0.01	0.93	27%	0.002
CO_2 Emissions from Natural Gas Systems	CO_2	37.7	0.01	0.93	30%	0.002
HFC-23 Emissions from HCFC-22 Production	HFCs	36.4	0.01	0.94	10%	0.001
CH_4 Emissions from Petroleum Systems	CH_4	35.8	0.01	0.95	149%	0.009
CO_2 Emissions from Cement Production	CO_2	33.3	0.01	0.95	6%	<0.001
CH_4 Emissions from Manure Management	CH_4	31.5	0.01	0.96	20%	0.001
CO_2 Emissions from Stationary Combustion - Oil - U.S. Territories	CO_2	27.2	<0.01	0.96	11%	<0.001
SF_6 Emissions from Electrical Transmission and Distribution	SF_6	26.7	<0.01	0.96	25%	0.001
PFC Emissions from Aluminum Production	PFCs	18.4	<0.01	0.97	6%	<0.001
N_2O Emissions from Nitric Acid Production	N_2O	18.2	<0.01	0.97	38%	0.001
N_2O Emissions from Adipic Acid Production	N_2O	15.8	<0.01	0.97	4%	<0.001
N_2O Emissions from Manure Management	N_2O	14.4	<0.01	0.97	24%	0.001
CH_4 Emissions from Wastewater Treatment	CH_4	13.2	<0.01	0.98	27%	0.001
CO_2 Emissions from Ammonia Production	CO_2	13.0	<0.01	0.98	7%	<0.001
CO_2 Emissions from Stationary Combustion - Coal – Commercial	CO_2	12.0	<0.01	0.98	15%	<0.001
CO_2 Emissions from Lime Production	CO_2	11.4	<0.01	0.98	3%	<0.001
CO_2 Emissions from Incineration of Waste	CO_2	8.0	<0.01	0.98	14%	<0.001
CH_4 Emissions from Rice Cultivation	CH_4	7.7	<0.01	0.99	96%	0.001
Non-CO_2 Emissions from Stationary Combustion - Electricity Generation	N_2O	7.4	<0.01	0.99	171%	0.002
CO_2 Emissions from Aluminum Production	CO_2	6.8	<0.01	0.99	2%	<0.001
Fugitive Emissions from Abandoned Underground Coal Mines	CH_4	6.0	<0.01	0.99	26%	<0.001
SF_6 Emissions from Magnesium Production and Processing	SF_6	5.4	<0.01	0.99	12%	<0.001
CO_2 Emissions from Other Process Uses of Carbonates	CO_2	4.9	<0.01	0.99	20%	<0.001
Non-CO_2 Emissions from Stationary Combustion - Residential	CH_4	4.6	<0.01	0.99	225%	0.002
N_2O Emissions from Product Uses	N_2O	4.4	<0.01	0.99	24%	<0.001
CH_4 Emissions from Mobile Combustion: Road	CH_4	4.2	<0.01	0.99	16%	<0.001
CO_2 Emissions from Urea Consumption for Non-Ag Purposes	CO_2	3.8	<0.01	0.99	10%	<0.001
N_2O Emissions from Wastewater Treatment	N_2O	3.5	<0.01	0.99	100%	0.001
CO_2 Emissions from Petrochemical Production	CO_2	3.4	<0.01	0.99	27%	<0.001
Non-CO_2 Emissions from Stationary Combustion - Industrial	N_2O	3.3	<0.01	0.99	211%	0.001
CO_2 Emissions from Stationary Combustion - Coal - Residential	CO_2	3.0	<0.01	0.99	NE	<0.001
PFC, HFC, and SF_6 Emissions from Semiconductor Manufacture	Several	2.9	<0.01	0.99	5%	<0.001
CO_2 Emissions from Soda Ash Production and Consumption	CO_2	2.7	<0.01	1.00	6%	<0.001
CH_4 Emissions from Petrochemical Production	CH_4	2.3	<0.01	1.00	10%	<0.001
CO_2 Emissions from Ferroalloy Production	CO_2	2.2	<0.01	1.00	12%	<0.001
N_2O Emissions from Mobile Combustion: Aviation	N_2O	1.8	<0.01	1.00	2%	<0.001
Non-CO_2 Emissions from Stationary Combustion - Industrial	CH_4	1.6	<0.01	1.00	49%	<0.001

CO_2 Emissions from Phosphoric Acid Production	CO_2	1.6	<0.01	1.00	21%	<0.001
CO_2 Emissions from Glass Production	CO_2	1.5	<0.01	1.00	5%	<0.001
CO_2 Emissions from Carbon Dioxide Consumption	CO_2	1.4	<0.01	1.00	40%	<0.001
N_2O Emissions from Mobile Combustion: Other	N_2O	1.3	<0.01	1.00	1%	<0.001
CO_2 Emissions from Titanium Dioxide Production	CO_2	1.2	<0.01	1.00	13%	<0.001
Non-CO_2 Emissions from Stationary Combustion - Residential	N_2O	1.1	<0.01	1.00	205%	<0.001
CH_4 Emissions from Iron and Steel Production & Metallurgical Coke Production	CH_4	1.0	<0.01	1.00	22%	<0.001
Non-CO_2 Emissions from Stationary Combustion - Commercial	CH_4	0.9	<0.01	1.00	138%	<0.001
CO_2 Emissions from Stationary Combustion - Coal - U.S. Territories	CO_2	0.6	<0.01	1.00	19%	<0.001
CO_2 Emissions from Zinc Production	CO_2	0.6	<0.01	1.00	17%	<0.001
N_2O Emissions from Mobile Combustion: Marine	N_2O	0.6	<0.01	1.00	16%	<0.001
CO_2 Emissions from Lead Production	CO_2	0.5	<0.01	1.00	15%	<0.001
N_2O Emissions from Incineration of Waste	N_2O	0.5	<0.01	1.00	313%	<0.001
CO_2 Emissions from Stationary Combustion - Geothermal Energy	CO_2	0.4	<0.01	1.00	NA	<0.001
CO_2 Emissions from Petroleum Systems	CO_2	0.4	<0.01	1.00	149%	<0.001
Non-CO_2 Emissions from Stationary Combustion - Commercial	N_2O	0.4	<0.01	1.00	38%	<0.001
CO_2 Emissions from Silicon Carbide Production and Consumption	CO_2	0.4	<0.01	1.00	9%	<0.001
N_2O Emissions from Composting	N_2O	0.4	<0.01	1.00	50%	<0.001
Non-CO_2 Emissions from Stationary Combustion - Electricity Generation	CH_4	0.3	<0.01	1.00	3%	<0.001
Emissions from Substitutes for Ozone Depleting Substances	Several	0.3	<0.01	1.00	14%	<0.001
CH_4 Emissions from Composting	CH_4	0.3	<0.01	1.00	50%	<0.001
CH_4 Emissions from Mobile Combustion: Other	CH_4	0.3	<0.01	1.00	1%	<0.001
CH_4 Emissions from Field Burning of Agricultural Residues	CH_4	0.3	<0.01	1.00	42%	<0.001
N_2O Emissions from Field Burning of Agricultural Residues	N_2O	0.1	<0.01	1.00	32%	<0.001
Non-CO_2 Emissions from Stationary Combustion - U.S. Territories	N_2O	0.1	<0.01	1.00	203%	<0.001
CH_4 Emissions from Mobile Combustion: Aviation	CH_4	0.1	<0.01	1.00	8%	<0.001
Non-CO_2 Emissions from Stationary Combustion - U.S. Territories	CH_4	+	<0.01	1.00	57%	<0.001
CH_4 Emissions from Silicon Carbide Production and Consumption	CH_4	+	<0.01	1.00	9%	<0.001
CH_4 Emissions from Mobile Combustion: Marine	CH_4	+	<0.01	1.00	4%	<0.001
CH_4 Emissions from Ferroalloy Production	CH_4	+	<0.01	1.00	11%	<0.001
CH_4 Emissions from Incineration of Waste	CH_4	+	<0.01	1.00	NE	<0.001
CO_2 Emissions from Stationary Combustion - Gas - U.S. Territories	CO_2	+	<0.01	1.00	17%	<0.001

Note: LULUCF sources and sinks are not included in this analysis.

[a] Percent relative uncertainty. If the corresponding uncertainty is asymmetrical, the uncertainty given here is the larger and always positive.

NE Uncertainty not estimated.

+ Does not exceed 0.05 Tg CO_2 Eq.

Table A- 5: 1990 Key Source Category Tier 1 and Tier 2 Analysis—Level Assessment, with LULUCF

IPCC Source Categories	Direct GHG	1990 Estimate (Tg CO_2 Eq.)	Tier 1 Level Assessment	Cumulative Total	Uncertainty	Tier 2 Level Assessment
CO_2 Emissions from Stationary Combustion - Coal - Electricity Generation	CO_2	1,547.6	0.22	0.22	10%	0.021
CO_2 Emissions from Mobile Combustion: Road	CO_2	1,188.9	0.17	0.38	7%	0.011
CO_2 Emissions from Changes in Forest Carbon Stocks	CO_2	704.6	0.10	0.48	15%	0.015
CO_2 Emissions from Stationary Combustion - Gas - Industrial	CO_2	408.9	0.06	0.54	7%	0.004

CO_2 Emissions from Stationary Combustion - Oil - Industrial	CO_2	280.9	0.04	0.58	20%	0.008
Direct N_2O Emissions from Agricultural Soil Management	N_2O	240.7	0.03	0.61	28%	0.010
CO_2 Emissions from Stationary Combustion - Gas - Residential	CO_2	238.0	0.03	0.65	7%	0.002
CO_2 Emissions from Mobile Combustion: Aviation	CO_2	187.4	0.03	0.67	7%	0.002
CO_2 Emissions from Stationary Combustion - Gas - Electricity Generation	CO_2	175.3	0.02	0.70	5%	0.001
CH_4 Emissions from Natural Gas Systems	CH_4	156.4	0.02	0.72	30%	0.007
CO_2 Emissions from Stationary Combustion - Coal - Industrial	CO_2	155.3	0.02	0.74	16%	0.003
CH_4 Emissions from Landfills	CH_4	147.8	0.02	0.76	56%	0.012
CO_2 Emissions from Stationary Combustion - Gas - Commercial	CO_2	142.1	0.02	0.78	7%	0.001
CH_4 Emissions from Enteric Fermentation	CH_4	137.9	0.02	0.80	18%	0.003
CO_2 Emissions from Non-Energy Use of Fuels	CO_2	120.8	0.02	0.82	35%	0.006
CO_2 Emissions from Iron and Steel Production & Metallurgical Coke Production	CO_2	99.8	0.01	0.83	17%	0.002
CO_2 Emissions from Stationary Combustion - Oil - Electricity Generation	CO_2	97.5	0.01	0.85	8%	0.001
CO_2 Emissions from Stationary Combustion - Oil - Residential	CO_2	97.4	0.01	0.86	6%	0.001
Fugitive Emissions from Coal Mining	CH_4	81.1	0.01	0.87	35%	0.004
CO_2 Emissions from Mobile Combustion: Other	CO_2	73.3	0.01	0.88	7%	0.001
CO_2 Emissions from Stationary Combustion - Oil - Commercial	CO_2	64.9	0.01	0.89	5%	<0.001
CO_2 Emissions from Urban Trees	CO_2	60.4	0.01	0.90	47%	0.004
CO_2 Emissions from Cropland Remaining Cropland	CO_2	51.9	0.01	0.91	167%	0.012
CO_2 Emissions from Mobile Combustion: Marine	CO_2	44.5	0.01	0.91	7%	<0.001
Indirect N_2O Emissions from Applied Nitrogen	N_2O	41.4	0.01	0.92	151%	0.009
N_2O Emissions from Mobile Combustion: Road	N_2O	40.3	0.01	0.93	27%	0.002
CO_2 Emissions from Natural Gas Systems	CO_2	37.7	0.01	0.93	30%	0.002
HFC-23 Emissions from HCFC-22 Production	HFCs	36.4	0.01	0.94	10%	0.001
CH_4 Emissions from Petroleum Systems	CH_4	35.8	0.01	0.94	149%	0.007
CO_2 Emissions from Cement Production	CO_2	33.3	<0.01	0.95	6%	<0.001
CH_4 Emissions from Manure Management	CH_4	31.5	<0.01	0.95	20%	0.001
CO_2 Emissions from Stationary Combustion - Oil - U.S. Territories	CO_2	27.2	<0.01	0.95	11%	<0.001
CO_2 Emissions from Land Converted to Cropland	CO_2	26.9	<0.01	0.96	77%	0.003
SF_6 Emissions from Electrical Transmission and Distribution	SF_6	26.7	<0.01	0.96	25%	0.001
CO_2 Emissions from Landfilled Yard Trimmings and Food Scraps	CO_2	24.2	<0.01	0.96	60%	0.002
PFC Emissions from Aluminum Production	PFCs	18.4	<0.01	0.97	6%	<0.001
N_2O Emissions from Nitric Acid Production	N_2O	18.2	<0.01	0.97	38%	0.001
N_2O Emissions from Adipic Acid Production	N_2O	15.8	<0.01	0.97	4%	<0.001
N_2O Emissions from Manure Management	N_2O	14.4	<0.01	0.97	24%	<0.001
CH_4 Emissions from Wastewater Treatment	CH_4	13.2	<0.01	0.98	27%	0.001
CO_2 Emissions from Ammonia Production	CO_2	13.0	<0.01	0.98	7%	<0.001
CO_2 Emissions from Stationary Combustion - Coal – Commercial	CO_2	12.0	<0.01	0.98	15%	<0.001
CO_2 Emissions from Lime Production	CO_2	11.4	<0.01	0.98	3%	<0.001
CO_2 Emissions from Grassland Remaining Grassland	CO_2	9.6	<0.01	0.98	529%	0.007
CO_2 Emissions from Incineration of Waste	CO_2	8.0	<0.01	0.98	14%	<0.001
CH_4 Emissions from Rice Cultivation	CH_4	7.7	<0.01	0.98	96%	0.001
Non-CO_2 Emissions from Stationary Combustion - Electricity Generation	N_2O	7.4	<0.01	0.99	171%	0.002
CO_2 Emissions from Land Converted to Grassland	CO_2	7.3	<0.01	0.99	108%	0.001
CO_2 Emissions from Aluminum Production	CO_2	6.8	<0.01	0.99	2%	<0.001
Fugitive Emissions from Abandoned Underground Coal Mines	CH_4	6.0	<0.01	0.99	26%	<0.001
SF_6 Emissions from Magnesium Production and Processing	SF_6	5.4	<0.01	0.99	12%	<0.001

CO_2 Emissions from Other Process Uses of Carbonates	CO_2	4.9	<0.01	0.99	20%	<0.001
CO_2 Emissions from Liming of Agricultural Soils	CO_2	4.7	<0.01	0.99	106%	0.001
Non-CO_2 Emissions from Stationary Combustion - Residential	CH_4	4.6	<0.01	0.99	225%	0.001
N_2O Emissions from Product Uses	N_2O	4.4	<0.01	0.99	24%	<0.001
CH_4 Emissions from Mobile Combustion: Road	CH_4	4.2	<0.01	0.99	16%	<0.001
CO_2 Emissions from Urea Consumption for Non-Ag Purposes	CO_2	3.8	<0.01	0.99	10%	<0.001
N_2O Emissions from Wastewater Treatment	N_2O	3.5	<0.01	0.99	100%	<0.001
CO_2 Emissions from Petrochemical Production	CO_2	3.4	<0.01	0.99	27%	<0.001
Non-CO_2 Emissions from Stationary Combustion - Industrial	N_2O	3.3	<0.01	0.99	211%	0.001
CO_2 Emissions from Stationary Combustion - Coal - Residential	CO_2	3.0	<0.01	0.99	NE	<0.001
PFC, HFC, and SF_6 Emissions from Semiconductor Manufacture	Several	2.9	<0.01	0.99	5%	<0.001
CO_2 Emissions from Soda Ash Production and Consumption	CO_2	2.7	<0.01	1.00	6%	<0.001
CH_4 Emissions from Forest Fires	CH_4	2.5	<0.01	1.00	176%	0.001
CO_2 Emissions from Urea Fertilization	CO_2	2.4	<0.01	1.00	43%	<0.001
CH_4 Emissions from Petrochemical Production	CH_4	2.3	<0.01	1.00	10%	<0.001
CO_2 Emissions from Ferroalloy Production	CO_2	2.2	<0.01	1.00	12%	<0.001
N_2O Emissions from Forest Fires	N_2O	2.0	<0.01	1.00	144%	<0.001
N_2O Emissions from Mobile Combustion: Aviation	N_2O	1.8	<0.01	1.00	2%	<0.001
Non-CO_2 Emissions from Stationary Combustion - Industrial	CH_4	1.6	<0.01	1.00	49%	<0.001
CO_2 Emissions from Phosphoric Acid Production	CO_2	1.6	<0.01	1.00	21%	<0.001
CO_2 Emissions from Glass Production	CO_2	1.5	<0.01	1.00	5%	<0.001
CO_2 Emissions from Carbon Dioxide Consumption	CO_2	1.4	<0.01	1.00	40%	<0.001
N_2O Emissions from Mobile Combustion: Other	N_2O	1.3	<0.01	1.00	1%	<0.001
CO_2 Emissions from Titanium Dioxide Production	CO_2	1.2	<0.01	1.00	13%	<0.001
Non-CO_2 Emissions from Stationary Combustion - Residential	N_2O	1.1	<0.01	1.00	205%	<0.001
CO_2 Emissions from Wetlands Remaining Wetlands	CO_2	1.0	<0.01	1.00	30%	<0.001
N_2O Emissions from Settlement Soils	N_2O	1.0	<0.01	1.00	163%	<0.001
CH_4 Emissions from Iron and Steel Production & Metallurgical Coke Production	CH_4	1.0	<0.01	1.00	22%	<0.001
Non-CO_2 Emissions from Stationary Combustion - Commercial	CH_4	0.9	<0.01	1.00	138%	<0.001
CO_2 Emissions from Stationary Combustion - Coal - U.S. Territories	CO_2	0.6	<0.01	1.00	19%	<0.001
CO_2 Emissions from Zinc Production	CO_2	0.6	<0.01	1.00	17%	<0.001
N_2O Emissions from Mobile Combustion: Marine	N_2O	0.6	<0.01	1.00	16%	<0.001
CO_2 Emissions from Lead Production	CO_2	0.5	<0.01	1.00	15%	<0.001
N_2O Emissions from Incineration of Waste	N_2O	0.5	<0.01	1.00	313%	<0.001
CO_2 Emissions from Stationary Combustion - Geothermal Energy	CO_2	0.4	<0.01	1.00	NA	<0.001
CO_2 Emissions from Petroleum Systems	CO_2	0.4	<0.01	1.00	149%	<0.001
Non-CO_2 Emissions from Stationary Combustion - Commercial	N_2O	0.4	<0.01	1.00	38%	<0.001
CO_2 Emissions from Silicon Carbide Production and Consumption	CO_2	0.4	<0.01	1.00	9%	<0.001
N_2O Emissions from Composting	N_2O	0.4	<0.01	1.00	50%	<0.001
Non-CO_2 Emissions from Stationary Combustion - Electricity Generation	CH_4	0.3	<0.01	1.00	3%	<0.001
Emissions from Substitutes for Ozone Depleting Substances	Several	0.3	<0.01	1.00	14%	<0.001
CH_4 Emissions from Composting	CH_4	0.3	<0.01	1.00	50%	<0.001
CH_4 Emissions from Mobile Combustion: Other	CH_4	0.3	<0.01	1.00	1%	<0.001
CH_4 Emissions from Field Burning of Agricultural Residues	CH_4	0.3	<0.01	1.00	42%	<0.001
N_2O Emissions from Field Burning of Agricultural Residues	N_2O	0.1	<0.01	1.00	32%	<0.001
Non-CO_2 Emissions from Stationary Combustion - U.S. Territories	N_2O	0.1	<0.01	1.00	203%	<0.001

N_2O Emissions from Forest Soils	N_2O	0.1	<0.01	1.00	211%	<0.001
CH_4 Emissions from Mobile Combustion: Aviation	CH_4	0.1	<0.01	1.00	8%	<0.001
Non-CO_2 Emissions from Stationary Combustion - U.S. Territories	CH_4	+	<0.01	1.00	57%	<0.001
CH_4 Emissions from Silicon Carbide Production and Consumption	CH_4	+	<0.01	1.00	9%	<0.001
CH_4 Emissions from Mobile Combustion: Marine	CH_4	+	<0.01	1.00	4%	<0.001
CH_4 Emissions from Ferroalloy Production	CH_4	+	<0.01	1.00	11%	<0.001
N_2O Emissions from Wetlands Remaining Wetlands	N_2O	+	<0.01	1.00	73%	<0.001
CH_4 Emissions from Incineration of Waste	CH_4	+	<0.01	1.00	NE	<0.001
CO_2 Emissions from Stationary Combustion - Gas - U.S. Territories	CO_2	+	<0.01	1.00	17%	<0.001

[a] Percent relative uncertainty. If the corresponding uncertainty is asymmetrical, the uncertainty given here is the larger and always positive.

NE Uncertainty not estimated.

+ Does not exceed 0.05 Tg CO_2 Eq.

Table A- 6: 2012 Key Source Category Tier 1 and Tier 2 Analysis—Level Assessment, without LULUCF

IPCC Source Categories	Direct GHG	2012 Estimate (Tg CO_2 Eq.)	Tier 1 Level Assessment	Cumulative Total	Uncertainty	Tier 2 Level Assessment
CO_2 Emissions from Stationary Combustion - Coal - Electricity Generation	CO_2	1,511.2	0.23	0.23	10%	0.022
CO_2 Emissions from Mobile Combustion: Road	CO_2	1,469.8	0.23	0.46	7%	0.015
CO_2 Emissions from Stationary Combustion - Gas - Electricity Generation	CO_2	492.2	0.08	0.54	5%	0.004
CO_2 Emissions from Stationary Combustion - Gas - Industrial	CO_2	434.7	0.07	0.60	7%	0.005
CO_2 Emissions from Stationary Combustion - Oil - Industrial	CO_2	265.2	0.04	0.64	20%	0.008
Direct N_2O Emissions from Agricultural Soil Management	N_2O	260.9	0.04	0.68	28%	0.011
CO_2 Emissions from Stationary Combustion - Gas - Residential	CO_2	224.8	0.03	0.72	7%	0.002
CO_2 Emissions from Stationary Combustion - Gas - Commercial	CO_2	156.9	0.02	0.74	7%	0.002
Emissions from Substitutes for Ozone Depleting Substances	Several	146.8	0.02	0.76	14%	0.003
CO_2 Emissions from Mobile Combustion: Aviation	CO_2	145.1	0.02	0.79	7%	0.001
CH_4 Emissions from Enteric Fermentation	CH_4	141.0	0.02	0.81	18%	0.004
CH_4 Emissions from Natural Gas Systems	CH_4	129.9	0.02	0.83	30%	0.006
CO_2 Emissions from Non-Energy Use of Fuels	CO_2	110.3	0.02	0.85	35%	0.006
CH_4 Emissions from Landfills	CH_4	102.8	0.02	0.86	56%	0.009
CO_2 Emissions from Mobile Combustion: Other	CO_2	84.5	0.01	0.87	7%	0.001
CO_2 Emissions from Stationary Combustion - Coal - Industrial	CO_2	74.3	0.01	0.89	16%	0.002
CO_2 Emissions from Stationary Combustion - Oil - Residential	CO_2	64.1	0.01	0.90	6%	0.001
Fugitive Emissions from Coal Mining	CH_4	55.8	0.01	0.90	35%	0.003
CO_2 Emissions from Iron and Steel Production & Metallurgical Coke Production	CO_2	54.3	0.01	0.91	17%	0.001
CH_4 Emissions from Manure Management	CH_4	52.9	0.01	0.92	20%	0.002
Indirect N_2O Emissions from Applied Nitrogen	N_2O	45.7	0.01	0.93	151%	0.011
CO_2 Emissions from Stationary Combustion - Oil - U.S. Territories	CO_2	44.7	0.01	0.94	11%	0.001
CO_2 Emissions from Mobile Combustion: Marine	CO_2	40.1	0.01	0.94	7%	<0.001
CO_2 Emissions from Stationary Combustion - Oil - Commercial	CO_2	36.4	0.01	0.95	5%	<0.001
CO_2 Emissions from Natural Gas Systems	CO_2	35.2	0.01	0.95	30%	0.002
CO_2 Emissions from Cement Production	CO_2	35.1	0.01	0.96	6%	<0.001

CH_4 Emissions from Petroleum Systems	CH_4	31.7	<0.01	0.96	149%	0.007
CO_2 Emissions from Stationary Combustion - Oil - Electricity Generation	CO_2	18.8	<0.01	0.97	8%	<0.001
Non-CO_2 Emissions from Stationary Combustion - Electricity Generation	N_2O	18.3	<0.01	0.97	171%	0.005
N_2O Emissions from Manure Management	N_2O	18.0	<0.01	0.97	24%	0.001
N_2O Emissions from Nitric Acid Production	N_2O	15.3	<0.01	0.97	38%	0.001
CO_2 Emissions from Lime Production	CO_2	13.3	<0.01	0.98	3%	<0.001
CH_4 Emissions from Wastewater Treatment	CH_4	12.8	<0.01	0.98	27%	0.001
N_2O Emissions from Mobile Combustion: Road	N_2O	12.6	<0.01	0.98	27%	0.001
CO_2 Emissions from Incineration of Waste	CO_2	12.2	<0.01	0.98	14%	<0.001
CO_2 Emissions from Ammonia Production	CO_2	9.4	<0.01	0.98	7%	<0.001
CO_2 Emissions from Other Process Uses of Carboantes	CO_2	8.0	<0.01	0.98	20%	<0.001
CH_4 Emissions from Rice Cultivation	CH_4	7.4	<0.01	0.99	96%	0.001
SF_6 Emissions from Electrical Transmission and Distribution	SF_6	6.0	<0.01	0.99	25%	<0.001
N_2O Emissions from Adipic Acid Production	N_2O	5.8	<0.01	0.99	4%	<0.001
CO_2 Emissions from Urea Consumption for Non-Ag Purposes	CO_2	5.2	<0.01	0.99	10%	<0.001
N_2O Emissions from Wastewater Treatment	N_2O	5.0	<0.01	0.99	100%	0.001
Fugitive Emissions from Abandoned Underground Coal Mines	CH_4	4.7	<0.01	0.99	26%	<0.001
N_2O Emissions from Product Uses	N_2O	4.4	<0.01	0.99	24%	<0.001
HFC-23 Emissions from HCFC-22 Production	HFCs	4.3	<0.01	0.99	10%	<0.001
CO_2 Emissions from Stationary Combustion - Coal - Commercial	CO_2	4.1	<0.01	0.99	15%	<0.001
PFC, HFC, and SF_6 Emissions from Semiconductor Manufacture	Several	3.7	<0.01	0.99	5%	<0.001
CO_2 Emissions from Petrochemical Production	CO_2	3.5	<0.01	0.99	27%	<0.001
CO_2 Emissions from Aluminum Production	CO_2	3.4	<0.01	0.99	2%	<0.001
CO_2 Emissions from Stationary Combustion - Coal - U.S. Territories	CO_2	3.4	<0.01	0.99	19%	<0.001
Non-CO_2 Emissions from Stationary Combustion - Residential	CH_4	3.1	<0.01	0.99	225%	0.001
CH_4 Emissions from Petrochemical Production	CH_4	3.1	<0.01	0.99	10%	<0.001
CO_2 Emissions from Soda Ash Production and Consumption	CO_2	2.7	<0.01	0.99	6%	<0.001
PFC Emissions from Aluminum Production	PFCs	2.5	<0.01	1.00	6%	<0.001
Non-CO_2 Emissions from Stationary Combustion - Industrial	N_2O	2.5	<0.01	1.00	211%	0.001
N_2O Emissions from Mobile Combustion: Other	N_2O	2.0	<0.01	1.00	1%	<0.001
CO_2 Emissions from Carbon Dioxide Consumption	CO_2	1.8	<0.01	1.00	40%	<0.001
N_2O Emissions from Composting	N_2O	1.8	<0.01	1.00	50%	<0.001
CO_2 Emissions from Titanium Dioxide Production	CO_2	1.7	<0.01	1.00	13%	<0.001
SF_6 Emissions from Magnesium Production and Processing	SF_6	1.7	<0.01	1.00	12%	<0.001
CO_2 Emissions from Ferroalloy Production	CO_2	1.7	<0.01	1.00	12%	<0.001
CH_4 Emissions from Composting	CH_4	1.6	<0.01	1.00	50%	<0.001
CO_2 Emissions from Stationary Combustion - Gas - U.S. Territories	CO_2	1.4	<0.01	1.00	17%	<0.001
CO_2 Emissions from Zinc Production	CO_2	1.4	<0.01	1.00	17%	<0.001
N_2O Emissions from Mobile Combustion: Aviation	N_2O	1.4	<0.01	1.00	2%	<0.001
CO_2 Emissions from Glass Production	CO_2	1.2	<0.01	1.00	5%	<0.001
Non-CO_2 Emissions from Stationary Combustion - Industrial	CH_4	1.2	<0.01	1.00	49%	<0.001
CH_4 Emissions from Mobile Combustion: Road	CH_4	1.2	<0.01	1.00	16%	<0.001
CO_2 Emissions from Phosphoric Acid Production	CO_2	1.1	<0.01	1.00	21%	<0.001
Non-CO_2 Emissions from Stationary Combustion - Residential	N_2O	0.8	<0.01	1.00	205%	<0.001

Non-CO_2 Emissions from Stationary Combustion - Commercial	CH_4	0.8	<0.01	1.00	138%	<0.001
CH_4 Emissions from Iron and Steel Production & Metallurgical Coke Production	CH_4	0.6	<0.01	1.00	22%	<0.001
N_2O Emissions from Mobile Combustion: Marine	N_2O	0.6	<0.01	1.00	16%	<0.001
CO_2 Emissions from Lead Production	CO_2	0.5	<0.01	1.00	15%	<0.001
Non-CO_2 Emissions from Stationary Combustion - Electricity Generation	CH_4	0.5	<0.01	1.00	3%	<0.001
CH_4 Emissions from Mobile Combustion: Other	CH_4	0.4	<0.01	1.00	1%	<0.001
CO_2 Emissions from Petroleum Systems	CO_2	0.4	<0.01	1.00	149%	<0.001
CO_2 Emissions from Stationary Combustion - Geothermal Energy	CO_2	0.4	<0.01	1.00	NA	<0.001
N_2O Emissions from Incineration of Waste	N_2O	0.4	<0.01	1.00	313%	<0.001
Non-CO_2 Emissions from Stationary Combustion - Commercial	N_2O	0.3	<0.01	1.00	38%	<0.001
CH_4 Emissions from Field Burning of Agricultural Residues	CH_4	0.3	<0.01	1.00	42%	<0.001
CO_2 Emissions from Silicon Carbide Production and Consumption	CO_2	0.2	<0.01	1.00	9%	<0.001
Non-CO_2 Emissions from Stationary Combustion - U.S. Territories	N_2O	0.1	<0.01	1.00	203%	<0.001
N_2O Emissions from Field Burning of Agricultural Residues	N_2O	0.1	<0.01	1.00	32%	<0.001
Non-CO_2 Emissions from Stationary Combustion - U.S. Territories	CH_4	0.1	<0.01	1.00	57%	<0.001
CH_4 Emissions from Mobile Combustion: Aviation	CH_4	+	<0.01	1.00	8%	<0.001
CH_4 Emissions from Mobile Combustion: Marine	CH_4	+	<0.01	1.00	4%	<0.001
CH_4 Emissions from Ferroalloy Production	CH_4	+	<0.01	1.00	11%	<0.001
CH_4 Emissions from Silicon Carbide Production and Consumption	CH_4	+	<0.01	1.00	9%	<0.001
CH_4 Emissions from Incineration of Waste	CH_4	+	<0.01	1.00	NE	<0.001
CO_2 Emissions from Stationary Combustion - Coal - Residential	CO_2	0.0	<0.01	1.00	NE	<0.001

Note: LULUCF sources and sinks are not included in this analysis.

[a] Percent relative uncertainty. If the corresponding uncertainty is asymmetrical, the uncertainty given here is the larger and always positive.

NE Uncertainty not estimated.

+ Does not exceed 0.05 Tg CO_2 Eq.

Table A- 7: 2012 Key Source Category Tier 1 and Tier 2 Analysis—Level Assessment with LULUCF

IPCC Source Categories	Direct GHG	2012 Estimate (Tg CO_2 Eq.)	Tier 1 Level Assessment	Cumulative Total	Uncertainty	Tier 2 Level Assessment
CO_2 Emissions from Stationary Combustion - Coal - Electricity Generation	CO_2	1,511.2	0.20	0.20	10%	0.019
CO_2 Emissions from Mobile Combustion: Road	CO_2	1,469.8	0.19	0.39	7%	0.013
CO_2 Emissions from Changes in Forest Carbon Stocks	CO_2	866.5	0.11	0.51	15%	0.018
CO_2 Emissions from Stationary Combustion - Gas - Electricity Generation	CO_2	492.2	0.07	0.57	5%	0.003
CO_2 Emissions from Stationary Combustion - Gas - Industrial	CO_2	434.7	0.06	0.63	7%	0.004
CO_2 Emissions from Stationary Combustion - Oil - Industrial	CO_2	265.2	0.04	0.67	20%	0.007
Direct N_2O Emissions from Agricultural Soil Management	N_2O	260.9	0.03	0.70	28%	0.010
CO_2 Emissions from Stationary Combustion - Gas - Residential	CO_2	224.8	0.03	0.73	7%	0.002
CO_2 Emissions from Stationary Combustion - Gas - Commercial	CO_2	156.9	0.02	0.75	7%	0.001
Emissions from Substitutes for Ozone Depleting Substances	Several	146.8	0.02	0.77	14%	0.003
CO_2 Emissions from Mobile Combustion: Aviation	CO_2	145.1	0.02	0.79	7%	0.001

CH_4 Emissions from Enteric Fermentation	CH_4	141.0	0.02	0.81	18%	0.003
CH_4 Emissions from Natural Gas Systems	CH_4	129.9	0.02	0.83	30%	0.005
CO_2 Emissions from Non-Energy Use of Fuels	CO_2	110.3	0.01	0.84	35%	0.005
CH_4 Emissions from Landfills	CH_4	102.8	0.01	0.86	56%	0.008
CO_2 Emissions from Urban Trees	CO_2	88.4	0.01	0.87	47%	0.006
CO_2 Emissions from Mobile Combustion: Other	CO_2	84.5	0.01	0.88	7%	0.001
CO_2 Emissions from Stationary Combustion - Coal - Industrial	CO_2	74.3	0.01	0.89	16%	0.002
CO_2 Emissions from Stationary Combustion - Oil - Residential	CO_2	64.1	0.01	0.90	6%	<0.001
Fugitive Emissions from Coal Mining	CH_4	55.8	0.01	0.90	35%	0.003
CO_2 Emissions from Iron and Steel Production & Metallurgical Coke Production	CO_2	54.3	0.01	0.91	17%	0.001
CH_4 Emissions from Manure Management	CH_4	52.9	0.01	0.92	20%	0.001
Indirect N_2O Emissions from Applied Nitrogen	N_2O	45.7	0.01	0.92	151%	0.009
CO_2 Emissions from Stationary Combustion - Oil - U.S. Territories	CO_2	44.7	0.01	0.93	11%	0.001
CO_2 Emissions from Mobile Combustion: Marine	CO_2	40.1	0.01	0.94	7%	<0.001
CO_2 Emissions from Stationary Combustion - Oil - Commercial	CO_2	36.4	<0.01	0.94	5%	<0.001
CO_2 Emissions from Natural Gas Systems	CO_2	35.2	<0.01	0.94	30%	0.001
CO_2 Emissions from Cement Production	CO_2	35.1	<0.01	0.95	6%	<0.001
CH_4 Emissions from Petroleum Systems	CH_4	31.7	<0.01	0.95	149%	0.006
CO_2 Emissions from Cropland Remaining Cropland	CO_2	26.5	<0.01	0.96	167%	0.006
CO_2 Emissions from Stationary Combustion - Oil - Electricity Generation	CO_2	18.8	<0.01	0.96	8%	<0.001
Non-CO_2 Emissions from Stationary Combustion - Electricity Generation	N_2O	18.3	<0.01	0.96	171%	0.004
N_2O Emissions from Manure Management	N_2O	18.0	<0.01	0.96	24%	0.001
CO_2 Emissions from Land Converted to Cropland	CO_2	16.8	<0.01	0.97	77%	0.002
CH_4 Emissions from Forest Fires	CH_4	15.3	<0.01	0.97	176%	0.004
N_2O Emissions from Nitric Acid Production	N_2O	15.3	<0.01	0.97	38%	0.001
CO_2 Emissions from Lime Production	CO_2	13.3	<0.01	0.97	3%	<0.001
CO_2 Emissions from Landfilled Yard Trimmings and Food Scraps	CO_2	13.0	<0.01	0.97	60%	0.001
CH_4 Emissions from Wastewater Treatment	CH_4	12.8	<0.01	0.98	27%	<0.001
N_2O Emissions from Mobile Combustion: Road	N_2O	12.6	<0.01	0.98	27%	<0.001
N_2O Emissions from Forest Fires	N_2O	12.5	<0.01	0.98	144%	0.002
CO_2 Emissions from Incineration of Waste	CO_2	12.2	<0.01	0.98	14%	<0.001
CO_2 Emissions from Ammonia Production	CO_2	9.4	<0.01	0.98	7%	<0.001
CO_2 Emissions from Land Converted to Grassland	CO_2	8.5	<0.01	0.98	108%	0.001
CO_2 Emissions from Other Process Uses of Carbonates	CO_2	8.0	<0.01	0.98	20%	<0.001
CH_4 Emissions from Rice Cultivation	CH_4	7.4	<0.01	0.99	96%	0.001
CO_2 Emissions from Grassland Remaining Grassland	CO_2	6.7	<0.01	0.99	529%	0.005
SF_6 Emissions from Electrical Transmission and Distribution	SF_6	6.0	<0.01	0.99	25%	<0.001
N_2O Emissions from Adipic Acid Production	N_2O	5.8	<0.01	0.99	4%	<0.001
CO_2 Emissions from Urea Consumption for Non-Ag Purposes	CO_2	5.2	<0.01	0.99	10%	<0.001
N_2O Emissions from Wastewater Treatment	N_2O	5.0	<0.01	0.99	100%	0.001
Fugitive Emissions from Abandoned Underground Coal Mines	CH_4	4.7	<0.01	0.99	26%	<0.001
N_2O Emissions from Product Uses	N_2O	4.4	<0.01	0.99	24%	<0.001
HFC-23 Emissions from HCFC-22 Production	HFCs	4.3	<0.01	0.99	10%	<0.001
CO_2 Emissions from Stationary Combustion - Coal - Commercial	CO_2	4.1	<0.01	0.99	15%	<0.001

CO_2 Emissions from Liming of Agricultural Soils	CO_2	3.9	<0.01	0.99	106%	0.001
PFC, HFC, and SF_6 Emissions from Semiconductor Manufacture	Several	3.7	<0.01	0.99	5%	<0.001
CO_2 Emissions from Petrochemical Production	CO_2	3.5	<0.01	0.99	27%	<0.001
CO_2 Emissions from Urea Fertilization	CO_2	3.4	<0.01	0.99	43%	<0.001
CO_2 Emissions from Aluminum Production	CO_2	3.4	<0.01	0.99	2%	<0.001
CO_2 Emissions from Stationary Combustion - Coal - U.S. Territories	CO_2	3.4	<0.01	0.99	19%	<0.001
Non-CO_2 Emissions from Stationary Combustion - Residential	CH_4	3.1	<0.01	0.99	225%	0.001
CH_4 Emissions from Petrochemical Production	CH_4	3.1	<0.01	0.99	10%	<0.001
CO_2 Emissions from Soda Ash Production and Consumption	CO_2	2.7	<0.01	1.00	6%	<0.001
PFC Emissions from Aluminum Production	PFCs	2.5	<0.01	1.00	6%	<0.001
Non-CO_2 Emissions from Stationary Combustion - Industrial	N_2O	2.5	<0.01	1.00	211%	0.001
N_2O Emissions from Mobile Combustion: Other	N_2O	2.0	<0.01	1.00	1%	<0.001
CO_2 Emissions from Carbon Dioxide Consumption	CO_2	1.8	<0.01	1.00	40%	<0.001
N_2O Emissions from Composting	N_2O	1.8	<0.01	1.00	50%	<0.001
CO_2 Emissions from Titanium Dioxide Production	CO_2	1.7	<0.01	1.00	13%	<0.001
SF_6 Emissions from Magnesium Production and Processing	SF_6	1.7	<0.01	1.00	12%	<0.001
CO_2 Emissions from Ferroalloy Production	CO_2	1.7	<0.01	1.00	12%	<0.001
CH_4 Emissions from Composting	CH_4	1.6	<0.01	1.00	50%	<0.001
N_2O Emissions from Settlement Soils	N_2O	1.5	<0.01	1.00	163%	<0.001
CO_2 Emissions from Stationary Combustion - Gas - U.S. Territories	CO_2	1.4	<0.01	1.00	17%	<0.001
CO_2 Emissions from Zinc Production	CO_2	1.4	<0.01	1.00	17%	<0.001
N_2O Emissions from Mobile Combustion: Aviation	N_2O	1.4	<0.01	1.00	2%	<0.001
CO_2 Emissions from Glass Production	CO_2	1.2	<0.01	1.00	5%	<0.001
Non-CO_2 Emissions from Stationary Combustion - Industrial	CH_4	1.2	<0.01	1.00	49%	<0.001
CH_4 Emissions from Mobile Combustion: Road	CH_4	1.2	<0.01	1.00	16%	<0.001
CO_2 Emissions from Phosphoric Acid Production	CO_2	1.1	<0.01	1.00	21%	<0.001
CO_2 Emissions from Wetlands Remaining Wetlands	CO_2	0.8	<0.01	1.00	30%	<0.001
Non-CO_2 Emissions from Stationary Combustion - Residential	N_2O	0.8	<0.01	1.00	205%	<0.001
Non-CO_2 Emissions from Stationary Combustion - Commercial	CH_4	0.8	<0.01	1.00	138%	<0.001
CH_4 Emissions from Iron and Steel Production & Metallurgical Coke Production	CH_4	0.6	<0.01	1.00	22%	<0.001
N_2O Emissions from Mobile Combustion: Marine	N_2O	0.6	<0.01	1.00	16%	<0.001
CO_2 Emissions from Lead Production	CO_2	0.5	<0.01	1.00	15%	<0.001
Non-CO_2 Emissions from Stationary Combustion - Electricity Generation	CH_4	0.5	<0.01	1.00	3%	<0.001
CH_4 Emissions from Mobile Combustion: Other	CH_4	0.4	<0.01	1.00	1%	<0.001
CO_2 Emissions from Petroleum Systems	CO_2	0.4	<0.01	1.00	149%	<0.001
CO_2 Emissions from Stationary Combustion - Geothermal Energy	CO_2	0.4	<0.01	1.00	NA	<0.001
N_2O Emissions from Incineration of Waste	N_2O	0.4	<0.01	1.00	313%	<0.001
N_2O Emissions from Forest Soils	N_2O	0.4	<0.01	1.00	211%	<0.001
Non-CO_2 Emissions from Stationary Combustion - Commercial	N_2O	0.3	<0.01	1.00	38%	<0.001
CH_4 Emissions from Field Burning of Agricultural Residues	CH_4	0.3	<0.01	1.00	42%	<0.001
CO_2 Emissions from Silicon Carbide Production and Consumption	CO_2	0.2	<0.01	1.00	9%	<0.001
Non-CO_2 Emissions from Stationary Combustion - U.S. Territories	N_2O	0.1	<0.01	1.00	203%	<0.001

N_2O Emissions from Field Burning of Agricultural Residues	N_2O	0.1	<0.01	1.00	32%	<0.001
Non-CO_2 Emissions from Stationary Combustion - U.S. Territories	CH_4	0.1	<0.01	1.00	57%	<0.001
CH_4 Emissions from Mobile Combustion: Aviation	CH_4	+	<0.01	1.00	8%	<0.001
CH_4 Emissions from Mobile Combustion: Marine	CH_4	+	<0.01	1.00	4%	<0.001
CH_4 Emissions from Ferroalloy Production	CH_4	+	<0.01	1.00	11%	<0.001
CH_4 Emissions from Silicon Carbide Production and Consumption	CH_4	+	<0.01	1.00	9%	<0.001
N_2O Emissions from Wetlands Remaining Wetlands	N_2O	+	<0.01	1.00	73%	<0.001
CH_4 Emissions from Incineration of Waste	CH_4	+	<0.01	1.00	NE	<0.001
CO_2 Emissions from Stationary Combustion - Coal - Residential	CO_2	0.0	<0.01	1.00	NE	<0.001

[a] Percent relative uncertainty. If the corresponding uncertainty is asymmetrical, the uncertainty given here is the larger and always positive.

NE Uncertainty not estimated.

+ Does not exceed 0.05 Tg CO_2 Eq.

Table A- 8: 1990-2012 Key Source Category Tier 1 and 2 Analysis—Trend Assessment, without LULUCF

IPCC Source Categories	Direct GHG	1990 Estimate (Tg CO_2 Eq.)	2012 Estimate (Tg CO_2 Eq.)	Tier 1 Trend Assessment	Tier 2 Trend Assessment	% Contribution to Trend	Cumulative Total
CO_2 Emissions from Stationary Combustion - Gas - Electricity Generation	CO_2	175.3	492.2	0.05	0.002	19.5	19
CO_2 Emissions from Mobile Combustion: Road	CO_2	1,188.9	1,469.8	0.04	0.002	14.4	34
Emissions from Substitutes for Ozone Depleting Substances	Several	0.3	146.8	0.02	0.003	9.2	43
CO_2 Emissions from Stationary Combustion - Coal - Electricity Generation	CO_2	1,547.6	1,511.2	0.02	0.002	6.5	50
CO_2 Emissions from Stationary Combustion - Coal - Industrial	CO_2	155.3	74.3	0.01	0.002	5.5	55
CO_2 Emissions from Stationary Combustion - Oil - Electricity Generation	CO_2	97.5	18.8	0.01	0.001	5.2	60
CH_4 Emissions from Landfills	CH_4	147.8	102.8	0.01	0.004	3.2	64
CO_2 Emissions from Mobile Combustion: Aviation	CO_2	187.4	145.1	0.01	0.001	3.2	67
CO_2 Emissions from Iron and Steel Production & Metallurgical Coke Production	CO_2	99.8	54.3	0.01	0.001	3.1	70
CO_2 Emissions from Stationary Combustion - Oil - Residential	CO_2	97.4	64.1	0.01	<0.001	2.4	72
HFC-23 Emissions from HCFC-22 Production	HFCs	36.4	4.3	0.01	0.001	2.1	74
CH_4 Emissions from Natural Gas Systems	CH_4	156.4	129.9	0.01	0.002	2.1	76
CO_2 Emissions from Stationary Combustion - Oil - Commercial	CO_2	64.9	36.4	0.01	<0.001	2.0	78
N_2O Emissions from Mobile Combustion: Road	N_2O	40.3	12.6	<0.01	0.001	1.9	80
Fugitive Emissions from Coal Mining	CH_4	81.1	55.8	<0.01	0.002	1.8	82
CO_2 Emissions from Stationary Combustion - Oil - Industrial	CO_2	280.9	265.2	<0.01	0.001	1.7	84
CO_2 Emissions from Stationary Combustion - Gas - Residential	CO_2	238.0	224.8	<0.01	<0.001	1.5	85
SF_6 Emissions from Electrical Transmission and Distribution	SF_6	26.7	6.0	<0.01	0.001	1.4	87
CH_4 Emissions from Manure Management	CH_4	31.5	52.9	<0.01	0.001	1.3	88
PFC Emissions from Aluminum Production	PFCs	18.4	2.5	<0.01	<0.001	1.1	89
CO_2 Emissions from Stationary Combustion - Oil - U.S. Territories	CO_2	27.2	44.7	<0.01	<0.001	1.0	90
CO_2 Emissions from Non-Energy Use of Fuels	CO_2	120.8	110.3	<0.01	0.001	1.0	91
N_2O Emissions from Adipic Acid Production	N_2O	15.8	5.8	<0.01	<0.001	0.7	92
Non-CO_2 Emissions from Stationary Combustion - Electricity Generation	N_2O	7.4	18.3	<0.01	0.003	0.7	92
Direct N_2O Emissions from Agricultural Soil	N_2O	240.7	260.9	<0.01	<0.001	0.6	93

Management							
CO_2 Emissions from Stationary Combustion - Gas - Commercial	CO_2	142.1	156.9	<0.01	<0.001	0.5	94
CO_2 Emissions from Stationary Combustion - Coal - Commercial	CO_2	12.0	4.1	<0.01	<0.001	0.5	94
CO_2 Emissions from Mobile Combustion: Other	CO_2	73.3	84.5	<0.01	<0.001	0.5	95
CO_2 Emissions from Stationary Combustion - Gas - Industrial	CO_2	408.9	434.7	<0.01	<0.001	0.5	95
CO_2 Emissions from Mobile Combustion: Marine	CO_2	44.5	40.1	<0.01	<0.001	0.4	95
CH_4 Emissions from Petroleum Systems	CH_4	35.8	31.7	<0.01	0.001	0.4	96
CO_2 Emissions from Ammonia Production	CO_2	13.0	9.4	<0.01	<0.001	0.3	96
CO_2 Emissions from Natural Gas Systems	CO_2	37.7	35.2	<0.01	<0.001	0.3	96
SF_6 Emissions from Magnesium Production and Processing	SF_6	5.4	1.7	<0.01	<0.001	0.2	97
CO_2 Emissions from Incineration of Waste	CO_2	8.0	12.2	<0.01	<0.001	0.2	97
CO_2 Emissions from Aluminum Production	CO_2	6.8	3.4	<0.01	<0.001	0.2	97
N_2O Emissions from Nitric Acid Production	N_2O	18.2	15.3	<0.01	<0.001	0.2	97
CH_4 Emissions from Mobile Combustion: Road	CH_4	4.2	1.2	<0.01	<0.001	0.2	97
CO_2 Emissions from Stationary Combustion - Coal - Residential	CO_2	3.0	0.0	<0.01	0.001	0.2	98
N_2O Emissions from Manure Management	N_2O	14.4	18.0	<0.01	<0.001	0.2	98
CO_2 Emissions from Other Process Uses of Carbonates	CO_2	4.9	8.0	<0.01	<0.001	0.2	98
CH_4 Emissions from Enteric Fermentation	CH_4	137.9	141.0	<0.01	<0.001	0.2	98
CO_2 Emissions from Stationary Combustion - Coal - U.S. Territories	CO_2	0.6	3.4	<0.01	<0.001	0.2	98
Indirect N_2O Emissions from Applied Nitrogen	N_2O	41.4	45.7	<0.01	0.001	0.2	98
Non-CO_2 Emissions from Stationary Combustion - Residential	CH_4	4.6	3.1	<0.01	0.001	0.1	98
Fugitive Emissions from Abandoned Underground Coal Mines	CH_4	6.0	4.7	<0.01	<0.001	0.1	99
CO_2 Emissions from Stationary Combustion - Gas - U.S. Territories	CO_2	+	1.4	<0.01	<0.001	0.1	99
N_2O Emissions from Wastewater Treatment	N_2O	3.5	5.0	<0.01	<0.001	0.1	99
CO_2 Emissions from Lime Production	CO_2	11.4	13.3	<0.01	<0.001	0.1	99
N_2O Emissions from Composting	N_2O	0.4	1.8	<0.01	<0.001	0.1	99
CO_2 Emissions from Urea Consumption for Non-Ag Purposes	CO_2	3.8	5.2	<0.01	<0.001	0.1	99
CH_4 Emissions from Composting	CH_4	0.3	1.6	<0.01	<0.001	0.1	99
CH_4 Emissions from Wastewater Treatment	CH_4	13.2	12.8	<0.01	<0.001	0.1	99
Non-CO_2 Emissions from Stationary Combustion - Industrial	N_2O	3.3	2.5	<0.01	<0.001	0.1	99
CO_2 Emissions from Zinc Production	CO_2	0.6	1.4	<0.01	<0.001	<0.1	99
CH_4 Emissions from Petrochemical Production	CH_4	2.3	3.1	<0.01	<0.001	<0.1	99
PFC, HFC, and SF_6 Emissions from Semiconductor Manufacture	Several	2.9	3.7	<0.01	<0.001	<0.1	99
CH_4 Emissions from Rice Cultivation	CH_4	7.7	7.4	<0.01	<0.001	<0.1	99
N_2O Emissions from Mobile Combustion: Other	N_2O	1.3	2.0	<0.01	<0.001	<0.1	99
CO_2 Emissions from Ferroalloy Production	CO_2	2.2	1.7	<0.01	<0.001	<0.1	99
CO_2 Emissions from Phosphoric Acid Production	CO_2	1.6	1.1	<0.01	<0.001	<0.1	100
N_2O Emissions from Mobile Combustion: Aviation	N_2O	1.8	1.4	<0.01	<0.001	<0.1	100
CO_2 Emissions from Titanium Dioxide Production	CO_2	1.2	1.7	<0.01	<0.001	<0.1	100
Non-CO_2 Emissions from Stationary Combustion - Industrial	CH_4	1.6	1.2	<0.01	<0.001	<0.1	100
CH_4 Emissions from Iron and Steel Production & Metallurgical Coke Production	CH_4	1.0	0.6	<0.01	<0.001	<0.1	100
Non-CO_2 Emissions from Stationary Combustion - Residential	N_2O	1.1	0.8	<0.01	<0.001	<0.1	100

CO_2 Emissions from Glass Production	CO_2	1.5	1.2	<0.01	<0.001	<0.1	100
CO_2 Emissions from Carbon Dioxide Consumption	CO_2	1.4	1.8	<0.01	<0.001	<0.1	100
CO_2 Emissions from Cement Production	CO_2	33.3	35.1	<0.01	<0.001	<0.1	100
CO_2 Emissions from Silicon Carbide Production and Consumption	CO_2	0.4	0.2	<0.01	<0.001	<0.1	100
N_2O Emissions from Product Uses	N_2O	4.4	4.4	<0.01	<0.001	<0.1	100
CO_2 Emissions from Soda Ash Production and Consumption	CO_2	2.7	2.7	<0.01	<0.001	<0.1	100
Non-CO_2 Emissions from Stationary Combustion - Electricity Generation	CH_4	0.3	0.5	<0.01	<0.001	<0.1	100
Non-CO_2 Emissions from Stationary Combustion - Commercial	CH_4	0.9	0.8	<0.01	<0.001	<0.1	100
CH_4 Emissions from Mobile Combustion: Other	CH_4	0.3	0.4	<0.01	<0.001	<0.1	100
N_2O Emissions from Incineration of Waste	N_2O	0.5	0.4	<0.01	<0.001	<0.1	100
Non-CO_2 Emissions from Stationary Combustion - Commercial	N_2O	0.4	0.3	<0.01	<0.001	<0.1	100
CO_2 Emissions from Petrochemical Production	CO_2	3.4	3.5	<0.01	<0.001	<0.1	100
Non-CO_2 Emissions from Stationary Combustion - U.S. Territories	N_2O	0.1	0.1	<0.01	<0.001	<0.1	100
N_2O Emissions from Mobile Combustion: Marine	N_2O	0.6	0.6	<0.01	<0.001	<0.1	100
CH_4 Emissions from Mobile Combustion: Aviation	CH_4	0.1	+	<0.01	<0.001	<0.1	100
CH_4 Emissions from Field Burning of Agricultural Residues	CH_4	0.3	0.3	<0.01	<0.001	<0.1	100
Non-CO_2 Emissions from Stationary Combustion - U.S. Territories	CH_4	+	0.1	<0.01	<0.001	<0.1	100
CH_4 Emissions from Silicon Carbide Production and Consumption	CH_4	+	+	<0.01	<0.001	<0.1	100
CO_2 Emissions from Stationary Combustion - Geothermal Energy	CO_2	0.4	0.4	<0.01	<0.001	<0.1	100
CO_2 Emissions from Lead Production	CO_2	0.5	0.5	<0.01	<0.001	<0.1	100
CH_4 Emissions from Ferroalloy Production	CH_4	+	+	<0.01	<0.001	<0.1	100
CO_2 Emissions from Petroleum Systems	CO_2	0.4	0.4	<0.01	<0.001	<0.1	100
N_2O Emissions from Field Burning of Agricultural Residues	N_2O	0.1	0.1	<0.01	<0.001	<0.1	100
CH_4 Emissions from Mobile Combustion: Marine	CH_4	+	+	<0.01	<0.001	<0.1	100
CH_4 Emissions from Incineration of Waste	CH_4	+	+	<0.01	<0.001	<0.1	100

Note: LULUCF sources and sinks are not included in this analysis.
\+ Does not exceed 0.05 Tg CO_2 Eq.

Table A- 9: 1990-2012 Key Source Category Tier 1 and 2 Analysis—Trend Assessment, with LULUCF

IPCC Source Categories	Direct GHG	1990 Estimate (Tg CO_2 Eq.)	2012 Estimate (Tg CO_2 Eq.)	Tier 1 Trend Assessment	Tier 2 Trend Assessment	Percent Contribution to Trend (%)	Cumulative Contribution to Trend (%)
CO_2 Emissions from Stationary Combustion - Gas - Electricity Generation	CO_2	175.3	492.2	0.04	0.002	16.6	17
CO_2 Emissions from Mobile Combustion: Road	CO_2	1,188.9	1,469.8	0.03	0.002	11.3	28
Emissions from Substitutes for Ozone Depleting Substances	Several	0.3	146.8	0.02	0.003	8.0	36
CO_2 Emissions from Stationary Combustion - Coal - Electricity Generation	CO_2	1,547.6	1,511.2	0.02	0.002	7.1	43
CO_2 Emissions from Changes in Forest Carbon Stocks	CO_2	704.6	866.5	0.02	0.003	6.5	49
CO_2 Emissions from Stationary Combustion - Coal - Industrial	CO_2	155.3	74.3	0.01	0.002	4.9	54
CO_2 Emissions from Stationary Combustion - Oil - Electricity Generation	CO_2	97.5	18.8	0.01	0.001	4.6	59
CH_4 Emissions from Landfills	CH_4	147.8	102.8	0.01	0.004	2.9	62

CO_2 Emissions from Mobile Combustion: Aviation	CO_2	187.4	145.1	0.01	<0.001	2.9	65
CO_2 Emissions from Iron and Steel Production & Metallurgical Coke Production	CO_2	99.8	54.3	0.01	0.001	2.8	68
CO_2 Emissions from Stationary Combustion - Oil - Residential	CO_2	97.4	64.1	0.01	<0.001	2.1	70
CH_4 Emissions from Natural Gas Systems	CH_4	156.4	129.9	0.01	0.002	2.0	72
HFC-23 Emissions from HCFC-22 Production	HFCs	36.4	4.3	<0.01	<0.001	1.9	74
CO_2 Emissions from Stationary Combustion - Oil - Industrial	CO_2	280.9	265.2	<0.01	0.001	1.8	75
CO_2 Emissions from Stationary Combustion - Oil - Commercial	CO_2	64.9	36.4	<0.01	<0.001	1.8	77
Fugitive Emissions from Coal Mining	CH_4	81.1	55.8	<0.01	0.001	1.6	79
N_2O Emissions from Mobile Combustion: Road	N_2O	40.3	12.6	<0.01	0.001	1.6	80
CO_2 Emissions from Cropland Remaining Cropland	CO_2	51.9	26.5	<0.01	0.007	1.6	82
CO_2 Emissions from Stationary Combustion - Gas - Residential	CO_2	238.0	224.8	<0.01	<0.001	1.5	83
CO_2 Emissions from Urban Trees	CO_2	60.4	88.4	<0.01	0.002	1.3	85
SF_6 Emissions from Electrical Transmission and Distribution	SF_6	26.7	6.0	<0.01	0.001	1.2	86
CH_4 Emissions from Manure Management	CH_4	31.5	52.9	<0.01	0.001	1.1	87
CO_2 Emissions from Non-Energy Use of Fuels	CO_2	120.8	110.3	<0.01	0.001	1.0	88
PFC Emissions from Aluminum Production	PFCs	18.4	2.5	<0.01	<0.001	0.9	89
CO_2 Emissions from Stationary Combustion - Oil - U.S. Territories	CO_2	27.2	44.7	<0.01	<0.001	0.9	90
CO_2 Emissions from Landfilled Yard Trimmings and Food Scraps	CO_2	24.2	13.0	<0.01	0.001	0.7	91
CH_4 Emissions from Forest Fires	CH_4	2.5	15.3	<0.01	0.003	0.7	91
CO_2 Emissions from Land Converted to Cropland	CO_2	26.9	16.8	<0.01	0.001	0.6	92
N_2O Emissions from Adipic Acid Production	N_2O	15.8	5.8	<0.01	<0.001	0.6	92
Non-CO_2 Emissions from Stationary Combustion - Electricity Generation	N_2O	7.4	18.3	<0.01	0.003	0.6	93
N_2O Emissions from Forest Fires	N_2O	2.0	12.5	<0.01	0.002	0.6	94
CO_2 Emissions from Stationary Combustion - Coal - Commercial	CO_2	12.0	4.1	<0.01	<0.001	0.5	94
CO_2 Emissions from Mobile Combustion: Marine	CO_2	44.5	40.1	<0.01	<0.001	0.4	94
CO_2 Emissions from Mobile Combustion: Other	CO_2	73.3	84.5	<0.01	<0.001	0.4	95
CH_4 Emissions from Petroleum Systems	CH_4	35.8	31.7	<0.01	0.001	0.3	95
CO_2 Emissions from Stationary Combustion - Gas - Commercial	CO_2	142.1	156.9	<0.01	<0.001	0.3	95
Direct N_2O Emissions from Agricultural Soil Management	N_2O	240.7	260.9	<0.01	<0.001	0.3	96
CH_4 Emissions from Enteric Fermentation	CH_4	137.9	141.0	<0.01	<0.001	0.3	96
CO_2 Emissions from Natural Gas Systems	CO_2	37.7	35.2	<0.01	<0.001	0.3	96
CO_2 Emissions from Ammonia Production	CO_2	13.0	9.4	<0.01	<0.001	0.2	97
SF_6 Emissions from Magnesium Production and Processing	SF_6	5.4	1.7	<0.01	<0.001	0.2	97
N_2O Emissions from Nitric Acid Production	N_2O	18.2	15.3	<0.01	<0.001	0.2	97
CO_2 Emissions from Aluminum Production	CO_2	6.8	3.4	<0.01	<0.001	0.2	97
CO_2 Emissions from Incineration of Waste	CO_2	8.0	12.2	<0.01	<0.001	0.2	97
CO_2 Emissions from Grassland Remaining Grassland	CO_2	9.6	6.7	<0.01	0.003	0.2	98
CH_4 Emissions from Mobile Combustion: Road	CH_4	4.2	1.2	<0.01	<0.001	0.2	98
CO_2 Emissions from Stationary Combustion - Coal - Residential	CO_2	3.0	+	<0.01	<0.001	0.2	98
CO_2 Emissions from Other Process Uses of	CO_2	4.9	8.0	<0.01	<0.001	0.2	98

Carbonates							
N_2O Emissions from Manure Management	N_2O	14.4	18.0	<0.01	<0.001	0.2	98
CO_2 Emissions from Stationary Combustion - Coal - U.S. Territories	CO_2	0.6	3.4	<0.01	<0.001	0.1	98
Non-CO_2 Emissions from Stationary Combustion - Residential	CH_4	4.6	3.1	<0.01	0.001	0.1	98
Indirect N_2O Emissions from Applied Nitrogen	N_2O	41.4	45.7	<0.01	<0.001	0.1	99
Fugitive Emissions from Abandoned Underground Coal Mines	CH_4	6.0	4.7	<0.01	<0.001	0.1	99
CO_2 Emissions from Stationary Combustion - Gas - U.S. Territories	CO_2	+	1.4	<0.01	<0.001	0.1	99
N_2O Emissions from Composting	N_2O	0.4	1.8	<0.01	<0.001	0.1	99
N_2O Emissions from Wastewater Treatment	N_2O	3.5	5.0	<0.01	<0.001	0.1	99
CH_4 Emissions from Composting	CH_4	0.3	1.6	<0.01	<0.001	0.1	99
CO_2 Emissions from Urea Consumption for Non-Ag Purposes	CO_2	3.8	5.2	<0.01	<0.001	0.1	99
CO_2 Emissions from Lime Production	CO_2	11.4	13.3	<0.01	<0.001	0.1	99
CH_4 Emissions from Wastewater Treatment	CH_4	13.2	12.8	<0.01	<0.001	0.1	99
Non-CO_2 Emissions from Stationary Combustion - Industrial	N_2O	3.3	2.5	<0.01	<0.001	0.1	99
CO_2 Emissions from Liming of Agricultural Soils	CO_2	4.7	3.9	<0.01	<0.001	0.1	99
CO_2 Emissions from Urea Fertilization	CO_2	2.4	3.4	<0.01	<0.001	<0.1	99
CO_2 Emissions from Stationary Combustion - Gas - Industrial	CO_2	408.9	434.7	<0.01	<0.001	<0.1	99
CH_4 Emissions from Rice Cultivation	CH_4	7.7	7.4	<0.01	<0.001	<0.1	99
CO_2 Emissions from Zinc Production	CO_2	0.6	1.4	<0.01	<0.001	<0.1	99
CO_2 Emissions from Land Converted to Grassland	CO_2	7.3	8.5	<0.01	<0.001	<0.1	99
CH_4 Emissions from Petrochemical Production	CH_4	2.3	3.1	<0.01	<0.001	<0.1	100
PFC, HFC, and SF_6 Emissions from Semiconductor Manufacture	Several	2.9	3.7	<0.01	<0.001	<0.1	100
CO_2 Emissions from Ferroalloy Production	CO_2	2.2	1.7	<0.01	<0.001	<0.1	100
N_2O Emissions from Mobile Combustion: Other	N_2O	1.3	2.0	<0.01	<0.001	<0.1	100
CO_2 Emissions from Phosphoric Acid Production	CO_2	1.6	1.1	<0.01	<0.001	<0.1	100
N_2O Emissions from Mobile Combustion: Aviation	N_2O	1.8	1.4	<0.01	<0.001	<0.1	100
CO_2 Emissions from Titanium Dioxide Production	CO_2	1.2	1.7	<0.01	<0.001	<0.1	100
Non-CO_2 Emissions from Stationary Combustion - Industrial	CH_4	1.6	1.2	<0.01	<0.001	<0.1	100
N_2O Emissions from Settlement Soils	N_2O	1.0	1.5	<0.01	<0.001	<0.1	100
Non-CO_2 Emissions from Stationary Combustion - Residential	N_2O	1.1	0.8	<0.01	<0.001	<0.1	100
CH_4 Emissions from Iron and Steel Production & Metallurgical Coke Production	CH_4	1.0	0.6	<0.01	<0.001	<0.1	100
CO_2 Emissions from Glass Production	CO_2	1.5	1.2	<0.01	<0.001	<0.1	100
CO_2 Emissions from Carbon Dioxide Consumption	CO_2	1.4	1.8	<0.01	<0.001	<0.1	100
N_2O Emissions from Forest Soils	N_2O	0.1	0.4	<0.01	<0.001	<0.1	100
N_2O Emissions from Product Uses	N_2O	4.4	4.4	<0.01	<0.001	<0.1	100
CO_2 Emissions from Wetlands Remaining Wetlands	CO_2	1.0	0.8	<0.01	<0.001	<0.1	100
CO_2 Emissions from Cement Production	CO_2	33.3	35.1	<0.01	<0.001	<0.1	100
CO_2 Emissions from Silicon Carbide Production and Consumption	CO_2	0.4	0.2	<0.01	<0.001	<0.1	100
CO_2 Emissions from Soda Ash Production and Consumption	CO_2	2.7	2.7	<0.01	<0.001	<0.1	100

Non-CO_2 Emissions from Stationary Combustion - Commercial	CH_4	0.9	0.8	<0.01	<0.001	<0.1	100
Non-CO_2 Emissions from Stationary Combustion - Electricity Generation	CH_4	0.3	0.5	<0.01	<0.001	<0.1	100
N_2O Emissions from Incineration of Waste	N_2O	0.5	0.4	<0.01	<0.001	<0.1	100
CH_4 Emissions from Mobile Combustion: Other	CH_4	0.3	0.4	<0.01	<0.001	<0.1	100
CO_2 Emissions from Petrochemical Production	CO_2	3.4	3.5	<0.01	<0.001	<0.1	100
Non-CO_2 Emissions from Stationary Combustion - Commercial	N_2O	0.4	0.3	<0.01	<0.001	<0.1	100
N_2O Emissions from Mobile Combustion: Marine	N_2O	0.6	0.6	<0.01	<0.001	<0.1	100
Non-CO_2 Emissions from Stationary Combustion - U.S. Territories	N_2O	0.1	0.1	<0.01	<0.001	<0.1	100
CH_4 Emissions from Field Burning of Agricultural Residues	CH_4	0.3	0.3	<0.01	<0.001	<0.1	100
CH_4 Emissions from Mobile Combustion: Aviation	CH_4	0.1	+	<0.01	<0.001	<0.1	100
Non-CO_2 Emissions from Stationary Combustion - U.S. Territories	CH_4	+	0.1	<0.01	<0.001	<0.1	100
CO_2 Emissions from Stationary Combustion - Geothermal Energy	CO_2	0.4	0.4	<0.01	<0.001	<0.1	100
CO_2 Emissions from Lead Production	CO_2	0.5	0.5	<0.01	<0.001	<0.1	100
CH_4 Emissions from Silicon Carbide Production and Consumption	CH_4	+	+	<0.01	<0.001	<0.1	100
CO_2 Emissions from Petroleum Systems	CO_2	0.4	0.4	<0.01	<0.001	<0.1	100
CH_4 Emissions from Ferroalloy Production	CH_4	+	+	<0.01	<0.001	<0.1	100
N_2O Emissions from Field Burning of Agricultural Residues	N_2O	0.1	0.1	<0.01	<0.001	<0.1	100
N_2O Emissions from Wetlands Remaining Wetlands	N_2O	+	+	<0.01	<0.001	<0.1	100
CH_4 Emissions from Incineration of Waste	CH_4	+	+	<0.01	<0.001	<0.1	100
CH_4 Emissions from Mobile Combustion: Marine	CH_4	+	+	<0.01	<0.001	<0.1	100

+ Does not exceed 0.05 Tg CO_2 Eq.

References

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

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

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

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

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

Adjusted consumption data are presented in Columns 2 through 8 of Table A- 11 through Table A- 33 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 the Constants, Units, and Conversions Annex). 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 2012 total adjusted energy consumption across all sectors, including territories, and energy types was 71,607.7 trillion British thermal units (TBtu), as indicated in the last entry of Column 13 in Table A- 10. This total excludes fuel used for non-energy purposes and fuel consumed as international bunkers, both of which were deducted in earlier steps.

Electricity 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. Further information on these electricity end uses is described in EIA's *Annual Energy Review* (EIA 2012).

There are also three basic differences between the consumption data presented in Table A- 10 through Table A-33 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.

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

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

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 UNFCCC are to include energy consumption within U.S. territories. Therefore, consumption estimates for U.S. territories[3] were added to domestic consumption of fossil fuels. Energy consumption data from U.S. territories are presented in Column 7 of Table A- 10 through Table A- 33. It is reported separately from domestic sectoral consumption, because it is collected separately by EIA with no sectoral disaggregation.

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

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

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

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

Step 3: Adjust for Conversion of Fossil Fuels and Exports

First, a portion of industrial “other” coal that is accounted for in EIA coal combustion statistics is actually used to make “synthetic natural gas” via coal gasification at the Dakota Gasification Plant, a synthetic natural gas plant. The plant produces synthetic natural gas and by-product CO_2. The synthetic natural gas enters the natural gas distribution system. Since October 2000, a portion of the CO_2 produced by the coal gasification plant has been exported to Canada by pipeline. The remainder of the CO_2 by-product from the plant is released to the atmosphere. The energy in this synthetic natural gas enters the natural gas distribution stream, and is accounted for in EIA natural gas combustion statistics. Because this energy of the synthetic natural gas is already accounted for as natural gas combustion, this amount of energy is deducted from the industrial coal consumption statistics to avoid double counting. The exported CO_2 is not emitted to the atmosphere in the United States, and therefore the energy used to produce this amount of CO_2 is subtracted from industrial other coal.

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

EPA conducted a separate bottom-up analysis of transportation fuel consumption based on data from the Federal Highway Administration (FHWA). The FHWA data indicated that the amount of distillate and motor gasoline consumption allocated to the transportation sector in the EIA statistics should be adjusted. Therefore, for the estimates presented in the U.S. Inventory, the transportation sector’s distillate fuel and motor gasoline consumption was adjusted upward to match the value obtained from the bottom-up analysis. As the total distillate and motor gasoline consumption

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

estimate from EIA are considered to be accurate at the national level, the distillate and motor gasoline consumption totals for the residential, commercial, and industrial sectors were adjusted downward proportionately.

Step 5: Subtract Consumption for Non-Energy Use

U.S. aggregate energy statistics include consumption of fossil fuels for non-energy purposes. Depending on the end-use, non-energy uses of fossil fuels can result in long term storage of some or all of the C contained in the fuel. For example, asphalt made from petroleum can sequester up to 100 percent of the C contained in the petroleum feedstock for extended periods of time. Other non-energy fossil fuel products, such as lubricants or plastics also store C, but can lose or emit some of this C when they are used and/or burned as waste. As the emission pathways of C used for non-energy purposes are vastly different than fuel combustion, these emissions are estimated separately in the Carbon Emitted in Products from Non-Energy Uses of Fossil Fuels section in this chapter. Therefore, the amount of fuels used for non-energy purposes, shown in Table A-34, was subtracted from total fuel consumption.

Step 6: Subtract Consumption of International Bunker Fuels

Emissions from international transport activities, or international bunker fuel consumption, are not included in national totals and instead reported separately, as required by the IPCC (IPCC/UNEP/OECD/IEA 1997) and UNFCCC inventory reporting guidelines (UNFCCC, 2006). EIA energy statistics, however, include these bunker fuels—jet fuel for aircraft, and distillate fuel oil and residual fuel oil for marine shipping—as part of fuel consumption by the transportation end-use sector. Therefore, the amount of consumption for international bunker fuels was estimated and subtracted from total fuel consumption (see Table A-35). Emissions from international bunker fuels have been estimated separately and not included in national totals.[4]

Step 7: Determine the C Content of All Fuels

The C content of combusted fossil fuels was estimated by multiplying adjusted energy consumption (Columns 2 through 8 of Table A- 11 through Table A- 33) by fuel-specific C content coefficients (see Table A- 36 and Table A- 37) that reflect the amount of C per unit of energy in each fuel. The C content coefficients used in the U.S. inventory were derived by EIA from detailed fuel information and are similar to the C content coefficients contained in the IPCC's default methodology (IPCC/UNEP/OECD/IEA 1997), with modifications reflecting fuel qualities specific to the United States.

Step 8: Estimate CO_2 Emissions

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

To determine total emissions by final end-use sector, emissions from electricity generation were distributed to each end-use sector according to its share of aggregate electricity consumption (see Table A-38). This pro-rated approach to allocating emissions from electricity generation may overestimate or underestimate emissions for particular sectors due to differences in the average C content of fuel mixes burned to generate electricity.

To provide a more detailed accounting of emissions from transportation, fuel consumption data by vehicle type and transportation mode were used to allocate emissions by fuel type calculated for the transportation end-use sector. Additional information on the allocation is available in Annex 3.2.

[BEGIN BOX]

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

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

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

For EPA's GHGRP 2010, 2011, and 2012 reporting years, facility-level fossil fuel combustion emissions reported through the GHGRP were categorized and distributed to specific industry types by utilizing facility-reported NAICS codes (as published by the U.S. Census Bureau), and associated data available from EIA's 2010 Manufacturing Energy Consumption Survey (MECS). As noted previously in this report, the definitions and provisions for reporting fuel types in EPA's GHGRP include some differences from the inventory's use of EIA national fuel statistics to meet the UNFCCC reporting guidelines. The IPCC has provided guidance on aligning facility-level reported fuels and fuel types published in national energy statistics, which guided this exercise.[5]

This year's effort represents an attempt to align, reconcile, and coordinate the facility-level reporting of fossil fuel combustion emissions under EPA's GHGRP with the national-level approach presented in this report. Consistent with recommendations for reporting the inventory to the UNFCCC, progress was made on certain fuel types for specific industries and has been included in the Common Reporting Format (CRF) tables that are submitted to the UNFCCC along with this report.[6] However, a full mapping was not completed this year due to fuel category differences between national statistics published by EIA and facility-level reported GHGRP data. Furthermore, given that calendar year 2010 was the first year in which emissions data were reported to EPA's GHGRP, the current inventory's examination only focused on 2010, 2011and, 2012. For the current exercise, the efforts in reconciling fuels focused on standard, common fuel types (e.g., natural gas, distillate fuel oil, etc.) where the fuels in EIA's national statistics aligned well with facility-level GHGRP data. For these reasons, the current information presented in the CRF tables should be viewed as an initial attempt at this exercise. Additional efforts will be made for future inventory reports to improve the mapping of fuel types, and examine ways to reconcile and coordinate any differences between facility-level data and national statistics. Additionally, in order to expand this effort through the full time series presented in this report, further analyses will be conducted linking GHGRP facility-level reporting with the information published by EIA in its MECS data, other available MECS survey years , and any further informative sources of data. It is believed that the current analysis has led to improvements in the presentation of data in the Inventory, but further work will be conducted, and future improvements will be realized in subsequent Inventory reports.

Additionally, to assist in the disaggregation of industrial fuel consumption, EIA will now synthesize energy consumption data using the same procedure as is used for the last historical (benchmark) year of the Annual Energy Outlook (AEO). This procedure reorganizes the most recent data from the Manufacturing Energy Consumption Survey (MECS) (conducted every four years) into the nominal data submission year using the same energy-economy integrated model used to produce the AEO projections, the National Energy Modeling System (NEMS). EIA believes this "nowcasting" technique provides an appropriate estimate of energy consumption for the CRF.

To address gaps in the time series, EIA performs a NEMS model projection, using the MECS baseline sub-sector energy consumption. The NEMS model accounts for changes in factors that influence industrial sector energy consumption, and has access to data which may be more recent than MECS, such as industrial sub-sector macro industrial output (i.e., shipments) and fuel prices. By evaluating the impact of these factors on industrial subsector energy consumption, NEMS can anticipate changes to the energy shares occurring post-MECS and can provide a way to appropriately disaggregate the energy-related emissions data into the CRF.

While the fuel consumption values for the various manufacturing sub-sectors are not directly surveyed for all years, they represent EIA's best estimate of historical consumption values for non-MECS years. Moreover, as an integral part of each AEO publication, this synthetic data series is likely to be maintained consistent with all available EIA and non-EIA data sources even as the underlying data sources evolve for both manufacturing and non-manufacturing industries alike.

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[5] See Section 4 "Use of Facility-Level Data in Good Practice National Greenhouse Gas Inventories" of the IPCC meeting report, and specifically the section on using facility-level data in conjunction with energy data, at <http://www.ipcc-nggip.iges.or.jp/meeting/pdfiles/1008_Model_and_Facility_Level_Data_Report.pdf>.

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

Other sectors' fuel consumption (commercial, residential, transportation) will be benchmarked with the latest aggregate values from the Monthly Energy Review.[7] EIA will work with the U.S. Environmental Protection Agency to back cast these values to 1990.

[END BOX]

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[7] http://www.eia.gov/totalenergy/data/monthly/.

Table A- 10: 2012 Energy Consumption Data by Fuel Type (TBtu) and Adjusted Energy Consumption Data

1	2	3	4	5	6	7	8	9	10	11	12	13
	Total Consumption (TBtu)[a]							Adjustments (TBtu)[b]				
									Unadjusted NEU Consumption			
Fuel Type	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Bunker Fuel	Ind.	Trans.	Terr.	Total Adjusted Consumption
Total Coal	**NE**	**43.6**	**917.4**	**NE**	**15,821.2**	**36.9**	**16,819.0**		**132.7**			**16,686.3**
Residential Coal	NE											
Commercial Coal		43.6					43.6					43.6
Industrial Coking Coal			122.4				122.4		122.4			
Industrial Other Coal			795.0				795.0		10.3			784.7
Transportation Coal				NE			NE					
Electric Power Coal					15,821.2		15,821.2					15,821.2
U.S. Territory Coal (bit)						36.9	36.9					36.9
Natural Gas	**4,241.5**	**2,960.0**	**8,512.5**	**777.2**	**9,286.8**	**27.1**	**25,805.0**		**311.8**			**25,493.2**
Total Petroleum	**949.7**	**516.7**	**7,699.2**	**25,150.9**	**219.2**	**738.1**	**35,273.8**	**1,467.4**	**4,184.6**	**123.2**	**123.6**	**29,375.0**
Asphalt & Road Oil			826.7				826.7		826.7			
Aviation Gasoline				25.1			25.1					25.1
Distillate Fuel Oil	438.9	323.2	1,154.3	5,978.3	52.9	132.9	8,080.5	91.7	17.5			7,971.4
Jet Fuel				2,901.4	NA	56.4	2,957.8	916.3				2,041.5
Kerosene	7.7	1.2	2.0			7.2	18.2					18.2
LPG	503.1	145.5	2,229.4	33.7		11.9	2,923.7		2,003.9			919.8
Lubricants			130.5	123.2		1.0	254.8		130.5	123.2	1.0	
Motor Gasoline		15.0	86.9	15,418.6		242.3	15,762.8					15,762.8
Residual Fuel		31.4	7.0	670.5	76.7	163.8	949.4	459.5				490.0
Other Petroleum												
AvGas Blend Components			(0.0)				(0.0)					(0.0)
Crude Oil												
MoGas Blend Components												
Misc. Products			161.6			122.6	284.2		161.6		122.6	
Naphtha (<401 deg. F)			453.9				453.9		453.9			
Other Oil (>401 deg. F)			287.2				287.2		287.2			
Pentanes Plus			84.4				84.4		45.9			38.5
Petroleum Coke		0.4	704.3		89.6		794.3		66.3			728.0
Still Gas			1,480.8				1,480.8		161.1			1,319.8
Special Naphtha			14.7				14.7		14.7			
Unfinished Oils			60.1				60.1					60.1
Waxes			15.3				15.3		15.3			
Geothermal					**53.1**		**53.1**					**53.1**
TOTAL (All Fuels)	**5,191.3**	**3,520.2**	**17,129.0**	**25,928.1**	**25,380.3**	**802.1**	**77,951.0**	**1,467.4**	**4,629.1**	**123.2**	**123.6**	**71,607.7**

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

[b] Adjustments are subtracted from total consumption estimates and include biofuels, conversion of fossil fuels, non-energy use (see Table A-34), and international bunker fuel consumption (see Table A-35).

NE (Not Estimated)

NA (Not Available)

Table A- 11: 2012 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (Tg CO_2 Eq.) from Energy Use						
Fuel Type	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**
Total Coal	**NE**	**43.6**	**784.7**	**NE**	**15,821.2**	**36.9**	**16,686.3**	**NE**	**4.1**	**74.3**	**NE**	**1,511.2**	**3.4**	**1,593.0**
Residential Coal	NE							NE						
Commercial Coal		43.6					43.6		4.1					4.1
Industrial Other Coal			784.7				784.7			74.3				74.3
Transportation Coal				NE							NE			NE
Electric Power Coal					15,821.2		15,821.2					1,511.2		1,511.2
U.S. Territory Coal (bit)						36.9	36.9						3.4	3.4
Natural Gas	**4,241.5**	**2,960.0**	**8,200.7**	**777.2**	**9,286.8**	**27.1**	**25,493.2**	**224.8**	**156.9**	**434.7**	**41.2**	**492.2**	**1.4**	**1,351.2**
Total Petroleum	**949.7**	**516.7**	**3,514.6**	**23,560.3**	**219.2**	**614.4**	**29,375.0**	**64.1**	**36.4**	**265.2**	**1,698.3**	**18.8**	**44.7**	**2,127.6**
Asphalt & Road Oil														
Aviation Gasoline				25.1			25.1				1.7			1.7
Distillate Fuel Oil	438.9	323.2	1,136.8	5,886.7	52.9	132.9	7,971.4	32.5	23.9	84.1	435.4	3.9	9.8	589.5
Jet Fuel				1,985.2	NA	56.4	2,041.5				143.4		4.1	147.4
Kerosene	7.7	1.2	2.0			7.2	18.2	0.6	0.1	0.1			0.5	1.3
LPG	503.1	145.5	225.5	33.7		11.9	919.8	31.0	9.0	13.9	2.1		0.7	56.8
Lubricants														
Motor Gasoline		15.0	86.9	15,418.6		242.3	15,762.8		1.1	6.2	1,099.9		17.3	1,124.5
Residual Fuel		31.4	7.0	211.1	76.7	163.8	490.0		2.4	0.5	15.8	5.8	12.3	36.8
Other Petroleum														
AvGas Blend Components			(0.0)				(0.0)			(0.0)				(0.0)
Crude Oil														
MoGas Blend Components														
Misc. Products														
Naphtha (<401 deg. F)														
Other Oil (>401 deg. F)														
Pentanes Plus			38.5				38.5			2.7				2.7
Petroleum Coke		0.4	638.0		89.6		728.0		(0.0)	65.1		9.1		74.3
Still Gas			1,319.8				1,319.8			88.0				88.0
Special Naphtha														
Unfinished Oils			60.1				60.1			4.5				4.5
Waxes														
Geothermal					**53.1**		**53.1**					**0.4**		**0.4**
TOTAL (All Fuels)	**5,191.3**	**3,520.2**	**12,499.9**	**24,337.5**	**25,380.3**	**678.4**	**71,607.7**	**288.9**	**197.4**	**774.2**	**1,739.5**	**2,022.7**	**49.6**	**5,072.3**

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

[b] Adjustments are subtracted from total consumption estimates and include biofuels, conversion of fossil fuels, non-energy use (see Table A-34), and international bunker fuel consumption (see Table A-35).

NE (Not Estimated)

NA (Not Available)

Table A- 12: 2011 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (Tg CO_2 Eq.) from Energy Use						
Fuel Type	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**
Total Coal	**NE**	**61.7**	**866.1**	**NE**	**18,035.2**	**36.9**	**18,999.9**	**NE**	**5.8**	**82.0**	**NE**	**1,722.7**	**3.4**	**1,813.9**
Residential Coal	NE							NE						
Commercial Coal		61.7					61.7		5.8					5.8
Industrial Other Coal			866.1				866.1			82.0				82.0
Transportation Coal				NE							NE			NE
Electric Power Coal					18,035.2		18,035.2					1,722.7		1,722.7
U.S. Territory Coal (bit)						36.9	36.9						3.4	3.4
Natural Gas	**4,804.6**	**3,216.1**	**7,873.4**	**733.5**	**7,712.2**	**27.1**	**24,366.9**	**254.7**	**170.5**	**417.3**	**38.9**	**408.8**	**1.4**	**1,291.5**
Total Petroleum	**1,031.8**	**635.1**	**3,583.1**	**23,706.1**	**303.0**	**614.4**	**29,873.5**	**70.3**	**45.2**	**269.4**	**1,709.0**	**26.6**	**44.7**	**2,165.3**
Asphalt & Road Oil														
Aviation Gasoline				27.1			27.1				1.9			1.9
Distillate Fuel Oil	521.9	414.2	1,213.2	5,899.3	64.2	132.9	8,245.7	38.6	30.6	89.7	436.3	4.7	9.8	609.8
Jet Fuel				2,029.9	NA	56.4	2,086.3				146.6		4.1	150.7
Kerosene	18.5	3.2	3.6			7.2	32.5	1.4	0.2	0.3			0.5	2.4
LPG	491.3	142.1	176.5	32.9		11.9	854.8	30.3	8.8	10.9	2.0		0.7	52.8
Lubricants														
Motor Gasoline		21.6	125.0	15,459.0		242.2	15,847.8		1.5	8.9	1,102.8		17.3	1,130.6
Residual Fuel		53.7	72.1	258.0	93.1	163.8	640.6		4.0	5.4	19.4	7.0	12.3	48.1
Other Petroleum														
AvGas Blend Components			0.0				0.0			0.0				0.0
Crude Oil														
MoGas Blend Components														
Misc. Products														
Naphtha (<401 deg. F)														
Other Oil (>401 deg. F)														
Pentanes Plus			27.3				27.3			1.9				1.9
Petroleum Coke		0.2	585.9		145.7		731.8		0.0	59.8		14.9		74.7
Still Gas			1,323.4				1,323.4			88.3				88.3
Special Naphtha														
Unfinished Oils			56.1				56.1			4.2				4.2
Waxes														
Geothermal					**52.3**		**52.3**					**0.4**		**0.4**
TOTAL (All Fuels)	**5,836.3**	**3,912.9**	**12,322.6**	**24,439.7**	**26,102.6**	**678.3**	**73,292.5**	**324.9**	**221.5**	**768.7**	**1,747.9**	**2,158.5**	**49.6**	**5,271.1**

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

[b] Adjustments are subtracted from total consumption estimates and include biofuels, conversion of fossil fuels, non-energy use (see Table A-34), and international bunker fuel consumption (see Table A-35).

NE (Not Estimated)

NA (Not Available)

Table A- 13: 2010 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (Tg CO_2 Eq.) from Energy Use						
Fuel Type	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**
Total Coal	**NE**	**69.7**	**951.6**	**NE**	**19,133.5**	**36.9**	**20,191.6**	**NE**	**6.6**	**90.1**	**NE**	**1,827.6**	**3.4**	**1,927.7**
Residential Coal	NE							NE						
Commercial Coal		69.7					69.7		6.6					6.6
Industrial Other Coal			951.6				951.6			90.1				90.1
Transportation Coal				NE							NE			NE
Electric Power Coal					19,133.5		19,133.5					1,827.6		1,827.6
U.S. Territory Coal (bit)						36.9	36.9						3.4	3.4
Natural Gas	**4,878.1**	**3,164.7**	**7,683.2**	**719.0**	**7,527.6**	**27.8**	**24,000.4**	**258.6**	**167.7**	**407.2**	**38.1**	**399.0**	**1.5**	**1,272.1**
Total Petroleum	**1,119.5**	**650.9**	**3,704.1**	**23,960.2**	**378.3**	**614.4**	**30,427.2**	**76.3**	**46.4**	**278.3**	**1,726.9**	**32.2**	**44.7**	**2,204.8**
Asphalt & Road Oil														
Aviation Gasoline				27.0			27.0				1.9			1.9
Distillate Fuel Oil	560.2	394.4	1,121.4	5,765.5	80.3	132.9	8,054.7	41.4	29.2	82.9	426.4	5.9	9.8	595.7
Jet Fuel				2,097.5	NA	56.4	2,153.8				151.5		4.1	155.6
Kerosene	29.1	4.8	7.3			7.2	48.5	2.1	0.4	0.5			0.5	3.5
LPG	530.1	140.1	219.7	29.5		11.9	931.3	32.7	8.6	13.6	1.8		0.7	57.5
Lubricants														
Motor Gasoline		49.5	247.9	15,768.5		242.2	16,308.1		3.5	17.7	1,124.9		17.3	1,163.4
Residual Fuel		61.7	57.3	272.2	154.1	163.8	709.0		4.6	4.3	20.4	11.6	12.3	53.2
Other Petroleum														
AvGas Blend Components			(0.2)				(0.2)			(0.0)				(0.0)
Crude Oil														
MoGas Blend Components														
Misc. Products														
Naphtha (<401 deg. F)														
Other Oil (>401 deg. F)														
Pentanes Plus			77.8				77.8			5.4				5.4
Petroleum Coke		0.4	620.9		143.9		765.2		0.0	63.4		14.7		78.1
Still Gas			1,324.0				1,324.0			88.3				88.3
Special Naphtha														
Unfinished Oils			28.0				28.0			2.1				2.1
Waxes														
Geothermal					**51.9**		**51.9**					**0.4**		**0.4**
TOTAL (All Fuels)	**5,997.6**	**3,885.2**	**12,338.9**	**24,679.1**	**27,091.3**	**679.1**	**74,671.1**	**334.8**	**220.7**	**775.6**	**1,765.0**	**2,259.2**	**49.6**	**5,404.9**

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

[b] Adjustments are subtracted from total consumption estimates and include biofuels, conversion of fossil fuels, non-energy use (see Table A-34), and international bunker fuel consumption (see Table A-35).

NE (Not Estimated)

NA (Not Available)

Table A- 14: 2009 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (Tg CO_2 Eq.) from Energy Use						
Fuel Type	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**
Total Coal	**NE**	**73.4**	**877.3**	**NE**	**18,225.3**	**36.9**	**19,212.8**	**NE**	**6.9**	**83.0**	**NE**	**1,740.9**	**3.4**	**1,834.2**
Residential Coal	NE							NE						
Commercial Coal		73.4					73.4		6.9					6.9
Industrial Other Coal			877.3				877.3			83.0				83.0
Transportation Coal				NE							NE			NE
Electric Power Coal					18,225.3		18,225.3					1,740.9		1,740.9
U.S. Territory Coal (bit)						36.9	36.9						3.4	3.4
Natural Gas	**4,883.1**	**3,186.6**	**7,125.1**	**714.9**	**7,022.4**	**27.4**	**22,959.4**	**258.8**	**168.9**	**377.6**	**37.9**	**372.2**	**1.5**	**1,216.9**
Total Petroleum	**1,139.4**	**675.2**	**3,549.9**	**23,732.2**	**389.9**	**535.5**	**30,022.1**	**77.5**	**48.1**	**266.8**	**1,709.8**	**33.0**	**39.0**	**2,174.2**
Asphalt & Road Oil														
Aviation Gasoline				26.6			26.6				1.8			1.8
Distillate Fuel Oil	564.7	387.8	1,018.4	5,539.3	70.1	83.4	7,663.6	41.8	28.7	75.3	409.7	5.2	6.2	566.8
Jet Fuel				2,134.2	NA	61.5	2,195.7				154.1		4.4	158.6
Kerosene	27.7	4.2	4.4			8.0	44.3	2.0	0.3	0.3			0.6	3.2
LPG	547.1	138.9	201.7	28.0		15.0	930.7	33.8	8.6	12.4	1.7		0.9	57.4
Lubricants														
Motor Gasoline		72.8	333.8	15,818.3		202.0	16,426.9		5.2	23.8	1,128.5		14.4	1,171.9
Residual Fuel		71.3	67.3	185.7	181.0	165.7	670.9		5.4	5.1	13.9	13.6	12.4	50.4
Other Petroleum														
AvGas Blend Components			(0.8)				(0.8)			(0.1)				(0.1)
Crude Oil														
MoGas Blend Components														
Misc. Products														
Naphtha (<401 deg. F)														
Other Oil (>401 deg. F)														
Pentanes Plus			63.8				63.8			4.5				4.5
Petroleum Coke		0.3	618.0		138.9		757.2		0.0	63.1		14.2		77.3
Still Gas			1,321.1				1,321.1			88.1				88.1
Special Naphtha														
Unfinished Oils			(77.8)				(77.8)			(5.8)				(5.8)
Waxes														
Geothermal					**51.2**		**51.2**					**0.4**		**0.4**
TOTAL (All Fuels)	**6,022.5**	**3,935.1**	**11,552.2**	**24,447.0**	**25,688.9**	**599.8**	**72,245.6**	**336.4**	**223.9**	**727.5**	**1,747.7**	**2,146.4**	**43.8**	**5,225.7**

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

[b] Adjustments are subtracted from total consumption estimates and include biofuels, conversion of fossil fuels, non-energy use (see Table A-34), and international bunker fuel consumption (see Table A-35).

NE (Not Estimated)

NA (Not Available)

Table A-15: 2008 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (Tg CO_2 Eq.) from Energy Use						
Fuel Type	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**
Total Coal	**NE**	**80.8**	**1,081.5**	**NE**	**20,513.0**	**36.9**	**21,712.0**	**NE**	**7.6**	**102.4**	**NE**	**1,959.4**	**3.4**	**2,072.8**
Residential Coal	NE							NE						
Commercial Coal		80.8					80.8		7.6					7.6
Industrial Other Coal			1,081.5				1,081.5			102.4				102.4
Transportation Coal				NE							NE			NE
Electric Power Coal					20,513.0		20,513.0					1,959.4		1,959.4
U.S. Territory Coal (bit)						36.9	36.9						3.4	3.4
Natural Gas	**5,010.1**	**3,228.4**	**7,571.4**	**692.1**	**6,828.9**	**29.3**	**23,360.2**	**265.5**	**171.1**	**401.3**	**36.7**	**361.9**	**1.6**	**1,238.1**
Total Petroleum	**1,182.8**	**649.5**	**4,012.2**	**24,686.5**	**467.7**	**492.3**	**31,491.1**	**80.7**	**46.0**	**300.4**	**1,779.8**	**39.2**	**36.0**	**2,282.1**
Asphalt & Road Oil														
Aviation Gasoline				28.3			28.3				2.0			2.0
Distillate Fuel Oil	608.8	338.2	1,137.1	6,106.9	73.1	110.3	8,374.4	45.0	25.0	84.1	451.6	5.4	8.2	619.3
Jet Fuel				2,396.1	NA	35.0	2,431.1				173.0		2.5	175.6
Kerosene	21.3	4.4	3.8			5.9	35.4	1.6	0.3	0.3			0.4	2.6
LPG	552.7	158.0	226.7	40.1		15.7	993.3	34.1	9.7	14.0	2.5		1.0	61.3
Lubricants														
Motor Gasoline		77.7	424.5	15,843.9		136.1	16,482.1		5.5	30.3	1,130.3		9.7	1,175.8
Residual Fuel		71.0	131.5	271.3	240.4	189.3	903.5		5.3	9.9	20.4	18.1	14.2	67.8
Other Petroleum														
AvGas Blend Components			0.1				0.1			0.0				0.0
Crude Oil														
MoGas Blend Components														
Misc. Products														
Naphtha (<401 deg. F)														
Other Oil (>401 deg. F)														
Pentanes Plus			76.5				76.5			5.4				5.4
Petroleum Coke		0.3	642.6		154.2		797.1		0.0	65.6		15.7		81.4
Still Gas			1,423.0				1,423.0			94.9				94.9
Special Naphtha														
Unfinished Oils			(53.7)				(53.7)			(4.0)				(4.0)
Waxes														
Geothermal					**50.6**		**50.6**					**0.4**		**0.4**
TOTAL (All Fuels)	**6,192.9**	**3,958.7**	**12,665.0**	**25,378.7**	**27,860.2**	**558.4**	**76,613.9**	**346.2**	**224.7**	**804.1**	**1,816.5**	**2,360.9**	**41.0**	**5,593.4**

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

[b] Adjustments are subtracted from total consumption estimates and include biofuels, conversion of fossil fuels, non-energy use (seeTable A-34), and international bunker fuel consumption (see Table A-35).

NE (Not Estimated)

NA (Not Available)

Table A-16: 2007 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (Tg CO_2 Eq.) from Energy Use						
Fuel Type	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**
Total Coal	**7.8**	**70.0**	**1,130.8**	**NE**	**20,807.7**	**36.9**	**22,053.2**	**0.7**	**6.7**	**107.0**	**NE**	**1,987.3**	**3.4**	**2,105.1**
Residential Coal	7.8						7.8	0.7						0.7
Commercial Coal		70.0					70.0		6.7					6.7
Industrial Other Coal			1,130.8				1,130.8			107.0				107.0
Transportation Coal				NE							NE			NE
Electric Power Coal					20,807.7		20,807.7					1,987.3		1,987.3
U.S. Territory Coal (bit)						36.9	36.9						3.4	3.4
Natural Gas	**4,835.4**	**3,085.1**	**7,521.3**	**663.5**	**7,005.2**	**26.7**	**23,137.2**	**256.3**	**163.5**	**398.6**	**35.2**	**371.3**	**1.4**	**1,226.3**
Total Petroleum	**1,224.9**	**680.6**	**4,580.8**	**25,834.8**	**657.1**	**551.7**	**33,529.9**	**84.6**	**48.7**	**341.9**	**1,869.5**	**53.9**	**40.4**	**2,438.9**
Asphalt & Road Oil														
Aviation Gasoline				31.6			31.6				2.2			2.2
Distillate Fuel Oil	697.3	368.7	1,185.5	6,439.7	89.3	136.5	8,917.0	51.6	27.3	87.7	476.3	6.6	10.1	659.5
Jet Fuel				2,485.0	NA	55.5	2,540.4				179.5		4.0	183.5
Kerosene	43.9	9.2	13.4			5.2	71.8	3.2	0.7	1.0			0.4	5.3
LPG	483.7	121.4	379.1	21.9		11.6	1,017.7	29.8	7.5	23.4	1.4		0.7	62.8
Lubricants														
Motor Gasoline		105.6	528.4	16,470.5		157.0	17,261.4		7.6	37.9	1,181.2		11.3	1,238.0
Residual Fuel		75.4	130.4	386.1	396.6	185.9	1,174.4		5.7	9.8	29.0	29.8	14.0	88.2
Other Petroleum														
AvGas Blend Components			1.8				1.8			0.1				0.1
Crude Oil														
MoGas Blend Components														
Misc. Products														
Naphtha (<401 deg. F)														
Other Oil (>401 deg. F)														
Pentanes Plus			89.7				89.7			6.3				6.3
Petroleum Coke		0.4	704.7		171.2		876.3		0.0	72.0		17.5		89.5
Still Gas			1,482.6				1,482.6			98.9				98.9
Special Naphtha														
Unfinished Oils			65.2				65.2			4.8				4.8
Waxes														
Geothermal					**49.9**		**49.9**					**0.4**		**0.4**
TOTAL (All Fuels)	**6,068.1**	**3,835.7**	**13,232.9**	**26,498.2**	**28,520.0**	**615.3**	**78,770.2**	**341.6**	**218.9**	**847.5**	**1,904.7**	**2,412.8**	**45.2**	**5,770.8**

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-34), and international bunker fuel consumption (see Table A-35).

[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.

NE (Not Estimated)

NA (Not Available)

Table A-17: 2006 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (Tg CO_2 Eq.) from Energy Use						
Fuel Type	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**
Total Coal	**6.4**	**64.8**	**1,188.8**	**NE**	**20,461.9**	**36.9**	**21,758.7**	**0.6**	**6.2**	**112.6**	**NE**	**1,953.7**	**3.4**	**2,076.6**
Residential Coal	6.4						6.4	0.6						0.6
Commercial Coal		64.8					64.8		6.2					6.2
Industrial Other Coal			1,188.8				1,188.8			112.6				112.6
Transportation Coal				NE							NE			NE
Electric Power Coal					20,461.9		20,461.9					1,953.7		1,953.7
U.S. Territory Coal (bit)						36.9	36.9						3.4	3.4
Natural Gas	**4,475.9**	**2,901.7**	**7,323.2**	**625.0**	**6,375.1**	**26.1**	**21,727.0**	**237.3**	**153.8**	**388.2**	**33.1**	**338.0**	**1.4**	**1,151.8**
Total Petroleum	**1,204.9**	**677.7**	**4,699.4**	**25,766.7**	**648.1**	**620.9**	**33,617.7**	**83.6**	**48.5**	**350.9**	**1,857.8**	**54.4**	**45.5**	**2,440.7**
Asphalt & Road Oil														
Aviation Gasoline				33.4			33.4				2.3			2.3
Distillate Fuel Oil	693.0	390.5	1,199.4	6,358.6	73.7	90.2	8,805.3	51.3	28.9	88.7	470.3	5.4	6.7	651.2
Jet Fuel				2,523.8	NA	76.1	2,599.9				182.3		5.5	187.8
Kerosene	66.4	15.2	29.6			4.4	115.5	4.9	1.1	2.2			0.3	8.5
LPG	445.5	123.2	369.7	27.5		6.6	972.5	27.5	7.6	22.8	1.7		0.4	60.0
Lubricants														
Motor Gasoline		73.3	566.7	16,517.0		188.8	17,345.9		5.2	40.4	1,178.2		13.5	1,237.4
Residual Fuel		75.3	176.4	306.3	360.5	254.8	1,173.3		5.7	13.2	23.0	27.1	19.1	88.1
Other Petroleum														
AvGas Blend Components			0.6				0.6			0.0				0.0
Crude Oil														
MoGas Blend Components														
Misc. Products														
Naphtha (<401 deg. F)														
Other Oil (>401 deg. F)														
Pentanes Plus			70.0				70.0			4.9				4.9
Petroleum Coke		0.3	720.5		213.9		934.6		0.0	73.6		21.8		95.4
Still Gas			1,496.2				1,496.2			99.8				99.8
Special Naphtha														
Unfinished Oils			70.3				70.3			5.2				5.2
Waxes														
Geothermal					**49.7**		**49.7**					**0.4**		**0.4**
TOTAL (All Fuels)	**5,687.2**	**3,644.2**	**13,211.4**	**26,391.7**	**27,534.8**	**683.9**	**77,153.2**	**321.5**	**208.6**	**851.8**	**1,890.9**	**2,346.4**	**50.3**	**5,669.5**

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-34), and international bunker fuel consumption (see Table A-35).

[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.

NE (Not Estimated)

NA (Not Available)

Table A-18: 2005 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (Tg CO_2 Eq.) from Energy Use						
Fuel Type	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**
Total Coal	**8.4**	**97.0**	**1,219.1**	**NE**	**20,737.2**	**32.7**	**22,094.5**	**0.8**	**9.3**	**115.3**	**NE**	**1,983.8**	**3.0**	**2,112.3**
Residential Coal	8.4						8.4	0.8						0.8
Commercial Coal		97.0					97.0		9.3					9.3
Industrial Other Coal			1,219.1				1,219.1			115.3				115.3
Transportation Coal				NE							NE			NE
Electric Power Coal					20,737.2		20,737.2					1,983.8		1,983.8
U.S. Territory Coal (bit)						32.7	32.7						3.0	3.0
Natural Gas	**4,946.4**	**3,073.2**	**7,329.7**	**623.9**	**6,014.5**	**24.3**	**22,012.0**	**262.2**	**162.9**	**388.5**	**33.1**	**318.8**	**1.3**	**1,166.7**
Total Petroleum	**1,369.2**	**716.0**	**4,324.0**	**25,865.2**	**1,234.5**	**623.2**	**34,132.2**	**94.9**	**51.3**	**323.8**	**1,858.7**	**99.2**	**45.7**	**2,473.5**
Asphalt & Road Oil														
Aviation Gasoline				35.4			35.4				2.4			2.4
Distillate Fuel Oil	772.6	404.7	1,128.9	6,193.8	114.6	121.3	8,735.9	57.1	29.9	83.5	458.1	8.5	9.0	646.1
Jet Fuel				2,621.7	NA	66.0	2,687.7				189.3		4.8	194.1
Kerosene	83.8	21.6	39.1			5.8	150.2	6.1	1.6	2.9			0.4	11.0
LPG	512.9	131.4	349.6	28.2		0.8	1,022.8	31.7	8.1	21.6	1.7		0.0	63.1
Lubricants														
Motor Gasoline		42.2	328.2	16,729.7		194.2	17,294.3		3.0	23.3	1,187.8		13.8	1,227.9
Residual Fuel		115.8	237.4	256.4	876.5	235.2	1,721.3		8.7	17.8	19.3	65.8	17.7	129.3
Other Petroleum														
AvGas Blend Components			8.3				8.3			0.6				0.6
Crude Oil														
MoGas Blend Components														
Misc. Products														
Naphtha (<401 deg. F)														
Other Oil (>401 deg. F)														
Pentanes Plus			98.1				98.1			6.9				6.9
Petroleum Coke		0.3	702.1		243.5		945.9		0.0	71.7		24.9		96.6
Still Gas			1,429.4				1,429.4			95.4				95.4
Special Naphtha														
Unfinished Oils			2.8				2.8			0.2				0.2
Waxes														
Geothermal					**50.1**		**50.1**					**0.4**		**0.4**
TOTAL (All Fuels)	**6,324.0**	**3,886.2**	**12,872.8**	**26,489.1**	**28,036.4**	**680.2**	**78,288.9**	**357.9**	**223.5**	**827.6**	**1,891.7**	**2,402.1**	**50.0**	**5,752.9**

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-34), and international bunker fuel consumption (see Table A-35).

[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.

NE (Not Estimated)

NA (Not Available)

Table A-19: 2004 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (Tg CO_2 Eq.) from Energy Use						
Fuel Type	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**
Total Coal	**11.4**	**102.9**	**1,262.0**	**NE**	**20,305.0**	**32.0**	**21,713.3**	**1.1**	**9.8**	**118.3**	**NE**	**1,943.1**	**2.9**	**2,075.1**
Residential Coal	11.4						11.4	1.1						1.1
Commercial Coal		102.9					102.9		9.8					9.8
Industrial Other Coal			1,262.0				1,262.0			118.3				118.3
Transportation Coal				NE							NE			NE
Electric Power Coal					20,305.0		20,305.0					1,943.1		1,943.1
U.S. Territory Coal (bit)						32.0	32.0						2.9	2.9
Natural Gas	**4,980.8**	**3,201.0**	**7,913.5**	**602.0**	**5,594.9**	**24.6**	**22,316.9**	**264.1**	**169.7**	**419.6**	**31.9**	**296.7**	**1.3**	**1,183.4**
Total Petroleum	**1,474.6**	**766.7**	**4,193.3**	**25,589.7**	**1,212.4**	**653.6**	**33,890.2**	**102.7**	**54.9**	**314.1**	**1,839.2**	**96.9**	**47.9**	**2,455.8**
Asphalt & Road Oil														
Aviation Gasoline				31.2			31.2				2.2			2.2
Distillate Fuel Oil	878.1	447.0	1,139.6	5,917.7	111.3	134.4	8,628.1	64.9	33.1	84.3	437.7	8.2	9.9	638.1
Jet Fuel				2,584.8	NA	68.8	2,653.6				186.7		5.0	191.6
Kerosene	84.8	20.5	28.2			6.0	139.5	6.2	1.5	2.1			0.4	10.2
LPG	511.7	152.0	372.7	19.1		0.8	1,056.3	31.6	9.4	23.0	1.2		0.0	65.2
Lubricants														
Motor Gasoline		24.4	203.2	16,850.4		198.6	17,276.7		1.7	14.4	1,197.6		14.1	1,227.9
Residual Fuel		122.5	204.7	186.4	879.0	245.0	1,637.6		9.2	15.4	14.0	66.0	18.4	123.0
Other Petroleum														
AvGas Blend Components			10.6				10.6			0.7				0.7
Crude Oil														
MoGas Blend Components														
Misc. Products														
Naphtha (<401 deg. F)														
Other Oil (>401 deg. F)														
Pentanes Plus			111.2				111.2			7.8				7.8
Petroleum Coke		0.3	715.3		222.1		937.6		0.0	73.0		22.7		95.7
Still Gas			1,483.3				1,483.3			99.0				99.0
Special Naphtha														
Unfinished Oils			(75.6)				(75.6)			(5.6)				(5.6)
Waxes														
Geothermal					**50.5**		**50.5**					**0.4**		**0.4**
TOTAL (All Fuels)	**6,466.9**	**4,070.6**	**13,368.8**	**26,191.7**	**27,162.9**	**710.2**	**77,971.0**	**367.9**	**234.4**	**851.9**	**1,871.2**	**2,337.0**	**52.2**	**5,714.7**

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-34), and international bunker fuel consumption (see Table A-35).

[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.

NE (Not Estimated)

NA (Not Available)

Table A-20: 2003 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (Tg CO_2 Eq.) from Energy Use						
Fuel Type	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	**12.2**	**82.0**	**1,248.8**	**NE**	**20,184.7**	**33.9**	**21,561.7**	**1.2**	**7.8**	**117.0**	**NE**	**1,931.0**	**3.1**	**2,060.1**
Residential Coal	12.2						12.2	1.2						1.2
Commercial Coal		82.0					82.0		7.8					7.8
Industrial Other Coal			1,248.8				1,248.8			117.0				117.0
Transportation Coal				NE							NE			NE
Electric Power Coal					20,184.7		20,184.7					1,931.0		1,931.0
U.S. Territory Coal (bit)						33.9	33.9						3.1	3.1
Natural Gas	**5,209.4**	**3,260.9**	**7,845.1**	**627.4**	**5,246.2**	**26.9**	**22,216.0**	**275.9**	**172.7**	**415.4**	**33.2**	**277.8**	**1.4**	**1,176.4**
Total Petroleum	**1,466.1**	**762.0**	**3,948.6**	**24,940.9**	**1,205.0**	**621.8**	**32,944.5**	**101.8**	**54.5**	**296.5**	**1,790.6**	**95.0**	**45.3**	**2,383.7**
Asphalt & Road Oil														
Aviation Gasoline				30.2			30.2				2.1			2.1
Distillate Fuel Oil	851.3	453.1	1,055.5	5,710.9	161.0	120.5	8,352.3	63.0	33.5	78.1	422.4	11.9	8.9	617.7
Jet Fuel				2,482.5	NA	76.1	2,558.5				179.3		5.5	184.8
Kerosene	70.3	18.6	24.1			10.7	123.7	5.1	1.4	1.8			0.8	9.1
LPG	544.5	156.9	326.8	17.9		10.5	1,056.6	33.7	9.7	20.2	1.1		0.7	65.3
Lubricants														
Motor Gasoline		22.0	119.1	16,600.4		210.1	16,951.6		1.6	8.5	1,178.3		14.9	1,203.2
Residual Fuel		111.1	176.4	99.1	869.4	193.9	1,450.0		8.3	13.2	7.4	65.3	14.6	108.9
Other Petroleum														
AvGas Blend Components			7.5				7.5			0.5				0.5
Crude Oil														
MoGas Blend Components														
Misc. Products														
Naphtha (<401 deg. F)														
Other Oil (>401 deg. F)														
Pentanes Plus			110.4				110.4			7.7				7.7
Petroleum Coke		0.3	701.9		174.7		876.8		0.0	71.7		17.8		89.5
Still Gas			1,477.3				1,477.3			98.6				98.6
Special Naphtha														
Unfinished Oils			(50.4)				(50.4)			(3.7)				(3.7)
Waxes														
Geothermal					**49.2**		**49.2**					**0.4**		**0.4**
TOTAL (All Fuels)	**6,687.8**	**4,104.9**	**13,042.5**	**25,568.4**	**26,685.2**	**682.6**	**76,771.4**	**378.8**	**235.0**	**828.9**	**1,823.8**	**2,304.2**	**49.9**	**5,620.5**

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-34), and international bunker fuel consumption (see Table A-35).

[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.

NE (Not Estimated)

NA (Not Available)

Table A-21: 2002 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (Tg CO_2 Eq.) from Energy Use						
Fuel Type	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	**12.2**	**89.8**	**1,243.7**	**NE**	**19,782.8**	**10.8**	**21,139.3**	**1.2**	**8.6**	**116.6**	**NE**	**1,889.9**	**1.0**	**2,017.2**
Residential Coal	12.2						12.2	1.2						1.2
Commercial Coal		89.8					89.8		8.6					8.6
Industrial Other Coal			1,243.7				1,243.7			116.6				116.6
Transportation Coal				NE							NE			NE
Electric Power Coal					19,782.8		19,782.8					1,889.9		1,889.9
U.S. Territory Coal (bit)						10.8	10.8						1.0	1.0
Natural Gas	**4,995.0**	**3,212.5**	**8,086.3**	**698.9**	**5,766.8**	**22.8**	**22,782.3**	**264.7**	**170.3**	**428.6**	**37.0**	**305.7**	**1.2**	**1,207.5**
Total Petroleum	**1,358.9**	**645.4**	**3,785.2**	**24,961.1**	**961.3**	**556.8**	**32,268.7**	**93.9**	**46.1**	**283.9**	**1,793.6**	**76.8**	**40.6**	**2,334.9**
Asphalt & Road Oil														
Aviation Gasoline				33.7			33.7				2.3			2.3
Distillate Fuel Oil	761.8	393.4	1,048.4	5,595.9	127.4	92.8	8,019.7	56.3	29.1	77.5	413.9	9.4	6.9	593.1
Jet Fuel				2,565.5	NA	61.8	2,627.3				185.3		4.5	189.7
Kerosene	59.9	15.9	13.8			8.2	97.9	4.4	1.2	1.0			0.6	7.2
LPG	537.1	140.8	393.3	14.3		11.2	1,096.7	33.2	8.7	24.3	0.9		0.7	67.8
Lubricants														
Motor Gasoline		15.2	104.1	16,523.8		189.4	16,832.5		1.1	7.4	1,174.1		13.5	1,196.0
Residual Fuel		79.8	146.1	227.9	658.7	193.6	1,306.1		6.0	11.0	17.1	49.5	14.5	98.1
Other Petroleum														
AvGas Blend Components			7.5				7.5			0.5				0.5
Crude Oil														
MoGas Blend Components														
Misc. Products														
Naphtha (<401 deg. F)														
Other Oil (>401 deg. F)														
Pentanes Plus			111.9				111.9			7.8				7.8
Petroleum Coke		0.2	696.3		175.2		871.7		0.0	71.1		17.9		89.0
Still Gas			1,399.4				1,399.4			93.4				93.4
Special Naphtha														
Unfinished Oils			(135.7)				(135.7)			(10.1)				(10.1)
Waxes														
Geothermal					**49.4**		**49.4**					**0.4**		**0.4**
TOTAL (All Fuels)	**6,366.1**	**3,947.7**	**13,115.1**	**25,660.0**	**26,560.4**	**590.4**	**76,239.7**	**359.8**	**224.9**	**829.1**	**1,830.6**	**2,272.7**	**42.8**	**5,559.9**

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-34), and international bunker fuel consumption (see Table A-35).

[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.

NE (Not Estimated)

NA (Not Available)

Table A-22: 2001 Energy Consumption Data and CO$_2$ Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (Tg CO$_2$ Eq.) from Energy Use						
Fuel Type	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**
Total Coal	**12.0**	**96.9**	**1,358.4**	**NE**	**19,613.7**	**3.8**	**21,084.8**	**1.1**	**9.2**	**127.8**	**NE**	**1,869.8**	**0.4**	**2,008.4**
Residential Coal	12.0						12.0	1.1						1.1
Commercial Coal		96.9					96.9		9.2					9.2
Industrial Other Coal			1,358.4				1,358.4			127.8				127.8
Transportation Coal				NE							NE			NE
Electric Power Coal					19,613.7		19,613.7					1,869.8		1,869.8
U.S. Territory Coal (bit)						3.8	3.8						0.4	0.4
Natural Gas	**4,889.0**	**3,097.3**	**7,949.0**	**658.0**	**5,458.1**	**22.9**	**22,074.3**	**259.1**	**164.2**	**421.3**	**34.9**	**289.3**	**1.2**	**1,170.0**
Total Petroleum	**1,463.0**	**718.6**	**3,910.8**	**24,449.8**	**1,276.6**	**632.2**	**32,450.9**	**101.8**	**51.5**	**293.2**	**1,754.3**	**98.5**	**46.2**	**2,345.4**
Asphalt & Road Oil														
Aviation Gasoline				34.9			34.9				2.4			2.4
Distillate Fuel Oil	842.2	471.4	1,181.8	5,417.0	170.5	109.4	8,192.3	62.3	34.9	87.4	400.6	12.6	8.1	605.9
Jet Fuel				2,626.3	NA	98.9	2,725.2				189.7		7.1	196.8
Kerosene	95.1	31.4	23.2			0.9	150.6	7.0	2.3	1.7			0.1	11.0
LPG	525.7	142.7	372.1	13.7		7.0	1,061.2	32.5	8.8	23.0	0.8		0.4	65.6
Lubricants														
Motor Gasoline		3.1	24.2	16,198.3		187.6	16,413.2		0.2	1.7	1,148.7		13.3	1,164.0
Residual Fuel		69.9	146.7	159.5	1,002.8	228.4	1,607.2		5.2	11.0	12.0	75.3	17.2	120.7
Other Petroleum														
AvGas Blend Components			6.1				6.1			0.4				0.4
Crude Oil														
MoGas Blend Components														
Misc. Products														
Naphtha (<401 deg. F)														
Other Oil (>401 deg. F)														
Pentanes Plus			131.6				131.6			9.2				9.2
Petroleum Coke		0.2	683.3		103.2		786.7		0.0	69.8		10.5		80.3
Still Gas			1,417.3				1,417.3			94.6				94.6
Special Naphtha														
Unfinished Oils			(75.4)				(75.4)			(5.6)				(5.6)
Waxes														
Geothermal					**46.9**		**46.9**					**0.4**		**0.4**
TOTAL (All Fuels)	**6,364.0**	**3,912.7**	**13,218.2**	**25,107.8**	**26,395.2**	**658.9**	**75,656.8**	**362.0**	**224.9**	**842.3**	**1,789.2**	**2,257.9**	**47.8**	**5,524.1**

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-34), and international bunker fuel consumption (see Table A-35).

[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.

NE (Not Estimated)

NA (Not Available)

Table A-23: 2000 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (Tg CO_2 Eq.) from Energy Use						
Fuel Type	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**
Total Coal	**11.4**	**91.9**	**1,348.8**	**NE**	**20,220.2**	**10.3**	**21,682.4**	**1.1**	**8.8**	**127.3**	**NE**	**1,927.4**	**0.9**	**2,065.5**
Residential Coal	11.4						11.4	1.1						1.1
Commercial Coal		91.9					91.9		8.8					8.8
Industrial Other Coal			1,348.8				1,348.8			127.3				127.3
Transportation Coal				NE							NE			NE
Electric Power Coal					20,220.2		20,220.2					1,927.4		1,927.4
U.S. Territory Coal (bit)						10.3	10.3						0.9	0.9
Natural Gas	**5,104.6**	**3,251.5**	**8,656.0**	**672.0**	**5,293.4**	**12.7**	**22,990.2**	**270.7**	**172.5**	**459.1**	**35.6**	**280.8**	**0.7**	**1,219.4**
Total Petroleum	**1,427.5**	**694.0**	**3,575.0**	**24,649.1**	**1,144.3**	**471.7**	**31,961.5**	**98.8**	**49.6**	**267.5**	**1,769.1**	**88.4**	**34.2**	**2,307.6**
Asphalt & Road Oil														
Aviation Gasoline				36.3			36.3				2.5			2.5
Distillate Fuel Oil	778.0	422.2	1,003.7	5,442.4	174.8	71.3	7,892.5	57.5	31.2	74.2	402.5	12.9	5.3	583.7
Jet Fuel				2,700.3	NA	74.1	2,774.3				195.0		5.3	200.4
Kerosene	94.6	29.7	15.6			2.4	142.2	6.9	2.2	1.1			0.2	10.4
LPG	554.9	150.4	468.7	11.9		8.0	1,193.9	34.4	9.3	29.0	0.7		0.5	74.0
Lubricants														
Motor Gasoline				16,014.8		185.1	16,199.8				1,135.0		13.1	1,148.1
Residual Fuel		91.6	184.1	443.5	870.8	130.9	1,720.8		6.9	13.8	33.3	65.4	9.8	129.2
Other Petroleum														
AvGas Blend Components			3.8				3.8			0.3				0.3
Crude Oil														
MoGas Blend Components														
Misc. Products														
Naphtha (<401 deg. F)														
Other Oil (>401 deg. F)														
Pentanes Plus			171.6				171.6			12.0				12.0
Petroleum Coke		0.2	697.3		98.6		796.2		0.0	71.2		10.1		81.3
Still Gas			1,431.2				1,431.2			95.5				95.5
Special Naphtha														
Unfinished Oils			(401.2)				(401.2)			(29.7)				(29.7)
Waxes														
Geothermal					**48.1**		**48.1**					**0.4**		**0.4**
TOTAL (All Fuels)	**6,543.4**	**4,037.4**	**13,579.8**	**25,321.1**	**26,706.0**	**494.6**	**76,682.2**	**370.7**	**230.8**	**853.9**	**1,804.7**	**2,296.9**	**35.9**	**5,592.8**

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-34), and international bunker fuel consumption (see Table A-35).

[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.

NE (Not Estimated)

NA (Not Available)

Table A-24: 1999 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (Tg CO_2 Eq.) from Energy Use						
Fuel Type	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**
Total Coal	**14.0**	**102.5**	**1,372.8**	**NE**	**19,279.5**	**10.2**	**20,779.0**	**1.3**	**9.8**	**129.9**	**NE**	**1,836.4**	**0.9**	**1,978.3**
Residential Coal	14.0						14.0	1.3						1.3
Commercial Coal		102.5					102.5		9.8					9.8
Industrial Other Coal			1,372.8				1,372.8			129.9				129.9
Transportation Coal				NE							NE			NE
Electric Power Coal					19,279.5		19,279.5					1,836.4		1,836.4
U.S. Territory Coal (bit)						10.2	10.2						0.9	0.9
Natural Gas	**4,834.9**	**3,115.0**	**8,424.6**	**675.3**	**4,902.1**		**21,952.0**	**256.3**	**165.1**	**446.6**	**35.8**	**259.9**		**1,163.8**
Total Petroleum	**1,342.1**	**613.9**	**3,577.9**	**24,058.4**	**1,211.4**	**461.0**	**31,264.7**	**92.8**	**43.8**	**269.2**	**1,725.0**	**93.8**	**33.5**	**2,258.2**
Asphalt & Road Oil														
Aviation Gasoline				39.2			39.2				2.7			2.7
Distillate Fuel Oil	705.0	373.4	983.4	5,251.3	140.1	79.4	7,532.6	52.1	27.6	72.7	388.4	10.4	5.9	557.1
Jet Fuel				2,664.8	NA	59.5	2,724.4				192.5		4.3	196.8
Kerosene	111.2	26.9	12.8			3.7	154.7	8.1	2.0	0.9			0.3	11.3
LPG	526.0	140.2	395.9	14.3		8.3	1,084.6	32.5	8.7	24.5	0.9		0.5	67.1
Lubricants														
Motor Gasoline				15,913.1		164.0	16,077.2				1,127.4		11.6	1,139.0
Residual Fuel		73.3	150.9	175.7	958.7	146.0	1,504.6		5.5	11.3	13.2	72.0	11.0	113.0
Other Petroleum														
AvGas Blend Components			6.4				6.4			0.4				0.4
Crude Oil														
MoGas Blend Components														
Misc. Products														
Naphtha (<401 deg. F)														
Other Oil (>401 deg. F)														
Pentanes Plus			182.5				182.5			12.8				12.8
Petroleum Coke		0.1	719.8		112.5		832.4		0.0	73.5		11.5		85.0
Still Gas			1,414.1				1,414.1			94.3				94.3
Special Naphtha														
Unfinished Oils			(287.9)				(287.9)			(21.3)				(21.3)
Waxes														
Geothermal					**50.6**		**50.6**					**0.4**		**0.4**
TOTAL (All Fuels)	**6,191.0**	**3,831.5**	**13,375.3**	**24,733.8**	**25,443.6**	**471.2**	**74,046.3**	**350.5**	**218.7**	**845.7**	**1,760.8**	**2,190.5**	**34.5**	**5,400.7**

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-34), and international bunker fuel consumption (see Table A-35).

[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.

NE (Not Estimated)

NA (Not Available)

Table A-25: 1998 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (Tg CO_2 Eq.) from Energy Use						
Fuel Type	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**
Total Coal	**11.5**	**93.4**	**1,470.8**	**NE**	**19,215.7**	**10.5**	**20,802.0**	**1.1**	**8.9**	**139.1**	**NE**	**1,828.2**	**1.0**	**1,978.3**
Residential Coal	11.5						11.5	1.1						1.1
Commercial Coal		93.4					93.4		8.9					8.9
Industrial Other Coal			1,470.8				1,470.8			139.1				139.1
Transportation Coal				NE							NE			NE
Electric Power Coal					19,215.7		19,215.7					1,828.2		1,828.2
U.S. Territory Coal (bit)						10.5	10.5						1.0	1.0
Natural Gas	**4,646.1**	**3,083.0**	**8,826.0**	**666.1**	**4,674.9**		**21,896.1**	**246.0**	**163.3**	**467.4**	**35.3**	**247.6**		**1,159.5**
Total Petroleum	**1,207.3**	**609.1**	**3,470.7**	**23,278.6**	**1,306.2**	**445.4**	**30,317.4**	**84.0**	**43.7**	**262.4**	**1,670.9**	**101.3**	**32.4**	**2,194.7**
Asphalt & Road Oil														
Aviation Gasoline				35.5			35.5				2.5			2.5
Distillate Fuel Oil	675.1	375.1	1,027.9	4,955.2	135.7	71.9	7,240.8	49.9	27.7	76.0	366.5	10.0	5.3	535.5
Jet Fuel				2,608.0	NA	59.9	2,667.8				188.4		4.3	192.7
Kerosene	108.3	31.2	22.1			6.3	167.8	7.9	2.3	1.6			0.5	12.3
LPG	423.9	117.6	271.6	17.6		5.9	836.7	26.1	7.2	16.7	1.1		0.4	51.6
Lubricants														
Motor Gasoline				15,583.4		160.3	15,743.8				1,106.6		11.4	1,118.0
Residual Fuel		85.2	173.3	78.9	1,047.0	141.1	1,525.5		6.4	13.0	5.9	78.6	10.6	114.6
Other Petroleum														
AvGas Blend Components			4.0				4.0			0.3				0.3
Crude Oil														
MoGas Blend Components														
Misc. Products														
Naphtha (<401 deg. F)														
Other Oil (>401 deg. F)														
Pentanes Plus			147.0				147.0			10.3				10.3
Petroleum Coke		0.1	707.7		123.6		831.4		0.0	72.3		12.6		84.9
Still Gas			1,431.0				1,431.0			95.5				95.5
Special Naphtha														
Unfinished Oils			(313.9)				(313.9)			(23.3)				(23.3)
Waxes														
Geothermal					**50.4**		**50.4**					**0.4**		**0.4**
TOTAL (All Fuels)	**5,865.0**	**3,785.5**	**13,767.5**	**23,944.7**	**25,247.2**	**456.0**	**73,065.9**	**331.1**	**215.9**	**868.9**	**1,706.2**	**2,177.4**	**33.4**	**5,332.8**

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-34), and international bunker fuel consumption (see Table A-35).

[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.

NE (Not Estimated)

NA (Not Available)

Table A-26: 1997 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (Tg CO_2 Eq.) from Energy Use						
Fuel Type	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**
Total Coal	**16.0**	**129.4**	**1,457.6**	**NE**	**18,904.5**	**10.4**	**20,518.0**	**1.5**	**12.3**	**137.6**	**NE**	**1,797.0**	**1.0**	**1,949.5**
Residential Coal	16.0						16.0	1.5						1.5
Commercial Coal		129.4					129.4		12.3					12.3
Industrial Other Coal			1,457.6				1,457.6			137.6				137.6
Transportation Coal				NE							NE			NE
Electric Power Coal					18,904.5		18,904.5					1,797.0		1,797.0
U.S. Territory Coal (bit)						10.4	10.4						1.0	1.0
Natural Gas	**5,092.9**	**3,285.3**	**9,032.5**	**780.3**	**4,125.5**		**22,316.6**	**270.1**	**174.2**	**479.0**	**41.4**	**218.8**		**1,183.4**
Total Petroleum	**1,333.5**	**655.1**	**3,896.2**	**22,693.8**	**926.8**	**445.3**	**29,950.8**	**93.0**	**47.1**	**290.1**	**1,628.5**	**72.2**	**32.4**	**2,163.3**
Asphalt & Road Oil														
Aviation Gasoline				39.7			39.7				2.7			2.7
Distillate Fuel Oil	785.9	398.9	1,057.3	4,802.2	110.6	81.6	7,236.4	58.1	29.5	78.2	355.2	8.2	6.0	535.2
Jet Fuel				2,553.8	NA	62.1	2,615.9				184.4		4.5	188.9
Kerosene	92.9	24.6	18.8			4.0	140.3	6.8	1.8	1.4			0.3	10.3
LPG	454.8	120.2	429.9	14.2		6.5	1,025.7	28.1	7.4	26.5	0.9		0.4	63.3
Lubricants														
Motor Gasoline				15,147.5		160.0	15,307.5				1,075.0		11.4	1,086.4
Residual Fuel		111.2	240.1	136.5	714.6	131.1	1,333.5		8.4	18.0	10.3	53.7	9.8	100.1
Other Petroleum														
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														
Naphtha (<401 deg. F)														
Other Oil (>401 deg. F)														
Pentanes Plus			164.5				164.5			11.5				11.5
Petroleum Coke		0.1	639.9		101.6		741.6		0.0	65.3		10.4		75.7
Still Gas			1,435.0				1,435.0			95.7				95.7
Special Naphtha														
Unfinished Oils			(102.9)				(102.9)			(7.6)				(7.6)
Waxes														
Geothermal					**50.2**		**50.2**					**0.4**		**0.4**
TOTAL (All Fuels)	**6,442.5**	**4,069.8**	**14,386.4**	**23,474.1**	**24,007.1**	**455.7**	**72,835.6**	**364.6**	**233.6**	**906.7**	**1,669.8**	**2,088.4**	**33.4**	**5,296.5**

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-34), and international bunker fuel consumption (see Table A-35).

[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.

NE (Not Estimated)

NA (Not Available)

Table A-27: 1996 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							**Emissions[b] (Tg CO_2 Eq.) from Energy Use**						
Fuel Type	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**
Total Coal	**16.6**	**121.6**	**1,454.9**	**NE**	**18,429.0**	**10.3**	**20,032.4**	**1.6**	**11.6**	**137.4**	**NE**	**1,752.4**	**1.0**	**1,903.9**
Residential Coal	16.6						16.6	1.6						1.6
Commercial Coal		121.6					121.6		11.6					11.6
Industrial Other Coal			1,454.9				1,454.9			137.4				137.4
Transportation Coal				NE							NE			NE
Electric Power Coal					18,429.0		18,429.0					1,752.4		1,752.4
U.S. Territory Coal (bit)						10.3	10.3						1.0	1.0
Natural Gas	**5,354.4**	**3,226.3**	**9,020.3**	**736.9**	**3,862.4**		**22,200.4**	**283.9**	**171.1**	**478.3**	**39.1**	**204.8**		**1,177.2**
Total Petroleum	**1,396.6**	**718.3**	**3,912.3**	**22,502.3**	**817.4**	**434.6**	**29,781.4**	**97.5**	**51.8**	**291.5**	**1,615.0**	**63.4**	**31.6**	**2,150.7**
Asphalt & Road Oil														
Aviation Gasoline				37.4			37.4				2.6			2.6
Distillate Fuel Oil	839.0	437.6	1,049.1	4,599.0	109.4	76.5	7,110.5	62.1	32.4	77.6	340.1	8.1	5.7	525.9
Jet Fuel				2,556.0	NA	78.5	2,634.5				184.6		5.7	190.3
Kerosene	88.8	21.0	18.3			3.0	131.1	6.5	1.5	1.3			0.2	9.6
LPG	468.7	122.4	401.7	15.6		7.3	1,015.8	28.9	7.5	24.8	1.0		0.5	62.6
Lubricants														
Motor Gasoline				14,979.4		151.4	15,130.8				1,063.0		10.7	1,073.8
Residual Fuel		137.2	284.7	314.9	628.4	118.0	1,483.1		10.3	21.4	23.6	47.2	8.9	111.4
Other Petroleum														
AvGas Blend Components			7.0				7.0			0.5				0.5
Crude Oil			13.7				13.7			1.0				1.0
MoGas Blend Components														
Misc. Products														
Naphtha (<401 deg. F)														
Other Oil (>401 deg. F)														
Pentanes Plus			177.5				177.5			12.4				12.4
Petroleum Coke		0.1	638.2		79.6		717.9		0.0	65.2		8.1		73.3
Still Gas			1,434.9				1,434.9			95.7				95.7
Special Naphtha														
Unfinished Oils			(112.8)				(112.8)			(8.4)				(8.4)
Waxes														
Geothermal					**48.9**		**48.9**					**0.4**		**0.4**
TOTAL (All Fuels)	**6,767.5**	**4,066.2**	**14,387.5**	**23,239.2**	**23,157.7**	**445.0**	**72,063.1**	**383.0**	**234.5**	**907.2**	**1,654.0**	**2,021.0**	**32.5**	**5,232.2**

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-34), and international bunker fuel consumption (see Table A-35).

[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.

NE (Not Estimated)

NA (Not Available)

Table A-28: 1995 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (Tg CO_2 Eq.) from Energy Use						
Fuel Type	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**
Total Coal	**17.5**	**116.8**	**1,526.9**	**NE**	**17,466.3**	**10.2**	**19,137.7**	**1.7**	**11.2**	**144.4**	**NE**	**1,660.7**	**0.9**	**1,819.0**
Residential Coal	17.5						17.5	1.7						1.7
Commercial Coal		116.8					116.8		11.2					11.2
Industrial Other Coal			1,526.9				1,526.9			144.4				144.4
Transportation Coal				NE							NE			NE
Electric Power Coal					17,466.3		17,466.3					1,660.7		1,660.7
U.S. Territory Coal (bit)						10.2	10.2						0.9	0.9
Natural Gas	**4,954.2**	**3,096.0**	**8,722.5**	**724.0**	**4,302.0**		**21,798.6**	**262.7**	**164.2**	**462.5**	**38.4**	**228.1**		**1,155.9**
Total Petroleum	**1,260.9**	**694.0**	**3,538.2**	**21,935.2**	**754.6**	**461.8**	**28,644.7**	**88.3**	**50.1**	**263.2**	**1,571.2**	**58.7**	**33.6**	**2,065.1**
Asphalt & Road Oil														
Aviation Gasoline				39.6			39.6				2.7			2.7
Distillate Fuel Oil	791.8	419.1	967.9	4,383.3	108.1	89.5	6,759.6	58.6	31.0	71.6	324.2	8.0	6.6	499.9
Jet Fuel				2,428.8	NA	75.7	2,504.5				172.2		5.4	177.6
Kerosene	74.3	22.1	15.4			3.6	115.4	5.4	1.6	1.1			0.3	8.4
LPG	394.8	108.7	403.4	17.7		5.6	930.2	24.4	6.7	24.9	1.1		0.3	57.4
Lubricants														
Motor Gasoline		2.5	27.2	14,678.5		146.7	14,854.9		0.2	1.9	1,041.8		10.4	1,054.3
Residual Fuel		141.5	286.2	387.3	566.0	140.7	1,521.6		10.6	21.5	29.1	42.5	10.6	114.3
Other Petroleum														
AvGas Blend Components			5.3				5.3			0.4				0.4
Crude Oil			14.5				14.5			1.1				1.1
MoGas Blend Components														
Misc. Products														
Naphtha (<401 deg. F)														
Other Oil (>401 deg. F)														
Pentanes Plus			169.0				169.0			11.8				11.8
Petroleum Coke		0.1	600.7		80.6		681.4		0.0	61.3		8.2		69.6
Still Gas			1,369.5				1,369.5			91.4				91.4
Special Naphtha														
Unfinished Oils			(320.9)				(320.9)			(23.8)				(23.8)
Waxes														
Geothermal					**45.6**		**45.6**					**0.3**		**0.3**
Total Coal	**6,232.5**	**3,906.8**	**13,787.7**	**22,659.2**	**22,568.5**	**472.0**	**69,626.6**	**352.7**	**225.5**	**870.2**	**1,609.5**	**1,947.9**	**34.5**	**5,040.4**

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-34), and international bunker fuel consumption (see Table A-35).

[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.

NE (Not Estimated)

NA (Not Available)

Table A-29: 1994 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (Tg CO_2 Eq.) from Energy Use						
Fuel Type	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	**20.8**	**118.1**	**1,594.9**	**NE**	**17,260.9**	**10.0**	**19,004.7**	**2.0**	**11.3**	**150.7**	**NE**	**1,638.8**	**0.9**	**1,803.7**
Residential Coal	20.8						20.8	2.0						2.0
Commercial Coal		118.1					118.1		11.3					11.3
Industrial Other Coal			1,594.9				1,594.9			150.7				150.7
Transportation Coal				NE							NE			NE
Electric Power Coal					17,260.9		17,260.9					1,638.8		1,638.8
U.S. Territory Coal (bit)						10.0	10.0						0.9	0.9
Natural Gas	**4,959.8**	**2,962.0**	**8,290.3**	**708.5**	**3,977.3**		**20,897.9**	**262.9**	**157.0**	**439.4**	**37.6**	**210.8**		**1,107.6**
Total Petroleum	**1,305.3**	**745.9**	**3,697.9**	**21,492.3**	**1,058.8**	**506.3**	**28,806.5**	**91.8**	**54.0**	**274.6**	**1,539.3**	**81.3**	**36.9**	**2,077.9**
Asphalt & Road Oil														
Aviation Gasoline				38.1			38.1				2.6			2.6
Distillate Fuel Oil	856.7	447.1	975.8	4,187.0	120.1	118.8	6,705.5	63.4	33.1	72.2	309.7	8.9	8.8	495.9
Jet Fuel				2,473.8	NA	65.8	2,539.5				175.5		4.7	180.2
Kerosene	64.9	19.5	16.9			3.0	104.3	4.8	1.4	1.2			0.2	7.6
LPG	383.7	107.3	423.1	34.0		7.3	955.3	23.7	6.6	26.1	2.1		0.4	59.0
Lubricants														
Motor Gasoline				14,401.3		147.4	14,548.7				1,022.5		10.5	1,033.0
Residual Fuel		171.9	368.4	358.1	869.0	164.1	1,931.5		12.9	27.7	26.9	65.3	12.3	145.0
Other Petroleum														
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														
Naphtha (<401 deg. F)														
Other Oil (>401 deg. F)														
Pentanes Plus			169.4				169.4			11.9				11.9
Petroleum Coke		0.1	594.9		69.7		664.7		0.0	60.7		7.1		67.9
Still Gas			1,404.0				1,404.0			93.7				93.7
Special Naphtha														
Unfinished Oils			(279.2)				(279.2)			(20.7)				(20.7)
Waxes														
Geothermal					**53.0**		**53.0**					**0.4**		**0.4**
Total Coal	**6,286.0**	**3,826.0**	**13,583.1**	**22,200.8**	**22,350.0**	**516.3**	**68,762.2**	**356.7**	**222.3**	**864.7**	**1,576.9**	**1,931.2**	**37.8**	**4,989.6**

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-34), and international bunker fuel consumption (see Table A-35).

[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.

NE (Not Estimated)

NA (Not Available)

Table A-30: 1993 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (Tg CO_2 Eq.) from Energy Use						
Fuel Type	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**
Total Coal	**25.7**	**117.3**	**1,585.0**	**NE**	**17,195.9**	**9.6**	**18,933.5**	**2.5**	**11.3**	**149.8**	**NE**	**1,632.5**	**0.9**	**1,796.9**
Residential Coal	25.7						25.7	2.5						2.5
Commercial Coal		117.3					117.3		11.3					11.3
Industrial Other Coal			1,585.0				1,585.0			149.8				149.8
Transportation Coal				NE							NE			NE
Electric Power Coal					17,195.9		17,195.9					1,632.5		1,632.5
U.S. Territory Coal (bit)						9.6	9.6						0.9	0.9
Natural Gas	**5,063.3**	**2,923.3**	**8,272.5**	**644.7**	**3,537.5**		**20,441.3**	**268.4**	**155.0**	**438.6**	**34.2**	**187.5**		**1,083.7**
Total Petroleum	**1,348.5**	**743.4**	**3,588.7**	**20,921.0**	**1,123.8**	**459.9**	**28,185.1**	**94.9**	**53.8**	**267.4**	**1,502.1**	**86.4**	**33.6**	**2,038.2**
Asphalt & Road Oil														
Aviation Gasoline				38.4			38.4				2.7			2.7
Distillate Fuel Oil	883.3	447.2	989.9	3,889.4	86.5	104.9	6,401.1	65.3	33.1	73.2	287.6	6.4	7.8	473.4
Jet Fuel				2,368.4	NA	62.1	2,430.5				168.2		4.4	172.6
Kerosene	75.6	14.0	13.1			3.8	106.5	5.5	1.0	1.0			0.3	7.8
LPG	389.6	109.2	412.2	20.2		4.9	936.2	24.0	6.7	25.4	1.2		0.3	57.8
Lubricants														
Motor Gasoline				14,237.0		128.3	14,365.3				1,014.8		9.1	1,023.9
Residual Fuel		172.7	382.9	367.5	958.6	155.9	2,037.7		13.0	28.8	27.6	72.0	11.7	153.0
Other Petroleum														
AvGas Blend Components			0.2				0.2			0.0				0.0
Crude Oil			21.2				21.2			1.6				1.6
MoGas Blend Components														
Misc. Products														
Naphtha (<401 deg. F)														
Other Oil (>401 deg. F)														
Pentanes Plus			166.1				166.1			11.6				11.6
Petroleum Coke		0.2	614.6		78.6		693.4		0.0	62.8		8.0		70.8
Still Gas			1,384.6				1,384.6			92.4				92.4
Special Naphtha														
Unfinished Oils			(396.0)				(396.0)			(29.3)				(29.3)
Waxes														
Geothermal					**57.3**		**57.3**					**0.4**		**0.4**
Total Coal	**6,437.5**	**3,783.9**	**13,446.1**	**21,565.7**	**21,914.5**	**469.5**	**67,617.2**	**365.8**	**220.1**	**855.7**	**1,536.3**	**1,906.9**	**34.5**	**4,919.2**

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-34), and international bunker fuel consumption (see Table A-35).

[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.

NE (Not Estimated)

NA (Not Available)

Table A-31: 1992 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (Tg CO_2 Eq.) from Energy Use						
Fuel Type	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	**25.6**	**116.6**	**1,554.6**	**NE**	**16,465.6**	**8.8**	**18,171.1**	**2.5**	**11.3**	**147.4**	**NE**	**1,569.6**	**0.8**	**1,731.6**
Residential Coal	25.6						25.6	2.5						2.5
Commercial Coal		116.6					116.6		11.3					11.3
Industrial Other Coal			1,554.6				1,554.6			147.4				147.4
Transportation Coal				NE							NE			NE
Electric Power Coal					16,465.6		16,465.6					1,569.6		1,569.6
U.S. Territory Coal (bit)						8.8	8.8						0.8	0.8
Natural Gas	**4,804.6**	**2,871.2**	**8,125.3**	**608.1**	**3,511.5**		**19,920.7**	**254.5**	**152.1**	**430.5**	**32.2**	**186.0**		**1,055.4**
Total Petroleum	**1,365.8**	**788.9**	**3,758.7**	**20,442.6**	**990.7**	**444.9**	**27,791.7**	**96.5**	**57.3**	**279.5**	**1,470.4**	**75.5**	**32.5**	**2,011.6**
Asphalt & Road Oil														
Aviation Gasoline				41.1			41.1				2.8			2.8
Distillate Fuel Oil	931.4	481.7	1,028.5	3,665.7	73.5	91.8	6,272.6	68.9	35.6	76.1	271.1	5.4	6.8	463.9
Jet Fuel				2,343.8	NA	61.3	2,405.1				166.6		4.4	171.0
Kerosene	65.0	11.1	9.8			3.3	89.2	4.8	0.8	0.7			0.2	6.5
LPG	369.4	106.9	441.8	19.4		11.9	949.4	22.8	6.6	27.3	1.2		0.7	58.7
Lubricants														
Motor Gasoline				13,972.5		122.1	14,094.7				998.6		8.7	1,007.4
Residual Fuel		189.1	323.9	400.1	872.2	154.6	1,939.8		14.2	24.3	30.0	65.5	11.6	145.7
Other Petroleum														
AvGas Blend Components			0.2				0.2			0.0				0.0
Crude Oil			27.4				27.4			2.0				2.0
MoGas Blend Components			75.7				75.7			5.4				5.4
Misc. Products														
Naphtha (<401 deg. F)														
Other Oil (>401 deg. F)														
Pentanes Plus			161.3				161.3			11.3				11.3
Petroleum Coke		0.1	626.7		45.0		671.8		0.0	64.0		4.6		68.6
Still Gas			1,418.4				1,418.4			94.6				94.6
Special Naphtha														
Unfinished Oils			(354.8)				(354.8)			(26.3)				(26.3)
Waxes														
Geothermal					**55.1**		**55.1**					**0.4**		**0.4**
Total Coal	**6,196.0**	**3,776.7**	**13,438.6**	**21,050.7**	**21,022.9**	**453.7**	**65,938.6**	**353.5**	**220.6**	**857.4**	**1,502.7**	**1,831.5**	**33.3**	**4,799.0**

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-34), and international bunker fuel consumption (see Table A-35).

[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.

NE (Not Estimated)

NA (Not Available)

Table A-32: 1991 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (Tg CO_2 Eq.) from Energy Use						
Fuel Type	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**
Total Coal	**25.4**	**115.5**	**1,602.7**	**NE**	**16,249.7**	**7.7**	**18,001.0**	**2.4**	**11.1**	**152.1**	**NE**	**1,548.2**	**0.7**	**1,714.6**
Residential Coal	25.4						25.4	2.4						2.4
Commercial Coal		115.5					115.5		11.1					11.1
Industrial Other Coal			1,602.7				1,602.7			152.1				152.1
Transportation Coal				NE							NE			NE
Electric Power Coal					16,249.7		16,249.7					1,548.2		1,548.2
U.S. Territory Coal (bit)						7.7	7.7						0.7	0.7
Natural Gas	**4,667.2**	**2,795.4**	**7,827.8**	**620.3**	**3,377.4**		**19,288.1**	**247.3**	**148.1**	**414.7**	**32.9**	**178.9**		**1,021.8**
Total Petroleum	**1,381.5**	**903.6**	**3,480.5**	**19,715.8**	**1,198.3**	**425.4**	**27,105.1**	**97.5**	**65.6**	**259.2**	**1,414.7**	**90.7**	**30.9**	**1,958.6**
Asphalt & Road Oil														
Aviation Gasoline				41.7			41.7				2.9			2.9
Distillate Fuel Oil	931.0	517.7	1,050.8	3,449.7	83.6	71.4	6,104.1	68.9	38.3	77.7	255.1	6.2	5.3	451.4
Jet Fuel				2,373.6	NA	78.2	2,451.8				168.8		5.6	174.4
Kerosene	72.3	12.1	11.4			2.8	98.6	5.3	0.9	0.8			0.2	7.2
LPG	378.1	108.2	342.2	21.1		13.8	863.5	23.3	6.7	21.1	1.3		0.9	53.3
Lubricants														
Motor Gasoline		53.7	122.0	13,605.3		124.7	13,905.6		3.8	8.7	969.7		8.9	991.1
Residual Fuel		211.9	270.9	224.4	1,085.3	134.6	1,927.2		15.9	20.3	16.9	81.5	10.1	144.7
Other Petroleum														
AvGas Blend Components			(0.1)				(0.1)			(0.0)				(0.0)
Crude Oil			39.0				39.0			2.9				2.9
MoGas Blend Components			(25.9)				(25.9)			(1.8)				(1.8)
Misc. Products														
Naphtha (<401 deg. F)														
Other Oil (>401 deg. F)														
Pentanes Plus			147.0				147.0			10.3				10.3
Petroleum Coke			587.6		29.3		616.9			60.0		3.0		63.0
Still Gas			1,385.9				1,385.9			92.5				92.5
Special Naphtha														
Unfinished Oils			(450.2)				(450.2)			(33.3)				(33.3)
Waxes														
Geothermal					**54.5**		**54.5**					**0.4**		**0.4**
Total Coal	**6,074.0**	**3,814.5**	**12,911.1**	**20,336.1**	**20,879.8**	**433.2**	**64,448.7**	**347.2**	**224.8**	**826.0**	**1,447.6**	**1,818.2**	**31.6**	**4,695.4**

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-34), and international bunker fuel consumption (see Table A-35).

[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.

NE (Not Estimated)

NA (Not Available)

Table A- 33: 1990 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							**Emissions[b] (Tg CO_2 Eq.) from Energy Use**						
Fuel Type	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**	**Res.**	**Comm.**	**Ind.**	**Trans.**	**Elec.**	**Terr.**	**Total**
Total Coal	**31.1**	**124.5**	**1,640.5**	**NE**	**16,261.0**	**7.0**	**18,064.0**	**3.0**	**12.0**	**155.3**	**NE**	**1,547.6**	**0.6**	**1,718.4**
Residential Coal	31.1						31.1	3.0						3.0
Commercial Coal		124.5					124.5		12.0					12.0
Industrial Other Coal			1,640.5				1,640.5			155.3				155.3
Transportation Coal				NE							NE			NE
Electric Power Coal					16,261.0		16,261.0					1,547.6		1,547.6
U.S. Territory Coal (bit)						7.0	7.0						0.6	0.6
Natural Gas	**4,490.9**	**2,682.2**	**7,716.4**	**679.9**	**3,308.5**		**18,877.9**	**238.0**	**142.1**	**408.9**	**36.0**	**175.3**		**1,000.3**
Total Petroleum	**1,375.2**	**891.4**	**3,780.5**	**20,326.1**	**1,289.4**	**374.8**	**28,037.5**	**97.4**	**64.9**	**280.9**	**1,457.9**	**97.5**	**27.2**	**2,025.9**
Asphalt & Road Oil														
Aviation Gasoline				45.0			45.0				3.1			3.1
Distillate Fuel Oil	959.2	525.4	1,098.5	3,554.8	96.5	74.0	6,308.4	70.9	38.9	81.2	262.9	7.1	5.5	466.5
Jet Fuel				2,590.1	NA	61.0	2,651.1				184.2		4.3	188.6
Kerosene	63.9	11.8	12.3			2.6	90.6	4.7	0.9	0.9			0.2	6.6
LPG	352.1	102.3	380.2	22.9		14.4	871.9	21.8	6.3	23.5	1.4		0.9	53.9
Lubricants														
Motor Gasoline		22.1	36.7	13,813.0		101.0	13,972.8		1.6	2.6	983.7		7.2	995.1
Residual Fuel		229.8	364.1	300.3	1,162.6	121.8	2,178.7		17.3	27.3	22.6	87.3	9.2	163.6
Other Petroleum														
AvGas Blend Components			0.2				0.2			0.0				0.0
Crude Oil			50.9				50.9			3.8				3.8
MoGas Blend Components			53.7				53.7			3.8				3.8
Misc. Products														
Naphtha (<401 deg. F)														
Other Oil (>401 deg. F)														
Pentanes Plus			125.2				125.2			8.8				8.8
Petroleum Coke			591.2		30.4		621.5			60.4		3.1		63.5
Still Gas			1,436.5				1,436.5			95.8				95.8
Special Naphtha														
Unfinished Oils			(369.0)				(369.0)			(27.3)				(27.3)
Waxes														
Geothermal					**52.7**		**52.7**					**0.4**		**0.4**
Total Coal	**5,897.2**	**3,698.1**	**13,137.3**	**21,006.0**	**20,911.6**	**381.9**	**65,032.0**	**338.3**	**219.0**	**845.1**	**1,494.0**	**1,820.8**	**27.9**	**4,745.1**

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-34), and international bunker fuel consumption (see Table A-35).

[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.

NE (Not Estimated)

NA (Not Available)

Table A-34: Unadjusted Non-Energy Fuel Consumption (TBtu)

Sector/Fuel Type	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Industry	**4,544.0**	**5,089.7**	**5,151.0**	**5,376.1**	**5,632.6**	**5,843.7**	**5,576.8**	**5,263.7**	**5,425.7**	**5,342.9**	**5,847.8**	**5,483.3**	**5,470.0**	**5,225.2**	**4,770.3**	**4,510.2**	**4,764.6**	**4,729.4**	**4,629.1**
Industrial Coking Coal	+	37.8	24.1	0.0	10.9	40.1	53.6	24.8	40.3	51.9	167.8	80.5	62.9	2.3	29.2	6.4	64.8	60.8	122.4
Industrial Other Coal	8.2	11.3	11.4	11.2	10.4	11.1	12.4	11.3	12.0	11.9	11.9	11.9	11.9	11.9	11.9	11.9	10.3	10.3	10.3
Natural Gas to Chemical Plants, Other Uses	305.9	371.0	388.7	406.4	426.6	413.5	401.7	391.8	380.7	345.3	306.6	270.4	233.4	233.6	233.6	233.6	311.8	311.8	311.8
Asphalt & Road Oil	1,170.2	1,178.2	1,175.9	1,223.6	1,262.6	1,324.4	1,275.7	1,256.9	1,240.0	1,219.5	1,303.8	1,323.2	1,261.2	1,197.0	1,012.0	873.1	877.8	859.5	826.7
LPG	1,201.4	1,586.9	1,652.0	1,670.4	1,744.4	1,820.7	1,759.3	1,642.3	1,766.3	1,701.6	1,768.5	1,659.5	1,734.6	1,726.7	1,596.6	1,748.0	1,901.6	1,996.1	2,003.9
Lubricants	186.3	177.8	172.5	182.3	190.8	192.8	189.9	174.0	171.9	159.0	161.0	160.2	156.1	161.2	149.6	134.5	149.5	141.8	130.5
Pentanes Plus	125.2	169.0	177.5	164.5	147.0	182.5	171.6	131.6	111.9	110.4	111.2	98.1	70.1	89.7	76.5	63.8	77.7	27.3	45.9
Naphtha (<401 deg. F)	347.8	373.0	479.3	536.4	584.0	502.1	613.5	493.7	582.6	613.0	749.4	698.7	628.9	562.5	477.2	471.9	490.6	487.3	453.9
Other Oil (>401 deg. F)	753.9	801.0	729.7	861.2	818.7	811.1	722.2	662.5	632.1	699.4	779.5	708.0	790.6	744.1	647.8	424.8	452.5	388.5	287.2
Still Gas	36.7	47.9	2.2	12.1	6.2	23.0	17.0	49.3	61.7	59.0	62.9	67.7	57.2	44.2	47.3	133.9	147.8	163.6	161.1
Petroleum Coke	123.1	120.6	118.6	87.5	150.8	216.0	98.7	174.3	145.8	122.8	218.3	186.9	213.6	201.2	225.1	180.7	61.0	62.4	66.3
Special Naphtha	107.1	70.8	74.5	72.3	107.3	145.4	97.4	78.5	102.4	80.5	51.0	62.5	70.1	78.0	84.9	46.2	26.1	22.6	14.7
Other (Wax/Misc.)																			
Distillate Fuel Oil	7.0	6.8	6.8	6.8	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	17.5	17.5	17.5	17.5	17.5	17.5	17.5
Waxes	33.3	40.6	48.7	43.7	42.4	37.4	33.1	36.3	32.2	31.1	30.8	31.4	26.2	21.9	19.1	12.2	17.1	15.1	15.3
Miscellaneous Products	137.8	97.1	89.0	97.8	119.0	111.9	119.2	124.9	134.2	126.0	113.4	112.8	136.0	133.5	142.0	151.8	158.7	164.7	161.6
Transportation	**176.0**	**167.9**	**163.0**	**172.1**	**180.2**	**182.1**	**179.4**	**164.3**	**162.4**	**150.1**	**152.1**	**151.3**	**147.4**	**152.2**	**141.3**	**127.1**	**141.2**	**133.9**	**123.2**
Lubricants	176.0	167.9	163.0	172.1	180.2	182.1	179.4	164.3	162.4	150.1	152.1	151.3	147.4	152.2	141.3	127.1	141.2	133.9	123.2
U.S. Territories	**86.7**	**90.8**	**121.7**	**131.6**	**135.0**	**139.3**	**152.2**	**80.3**	**140.2**	**123.5**	**110.8**	**121.9**	**133.4**	**108.4**	**132.1**	**59.6**	**123.6**	**123.6**	**123.6**
Lubricants	0.7	2.0	1.5	2.5	1.3	1.4	3.1	0.0	3.0	4.9	5.1	4.6	6.2	5.9	2.7	1.0	1.0	1.0	1.0
Other Petroleum (Misc. Prod.)	86.0	88.8	120.2	129.1	133.8	138.0	149.1	80.3	137.2	118.6	105.7	117.3	127.2	102.5	129.4	58.5	122.6	122.6	122.6
Total	**4,806.7**	**5,348.5**	**5,435.7**	**5,679.8**	**5,947.9**	**6,165.1**	**5,908.3**	**5,508.4**	**5,728.3**	**5,616.5**	**6,110.7**	**5,756.6**	**5,750.8**	**5,485.9**	**5,043.7**	**4,696.8**	**5,029.4**	**4,987.0**	**4,876.0**

Note: These values are unadjusted non-energy fuel use provided by EIA. They have not yet been adjusted to remove petroleum feedstock exports and processes accounted for in the Industrial Processes Chapter.
+ Does not exceed 0.05 TBtu.

Table A-35: International Bunker Fuel Consumption (TBtu)

Fuel Type	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Marine Residual Fuel Oil	715.7	523.2	536.4	575.2	594.8	489.7	444.1	426.0	448.9	471.8	553.1	581.0	599.4	607.5	654.6	604.8	619.8	518.4	459.5
Marine Distillate Fuel Oil & Other	158.0	125.7	114.1	125.5	158.8	113.6	85.9	72.4	82.6	103.9	143.6	126.9	119.3	111.3	122.2	111.0	128.2	107.4	91.7
Aviation Jet Fuel	539.4	703.4	718.3	754.4	748.8	796.9	880.1	799.7	774.8	783.0	797.7	853.1	855.6	872.7	796.8	749.1	865.4	919.9	916.3
Total	**1,413.1**	**1,352.3**	**1,368.8**	**1,455.1**	**1,502.4**	**1,400.3**	**1,410.0**	**1,298.1**	**1,306.3**	**1,358.7**	**1,494.4**	**1,561.0**	**1,574.2**	**1,591.5**	**1,573.6**	**1,464.9**	**1,613.4**	**1,545.7**	**1,467.4**

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

Table A- 36: Key Assumptions for Estimating CO_2 Emissions

Fuel Type	C Content Coefficient (Tg C/QBtu)
Coal	
Residential Coal	[a]
Commercial Coal	[a]
Industrial Coking Coal	[a]
Industrial Other Coal	[a]
Electric Power Coal	[a]
U.S. Territory Coal (bit)	25.14
Pipeline Natural Gas	**[a]**
Flare Gas [a]	14.92
Petroleum	
Asphalt & Road Oil	20.55
Aviation Gasoline	18.86
Distillate Fuel Oil No. 1	19.98
Distillate Fuel Oil No. 2[b]	20.17
Distillate Fuel Oil No. 4	20.47
Jet Fuel	[a]
Kerosene	19.96
LPG (energy use)	[a]
LPG (non-energy use)	[a]
Lubricants	20.20
Motor Gasoline	[a]
Residual Fuel Oil No. 5	19.89
Residual Fuel Oil No. 6 [b]	20.48
Other Petroleum	
AvGas Blend Components	18.87
Crude Oil	[a]
MoGas Blend Components	[a]
Misc. Products	[a]
Misc. Products (Territories)	20.00
Naphtha (<401 deg. F)	18.55
Other Oil (>401 deg. F)	20.17
Pentanes Plus	19.10
Petroleum Coke	27.85
Still Gas	18.20
Special Naphtha	19.74
Unfinished Oils	[a]
Waxes	19.80
Geothermal	**2.05**

[a] Flare gas is not used in the CO_2 from fossil fuel combustion calculations and is presented for informational purposes only.

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

Sources: C coefficients from EIA (2009b) and EPA 2010a.

[a] These coefficients vary annually due to fluctuations in fuel quality (see Table A- 37)

Table A- 37: Annually Variable C Content Coefficients by Year (Tg C/QBtu)

Fuel Type	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Residential Coal	26.20	26.13	26.04	25.90	26.07	25.98	26.01	26.00	25.98	26.04	25.91	26.09	26.29	25.94	25.71*	25.71*	25.71*	25.71*	25.71*
Commercial Coal	26.00	26.13	26.04	25.90	26.07	25.98	26.01	26.00	25.98	26.04	25.91	26.09	26.29	25.94	25.71	25.71	25.71	25.71	25.71
Industrial Coking Coal	31.00	31.00	31.00	31.00	31.00	31.00	31.00	31.00	31.00	31.00	31.00	31.00	31.00	31.00	31.00	31.00	31.00	31.00	31.00
Industrial Other Coal	25.82	25.80	25.75	25.75	25.79	25.80	25.74	25.66	25.57	25.55	25.56	25.80	25.84	25.82	25.82	25.82	25.82	25.82	25.82
Electric Power Coal	25.96	25.93	25.93	25.93	25.95	25.98	26.00	26.00	26.05	26.09	26.10	26.09	26.04	26.05	26.05	26.05	26.05	26.05	26.05
Pipeline Natural Gas	14.45	14.46	14.46	14.46	14.44	14.46	14.47	14.46	14.46	14.44	14.46	14.46	14.46	14.46	14.46	14.46	14.46	14.46	14.46
LPG (energy use)	16.86	16.82	16.82	16.84	16.81	16.86	16.89	16.87	16.85	16.86	16.84	16.84	16.83	16.82	16.83	16.83	16.83	16.83	16.83
LPG (non-energy use)	17.06	17.09	17.10	17.08	17.08	17.07	17.09	17.10	17.09	17.09	17.07	17.06	17.06	17.05	17.06	17.06	17.06	17.06	17.06
Motor Gasoline	19.42	19.36	19.35	19.36	19.37	19.32	19.33	19.34	19.38	19.36	19.38	19.36	19.45	19.56	19.46	19.46	19.46	19.46	19.46
Jet Fuel	19.40	19.34	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70
MoGas Blend Components	19.42	19.36	19.35	19.36	19.37	19.32	19.33	19.34	19.38	19.36	19.38	19.36	19.45	19.56	19.46	19.46	19.46	19.46	19.46
Misc. Products	20.15	20.21	20.23	20.22	20.22	20.17	20.22	20.27	20.28	20.25	20.31	20.31	20.28	20.28	20.31	20.31	20.31	20.31	20.31
Unfinished Oils	20.15	20.21	20.23	20.22	20.22	20.17	20.22	20.27	20.28	20.25	20.31	20.31	20.28	20.28	20.31	20.31	20.31	20.31	20.31
Crude Oil	20.15	20.21	20.23	20.22	20.22	20.17	20.22	20.27	20.28	20.25	20.31	20.31	20.28	20.28	20.31	20.31	20.31	20.31	20.31

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

Source: EPA (2010a)

Table A-38: Electricity Consumption by End-Use Sector (Billion Kilowatt-Hours)

End-Use Sector	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Residential	924	1,043	1,083	1,076	1,130	1,145	1,192	1,202	1,265	1,276	1,292	1,359	1,352	1,392	1,380	1,364	1,446	1,423	1,375
Commercial	838	953	980	1,027	1,078	1,104	1,159	1,191	1,205	1,199	1,230	1,275	1,300	1,336	1,336	1,307	1,330	1,328	1,327
Industrial	1,070	1,163	1,186	1,194	1,212	1,230	1,235	1,159	1,156	1,181	1,186	1,169	1,158	1,154	1,141	1,044	1,103	1,124	1,123
Transportation	5	5	5	5	5	5	5	6	6	7	7	8	7	8	8	8	8	8	7
Total	**2,837**	**3,164**	**3,254**	**3,302**	**3,425**	**3,484**	**3,592**	**3,557**	**3,632**	**3,662**	**3,716**	**3,811**	**3,817**	**3,890**	**3,865**	**3,724**	**3,886**	**3,883**	**3,832**

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

Source: EIA (2014)

2.2. Methodology for Estimating the Carbon Content of Fossil Fuels

This sub-annex presents the background and methodology for estimating the carbon (C) content of fossil fuels combusted in the United States. The C content of a particular fossil fuel represents the maximum potential emissions to the atmosphere if all C in the fuel is oxidized during combustion. The C content coefficients used in past editions of this report were developed using methods first outlined in the U.S. Energy Information Administration's (EIA) *Emissions of Greenhouse Gases in the United States: 1987-1992* (1994) and were developed primarily by EIA. For this report, EPA has updated many of the C content coefficients based on carbon dioxide emission factors developed for the Mandatory Reporting of Greenhouse Gases Rule, signed in September 2009 (EPA, 2009b, 2010). This sub-annex describes an updated methodology for estimating the C content of natural gas, and presents a time-series analysis of changes in U.S. C content coefficients for coal, petroleum products and natural gas. A summary of C content coefficients used in this report appears in Table A- 39.

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

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

Table A- 39: Carbon Content Coefficients Used in this Report (Tg Carbon/QBtu)

Fuel Type	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Coal																			
Residential Coal[a]	26.20	26.13	26.04	25.90	26.07	25.98	26.01	26.00	25.98	26.04	25.91	26.09	26.29	25.94	25.71*	25.71*	25.71*	25.71*	25.71*
Commercial Coal[a]	26.20	26.13	26.04	25.90	26.07	25.98	26.01	26.00	25.98	26.04	25.91	26.09	26.29	25.94	25.71	25.71	25.71	25.71	25.71
Industrial Coking Coal[a]	25.53	25.57	25.56	25.59	25.62	25.59	25.63	25.63	25.65	25.63	25.63	25.60	25.60	25.61	25.61	25.61	25.61	25.61	25.61
Industrial Other Coal[a]	25.82	25.80	25.75	25.75	25.79	25.80	25.74	25.66	25.57	25.55	25.56	25.80	25.84	25.82	25.82	25.82	25.82	25.82	25.82
Utility Coal[a,b]	25.96	25.93	25.93	25.93	25.95	25.98	26.00	26.00	26.05	26.09	26.10	26.09	26.04	26.05	26.05	26.05	26.05	26.05	26.05
Pipeline Natural Gas[c]	**14.45**	**14.46**	**14.46**	**14.46**	**14.44**	**14.46**	**14.47**	**14.46**	**14.46**	**14.44**	**14.46**	**14.46**	**14.46**	**14.46**	**14.46**	**14.46**	**14.46**	**14.46**	**14.46**
Flare Gas	**15.31**	**15.31**	**15.31**	**15.31**	**15.31**	**15.31**	**15.31**	**15.31**	**15.31**	**15.31**	**15.31**	**15.31**	**15.31**	**15.31**	**15.31**	**15.31**	**15.31**	**15.31**	**15.31**
Petroleum																			
Asphalt and Road Oil	20.55	20.55	20.55	20.55	20.55	20.55	20.55	20.55	20.55	20.55	20.55	20.55	20.55	20.55	20.55	20.55	20.55	20.55	20.55
Aviation Gasoline	18.86	18.86	18.86	18.86	18.86	18.86	18.86	18.86	18.86	18.86	18.86	18.86	18.86	18.86	18.86	18.86	18.86	18.86	18.86
Distillate Fuel Oil No. 1	19.98	19.98	19.98	19.98	19.98	19.98	19.98	19.98	19.98	19.98	19.98	19.98	19.98	19.98	19.98	19.98	19.98	19.98	19.98
Distillate Fuel Oil No. 2	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17
Distillate Fuel Oil No. 4	20.47	20.47	20.47	20.47	20.47	20.47	20.47	20.47	20.47	20.47	20.47	20.47	20.47	20.47	20.47	20.47	20.47	20.47	20.47
Jet Fuel[a]	19.40	19.34	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70
Kerosene	19.96	19.96	19.96	19.96	19.96	19.96	19.96	19.96	19.96	19.96	19.96	19.96	19.96	19.96	19.96	19.96	19.96	19.96	19.96
LPG (energy use)[c]	16.86	16.82	16.82	16.84	16.81	16.86	16.89	16.87	16.85	16.86	16.84	16.84	16.83	16.82	16.83	16.83	16.83	16.83	16.83
LPG (non-energy use)[c]	17.06	17.09	17.10	17.08	17.08	17.07	17.09	17.10	17.09	17.09	17.07	17.06	17.06	17.05	17.06	17.06	17.06	17.06	17.06
Lubricants	20.20	20.20	20.20	20.20	20.20	20.20	20.20	20.20	20.20	20.20	20.20	20.20	20.20	20.20	20.20	20.20	20.20	20.20	20.20
Motor Gasoline[c]	19.42	19.36	19.35	19.36	19.37	19.32	19.33	19.34	19.38	19.36	19.38	19.36	19.45	19.56	19.46	19.46	19.46	19.46	19.46
Residual Fuel No. 5	19.89	19.89	19.89	19.89	19.89	19.89	19.89	19.89	19.89	19.89	19.89	19.89	19.89	19.89	19.89	19.89	19.89	19.89	19.89
Residual Fuel No. 6	20.48	20.48	20.48	20.48	20.48	20.48	20.48	20.48	20.48	20.48	20.48	20.48	20.48	20.48	20.48	20.48	20.48	20.48	20.48
Other Petroleum																			
Av. Gas Blend Comp.	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87
Mo. Gas Blend Comp[c]	19.42	19.36	19.35	19.36	19.37	19.32	19.33	19.34	19.38	19.36	19.38	19.36	19.45	19.56	19.46	19.46	19.46	19.46	19.46
Crude Oil[c]	20.15	20.21	20.23	20.22	20.22	20.17	20.22	20.27	20.28	20.25	20.31	20.31	20.28	20.28	20.31	20.31	20.31	20.31	20.31
Misc. Products[c]	20.15	20.21	20.23	20.22	20.22	20.17	20.22	20.27	20.28	20.25	20.31	20.31	20.28	20.28	20.31	20.31	20.31	20.31	20.31
Misc. Products (Terr.)	20.15	20.21	20.23	20.22	20.22	20.17	20.22	20.27	20.28	20.25	20.31	20.31	20.28	20.28	20.31	20.31	20.31	20.31	20.31
Naphtha (<401 deg. F)	18.55	18.55	18.55	18.55	18.55	18.55	18.55	18.55	18.55	18.55	18.55	18.55	18.55	18.55	18.55	18.55	18.55	18.55	18.55
Other oil (>401 deg. F)	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17
Pentanes Plus	19.10	19.10	19.10	19.10	19.10	19.10	19.10	19.10	19.10	19.10	19.10	19.10	19.10	19.10	19.10	19.10	19.10	19.10	19.10
Petroleum Coke	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85
Still Gas	18.20	18.20	18.20	18.20	18.20	18.20	18.20	18.20	18.20	18.20	18.20	18.20	18.20	18.20	18.20	18.20	18.20	18.20	18.20
Special Naphtha	19.74	19.74	19.74	19.74	19.74	19.74	19.74	19.74	19.74	19.74	19.74	19.74	19.74	19.74	19.74	19.74	19.74	19.74	19.74
Unfinished Oils[c]	20.15	20.21	20.23	20.22	20.22	20.17	20.22	20.27	20.28	20.25	20.31	20.31	20.28	20.28	20.31	20.31	20.31	20.31	20.31
Waxes	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80
Other Wax and Misc.	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80
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**	**2.05**	**2.05**	**2.05**	**2.05**	**2.05**	**2.05**	**2.05**

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

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

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

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

Coal

Approximately one-third of all U.S. CO_2 emissions from fossil fuel combustion are associated with coal consumption. Although the IPCC guidelines provide C contents for coal according to rank, it was necessary to develop C content coefficients by consuming sector to match the format in which coal consumption is reported by EIA. Because the C content of coal varies by the state in which it was mined and by coal rank, and because the sources of coal for each consuming sector vary by year, the weighted average C content for coal combusted in each consuming sector also varies over time. A time series of C contents by coal rank and consuming sector appears in Table A- 40.[8]

Methodology

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

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

C contents by rank and state of origin are estimated on the basis of 7,092 coal samples, 6,588 of which were collected by the U.S. Geological Survey (USGS 1998) and 504 samples that come from the Pennsylvania State University database (PSU 2010). These coal samples are classified according to rank and state of origin. For each rank in each state, the average heat content and C content of the coal samples are calculated based on the proximate (heat) and ultimate (percent carbon) analyses of the samples. Dividing the C content (reported in pounds CO_2) by the heat content (reported in million Btu or MMBtu) yields an average C content coefficient. This coefficient is then converted into units of Tg C/QBtu.

Step 2. Determine weighted average carbon content by state

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

Step 3. Allocate sectoral consumption by state of origin

U.S. energy statistics[9] through 2007 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.[10] Because U.S. energy statistics do not provide the distribution of coal rank consumed by each consuming sector, it is assumed that each sector consumes a representative mixture of coal ranks from a particular state that matches the mixture of all coal produced in that state during the year. Thus, the weighted state-level factor developed in Step 2 is applied.

Step 4. Weight sectoral carbon contents to reflect the rank and state of origin of coal consumed

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

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

where,

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[8] 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.

[9] U.S. Energy Information Administration (EIA). *Coal Distribution – Annual* (2001-2008); and *Coal Industry Annual* (1990-2000).

[10] Beginning in 2008, the EIA collects and reports data on commercial and institutional coal consumption, rather than residential and commercial consumption. Thus, the residential / commercial coal coefficient reported in Table A- 39 for 2009 represents the mix of coal consumed by commercial and institutional users. Currently, only an extremely small amount of coal is consumed in the U.S. Residential Sector.

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

Table A- 40: Carbon Content Coefficients for Coal by Consuming Sector and Coal Rank (Tg C/QBtu) (1990-2012)

Consuming Sector	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Electric Power	25.96	25.93	25.93	25.93	25.95	25.98	26.00	26.00	26.05	26.09	26.10	26.09	26.04	26.05	26.05	26.05	26.05	26.05	26.05
Industrial Coking	25.53	25.57	25.56	25.59	25.62	25.59	25.63	25.63	25.65	25.63	25.63	25.60	25.60	25.61	25.61	25.61	25.61	25.61	25.61
Other Industrial	25.82	25.80	25.75	25.75	25.79	25.80	25.74	25.66	25.57	25.55	25.56	25.80	25.84	25.82	25.82	25.82	25.82	25.82	25.82
Residential/ Commercial	26.20	26.13	26.04	25.90	26.07	25.98	26.01	26.00	25.98	26.04	25.91	26.09	26.29	25.94	25.71	25.71	25.71	25.71	25.71
Coal Rank																			
Anthracite	28.28	28.28	28.28	28.28	28.28	28.28	28.28	28.28	28.28	28.28	28.28	28.28	28.28	28.28	28.28	28.28	28.28	28.28	28.28
Bituminous	25.38	25.42	25.43	25.43	25.43	25.44	25.45	25.46	25.46	25.45	25.45	25.45	25.45	25.45	25.44	25.44	25.44	25.44	25.44
Sub-bituminous	26.50	26.50	26.50	26.50	26.50	26.50	26.49	26.50	26.50	26.50	26.50	26.50	26.50	26.50	26.50	26.50	26.50	26.50	26.50
Lignite	26.58	26.59	26.58	26.59	26.59	26.60	26.61	26.62	26.63	26.62	26.62	26.62	26.62	26.64	26.65	26.65	26.65	26.65	26.65

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

Sources: C content coefficients calculated from USGS (1998) and PSU (2010); data presented in EPA (2010b).

Step 5. Develop national-level carbon contents by rank for comparison to IPCC defaults

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

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

where,

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

Data Sources

The ultimate analysis of coal samples was based on the 7,092 coal samples, 6,588 of which are from USGS (1998) and 504 that come from the Pennsylvania State University Coal Database (PSU 2010). Data contained in the USGS's CoalQual Database are derived primarily from samples taken between 1973 and 1989, and were largely reported in State Geological Surveys. Data in the PSU Coal Database are mainly from samples collected by PSU since 1967 and are housed at the PSU Sample Bank. Only the subset of PSU samples that are whole-seam channel samples are included in the development of carbon factors in order to increase data accuracy.

Data on coal consumption by sector and state of origin, as well as coal production by state and rank, were obtained from EIA. The EIA's *Annual Coal Report* is the source for state coal production by rank from 2001-2008. In prior years, the EIA reported this data in its *Coal Industry Annual*. Data for coal consumption by state of origin and consuming sector for 2001 to 2008 was obtained from the EIA's *Coal Distribution – Annual*. For 1990-2000, end-use data was obtained from the *Coal Industry Annual*.

Uncertainty

C contents vary considerably by state. Bituminous coal production and sub-bituminous coal production represented 47.3 percent and 46.1 percent of total U.S. supply in 2008, respectively. State average C content coefficients for bituminous coal vary from a low of 85.59 kg CO_2 per MMBtu in Texas to a high of 105.21 kg CO_2 per MMBtu in Montana. However, Texas bituminous coal is considered anomalous,[11] has not been produced since 2004 and production since 1990 peaked at just 446,000 short tons in 1996. The next lowest average emission factor for bituminous coal is found in Western Kentucky (91.36 kg CO_2 per MMBtu). In 2000, Montana produced no bituminous coal and Western Kentucky production accounted for just 4.5 percent of overall bituminous production. In 2008, more than 60 percent of bituminous coal was produced in three states: West Virginia, Kentucky (predominantly from the Eastern production region), and Pennsylvania, and this share has remained fairly constant since 1990. These three states show a variation in C content for bituminous coals of ±0.7 percent, based on more than 2,000 samples (see Table A-41).

Similarly, the C content coefficients for sub-bituminous coal range from 91.29 kg CO_2 per MMBtu in Utah to 98.10 kg CO_2 per MMBtu in Alaska. However, Utah has no recorded production of sub-bituminous coal since 1990. Production of sub-bituminous coal in Alaska has made up less than 0.7 percent of total sub-bituminous production since 1990, with even this small share declining over time. Wyoming has represented between 75 percent and 87 percent of total sub-bituminous coal production in the United States in each year since 1990. Thus, the C content coefficient for Wyoming (97.22 kg CO_2 per MMBtu), based on 455 samples, dominates the national average.

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

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[11] See, for example: San Filipo, 1999. USGS. (U.S. Geological Survey Open-File Report 99-301), Ch. 4.

For comparison, J. Quick (2010) completed an analysis similar in methodology to that used here, in order to generate national average carbon emission factors as well as county-level factors. This study's rank-based national average factors have a maximum deviation from the factors developed in this Inventory report of -0.55 percent, which is for lignite (range: -0.55 to +0.1 percent). This corroboration further supports the assertion of minimal uncertainty in the application of the rank-based factors derived for the purposes of this Inventory.

Table A-41: Variability in Carbon Content Coefficients by Rank Across States (Kilograms CO_2 Per MMBtu)

State	Number of Samples	Bituminous	Sub-bituminous	Anthracite	Lignite
Alabama	951	92.84	-	-	99.10
Alaska	91	98.33	98.10	-	98.65
Arizona	15	93.94	97.34	-	-
Arkansas	80	96.36	-	-	94.97
Colorado	318	94.37	96.52	-	101.10
Georgia	35	95.01	-	-	-
Idaho	1	-	94.90	-	-
Illinois	57	92.33	-	-	-
Indiana	146	92.65	-	-	-
Iowa	100	91.87	-	-	-
Kansas	29	90.91	-	-	-
Kentucky	897	92.61	-	-	-
Louisiana	1	-	-	-	96.01
Maryland	47	94.29	-	-	-
Massachusetts	3	-	-	114.82	-
Michigan	3	92.88	-	-	-
Mississippi	8	-	-	-	98.19
Missouri	111	91.71	-	-	-
Montana	309	105.21	97.73	103.60	99.40
Nevada	2	94.41	-	-	99.86
New Mexico	185	94.29	94.89	103.92	-
North Dakota	202	-	93.97	-	99.48
Ohio	674	91.84	-	-	-
Oklahoma	63	92.33	-	-	-
Pennsylvania	861	93.33	-	103.68	-
Tennessee	61	92.82	-	-	-
Texas	64	85.59	94.19	-	94.47
Utah	169	95.75	91.29	-	-
Virginia	470	93.51	-	98.54	-
Washington	18	94.53	97.36	102.53	106.55
West Virginia	612	93.84	-	-	-
Wyoming	503	94.80	97.22	-	-
U.S. Average	**7,092**	**93.13**	**96.94**	**104.29**	**98.63**

Notes: - Indicates No Sample Data Available.

Sources: Calculated from USGS (1998), and PSU (2010); data presented in EPA (2010).

Natural Gas

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

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

Methodology

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

Step 1. Define pipeline-quality natural gas

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

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

Step 2. Define flared gas

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

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

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

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

A relationship between C content and heat content may be used to develop a C content coefficient for natural gas consumed in the United States. In 1994, EIA examined the composition (including C contents) of 6,743 samples of pipeline-quality natural gas from utilities and/or pipeline companies in 26 cities located in 19 states. To demonstrate that these samples were representative of actual natural gas "as consumed" in the United States, their heat content was compared to that of the national average. For the most recent year, the average heat content of natural gas consumed in the United States was 1,029 Btu per cubic foot, and has varied by less than 1 percent (1,027 to 1,029 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

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[12] 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.

range of natural gas consumed in the United States, suggesting that these samples continue to be representative of natural gas “as consumed” in the United States. The average and median composition of these samples appear in Table A-42.

Table A-42: Composition of Natural Gas (Percent)

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

Source: Gas Technology Institute (1992).

Carbon contents were calculated for a series of sub-samples based on their CO_2 content and heat content. Carbon contents were calculated for the groups of samples with less than 1.0 percent (n=5,181) and less than 1.5 percent CO_2 only (n=6,522) and those with less than 1.0 or 1.5 percent CO_2 and less than 1,050 Btu/cf (n=4,888 and 6,166, respectively). These stratifications were chosen to exclude samples with CO_2 content and heat contents outside the range of pipeline-quality natural gas. In addition, hexane was removed from the samples since it is usually stripped out of raw natural gas before delivery because it is a valuable natural gas liquid used as a feedstock for gasoline. The average carbon contents for the four separate sub-samples are shown below in Table A-43.

Table A-43: Carbon Content of Pipeline-Quality Natural Gas by CO_2 and Heat Content (Tg C/QBtu)

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

Source: EPA (2010).

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

A regression analysis was performed on the sub-samples in to further examine the relationship between carbon content and heat content. The regression used carbon content as the dependent variable and heat content as the independent variable. The resulting R-squared values[13] for each of the sub-samples ranged from 0.79 for samples with less than 1.5 percent CO_2 and under 1,050 Btu/cf to 0.91 for samples containing less than 1.0 percent CO_2 only. However, the sub-sample with less than 1.5 percent CO_2 and 1,050 Btu/cf was chosen as the representative sample for two reasons. First, it most accurately reflects the range of CO_2 content and heat content of pipeline quality natural gas. Secondly, the R-squared value, although it is the lowest of the sub-groups tested, remains relatively high. This high R-squared indicates a low percentage of variation in C content as related to heat content. The regression for this sub-sample resulted in the following equation:

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

This equation was used to estimate the annual predicted carbon content of natural gas from 1990 to 2010 based on the EIA’s national average pipeline-quality gas heat content for each year. The table of average C contents for each year is shown below in Table A-44.

Table A-44: Carbon Content Coefficients for Natural Gas (Tg Carbon/QBtu)

Fuel Type	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Natural Gas	14.45	14.46	14.46	14.46	14.44	14.46	14.47	14.46	14.46	14.44	14.46	14.46	14.46	14.46	14.46	14.46	14.46	14.46	14.46

Source: EPA (2010)

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

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

Selecting a C content coefficient for flare gas was much more difficult than for pipeline natural gas, because of the uncertainty of its composition and 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 C content for samples with more than 1,100 Btu per cubic foot (n=18) was chosen as the relevant sub-sample from which to calculate a flare gas carbon content. The sample dataset did not include any samples with more than 1,130 Btu per cubic foot.

Hexane was not removed from flare gas samples since it is assumed that natural gas liquids are present in samples with higher heat contents. Carbon contents were calculated for each sample with a heat content of more than 1,100 Btu per cubic foot. The simple average C content for the sample sub-set representing flare gas is shown below in Table A-45.

Table A-45: Carbon Content of Flare Gas (Tg C/QBtu)

Relevant Sub-Sample	Average Carbon Content
>1,100 Btu/cf	15.31

Source: EPA (2010)

Data Sources

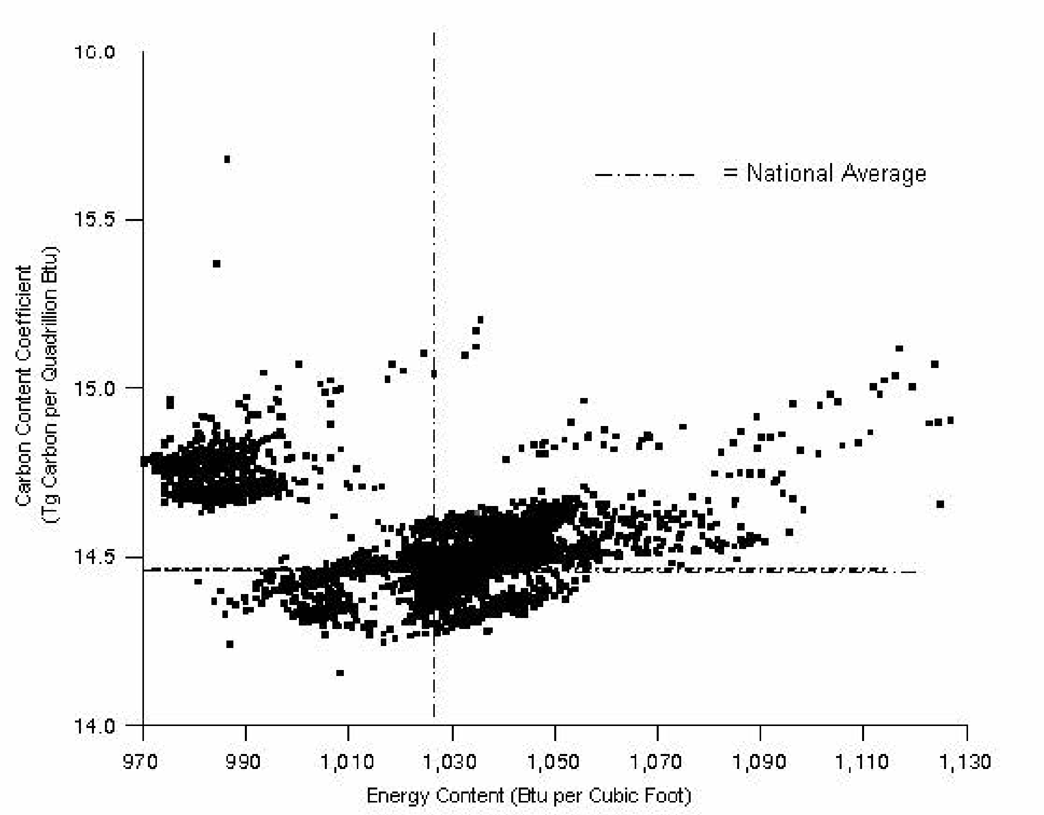
Natural gas samples were obtained from the Gas Technology Institute (1992). Average heat content data for natural gas consumed in the United States was taken from EIA (2009a).

Uncertainty

The assignment of C 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 A-1 shows the relationship between the calculated C content 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 C 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 C emission coefficient to be predicted with an accuracy of ±5.0 percent.

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



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

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

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

For the full sample (n=6,743), the average C content of a cubic foot of gas was 14.48 Tg C/QBtu (see Table A-44). Additionally, a regression analysis using the full sample produced a predicted C content of 14.49 Tg C/QBtu based on a heat content of 1,029 Btu/cf (the average heat content in the U.S. for the most recent year). However, these two values include an upward influence on the resulting carbon content that is caused by inclusion in the sample set of the samples that contain large amounts of inert carbon dioxide and those samples with more than 1,050 Btu per cubic foot that contain an unusually large amount of NGLs. Because typical gas consumed in the United States does not contain such a large amount of carbon dioxide or natural gas liquids, a carbon content of 14.47 Tg C/QBtu, based on samples with less than 1.5 percent carbon dioxide and less than 1,050 Btu per cubic foot, better represents the pipeline-quality fuels typically consumed.

Petroleum

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

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

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

where,

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

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

Petroleum products vary between 5.6 degrees API gravity (dense products such as asphalt and road oil) and 247 degrees (ethane).[14] This is a range in density of 60 to 150 kilograms per barrel, or ±50 percent. The variation in C content, however, is much smaller (±5 to 7 percent) for products produced by standard distillation refining: ethane is 80 percent C by weight, while petroleum coke is 90 to 92 percent C. This tightly bound range of C contents can be explained by basic petroleum chemistry (see below). Additional refining can increase carbon contents. Calcined coke, for example, is formed by heat treating petroleum coke to about 1600 degrees Kelvin (calcining), to expel volatile materials and increase the percentage of elemental C. This product can contain as much as 97 to 99 percent carbon. Calcined coke is mainly used in the aluminum and steel industry to produce C anodes.

Petroleum Chemistry

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

Products that boil off at higher temperatures are usually more dense, which implies greater C content as well. Petroleum products with higher C contents, in general, have lower energy content per unit mass and higher energy content per unit volume than products with lower C contents. Empirical research led to the establishment of a set of quantitative relationships between density, energy content per unit weight and volume, and C and hydrogen content. Figure A-2 compares C content coefficients calculated on the basis of the derived formula with actual C content coefficients for a range of crude oils, fuel oils, petroleum products, and pure hydrocarbons. The actual fuel samples were drawn from the sources described below in the discussions of individual petroleum products.

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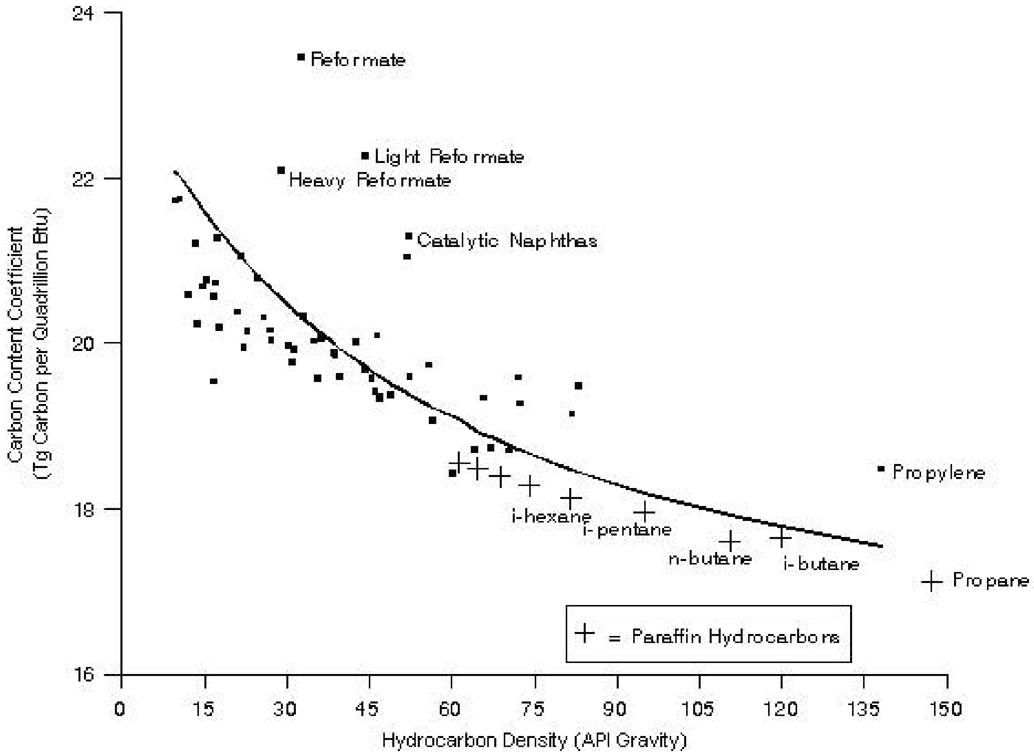
[14] API gravity is an arbitrary scale expressing the gravity or density of liquid petroleum products, as established by the American Petroleum Institute (API). The measuring scale is calibrated in terms of degrees API. The higher the API gravity, the lighter the compound. Light crude oils generally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

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



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

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

Non-hydrocarbon Impurities

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

Variations in Hydrocarbon Classes

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

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

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

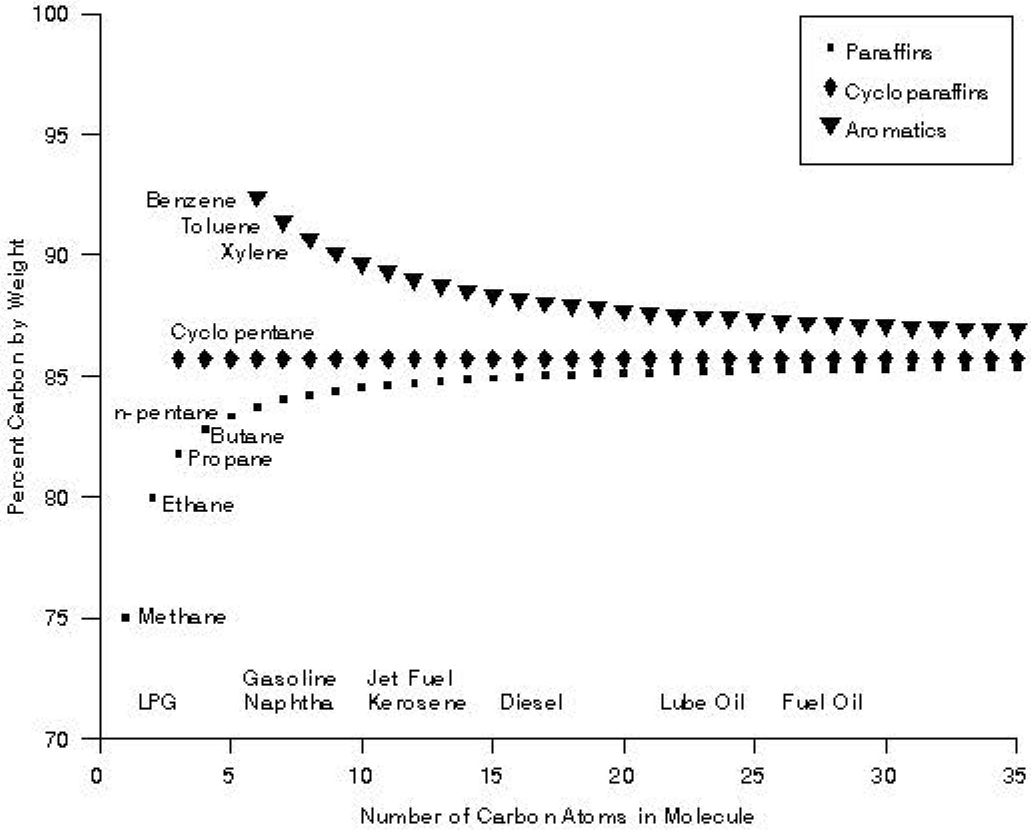
Olefins. Olefins are a very reactive and unstable form of paraffin: a straight chain with two carbon atoms double bonded together (thus are unsaturated) compared to the carbon atoms in a paraffin (which are saturated with hydrogen). They are never found in crude oil but are created in moderate quantities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

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

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

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

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



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

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

Energy Content of Petroleum Products

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

Individual Petroleum Products

The United States maintains data on the consumption of more than 20 separate petroleum products and product categories. The C contents, heat contents, and density for each product are provided below in Table A-46. A description of the methods and data sources for estimating the key parameters for each individual petroleum product appears below.

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

Fuel	2008 Carbon Content (Tg C/QBtu)	Gross Heat of Combustion (MMBtu/Barrel)	Density (API Gravity)	Percent Carbon
Motor Gasoline	19.46	(See a)	(See a)	(See a)
LPG(total)	16.97	(See b)	(See b)	(See b)
LPG (energy use)	16.83	(See b)	(See b)	(See b)
LPG (non-energy use)	17.06	(See b)	(See b)	(See b)
Jet Fuel	19.70	5.670	42.0	86.30
Distillate Fuel No. 1	19.98	5.822	35.3	86.40
Distillate Fuel No. 2	20.17	5.809	35.8	87.30
Distillate Fuel No. 4	20.47	6.135	23.2	86.47
Residual Fuel No. 5	19.89	5.879	33.0	85.67
Residual Fuel No. 6	20.48	6.317	15.5	84.67
Asphalt and Road Oil	20.55	6.636	5.6	83.47
Lubricants	20.20	6.065	25.7	85.80
Naphtha (< 400 deg. F)[a]	18.55	5.248	62.4	84.11
Other Oils (>400 deg. F)[a]	20.17	5.825	35.8	87.30
Aviation Gas	18.86	5.048	69.0	85.00
Kerosene	19.96	5.825	35.3	86.40
Petroleum Coke	27.85	6.024	-	92.28
Special Naphtha	19.74	5.248	52.0	84.75
Petroleum Waxes	19.80	5.537	43.3	85.30
Still Gas	18.20	6.000	-	77.70
Crude Oil	20.31	5.800	31.2	85.49
Unfinished Oils	20.31	5.825	31.2	85.49
Miscellaneous Products	20.31	5.796	31.2	85.49
Pentanes Plus	19.10	4.620	81.3	83.63

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

b = LPG is a blend of multiple paraffinic hydrocarbons: ethane, propane, isobutane, and normal butane, each with their own heat content, density and C content, see Table A-49.

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

- No sample data available

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

Motor Gasoline and Motor Gasoline Blending Components

Motor gasoline is a complex mixture of relatively volatile hydrocarbons with or without small quantities of additives, blended to form a fuel suitable for use in spark-ignition engines.[15] "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. CO_2 emissions. EIA collects consumption data (i.e., "petroleum products supplied" to end-users) for several types of finished gasoline over the 1990 through 2008 time period: regular, mid-grade and premium conventional gasoline (all years) and regular, mid-grade and premium reformulated gasoline (November 1994 to 2008). Leaded and oxygenated gasoline are not separately included in the data used for this report.[16]

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[15] 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.

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

The American Society for Testing and Materials (ASTM) standards permit a broad range of densities for gasoline, ranging from 50 to 70 degrees API gravity, or 111.52 to 112.65 kilograms per barrel (EIA 1994), which implies a range of possible C and energy contents per barrel. Table A- 47 reflects changes in the density of gasoline over time and across grades and formulations of gasoline through 2008.

Table A- 47: Motor Gasoline Density, 1990 – 2012 (Degrees API)

Fuel Grade	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Conventional - Winter Grade																			
Low Octane	62.0	59.8	60.6	61.5	61.8	61.6	61.6	61.7	61.6	61.8	62.4	62.6	62.7	63.1	63.0	63.0	63.0	63.0	63.0
High Octane	59.0	58.0	58.5	59.3	60.0	60.3	59.7	59.1	59.0	59.9	60.7	60.9	60.0	60.3	60.9	60.9	60.9	60.9	60.9
Conventional - Summer Grade																			
Low Octane	58.2	56.1	56.9	57.1	57.6	57.7	56.8	57.2	56.5	56.8	57.4	57.9	57.8	57.5	58.6	58.6	58.6	58.6	58.6
High Octane	55.5	55.1	55.3	56.4	55.7	57.4	55.8	55.5	55.7	56.0	57.0	57.0	57.4	56.9	58.0	58.0	58.0	58.0	58.0
Reformulated - Winter Grade																			
Low Octane	NA	61.9	62.3	62.1	62.7	62.7	62.7	62.6	61.9	62.1	62.7	62.8	62.3	62.1	62.4	62.4	62.4	62.4	62.4
High Octane	NA	59.9	60.8	62.1	61.4	61.0	61.1	61.0	61.8	61.9	61.8	61.8	61.7	62.1	62.5	62.5	62.5	62.5	62.5
Reformulated - Summer Grade																			
Low Octane	NA	58.5	58.0	58.8	58.4	58.4	58.4	58.8	58.2	59.1	58.1	58.4	58.7	58.5	59.1	59.1	59.1	59.1	59.1
High Octane	NA	56.7	57.8	58.4	58.5	57.8	58.3	58.2	58.0	58.7	58.9	58.1	59.0	59.3	59.8	59.8	59.8	59.8	59.8

Notes: NA – Not Applicable, fuel type was not analyzed.

Source: National Institute of Petroleum and Energy Research (1990 through 2012).

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

The trend in gasoline density was reversed beginning in 1996 with the development of fuel additives that raised oxygen content. In 1995, a requirement for reformulated gasoline in non-attainment areas implemented under the Clean Air Act Amendments further changed the composition of gasoline consumed in the United States. Through 2005, methyl tertiary butyl ether (MTBE), ethanol, ethyl tertiary butyl ether (ETBE) and tertiary amyl methyl ether (TAME) were added to reformulated and sometimes to conventional gasoline to boost its oxygen content, reduce its toxics impacts and increase its octane. The increased oxygen reduced the emissions of carbon monoxide and unburned hydrocarbons. These oxygen-rich blending components are also much lower in C than standard gasoline. The average gallon of reformulated gasoline consumed in 2005 contained over 10 percent MTBE and 0.6 percent TAME (by volume). The characteristics of reformulated fuel additives appear in Table A-48.

Table A-48: Characteristics of Major Reformulated Fuel Additives

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

Source: EPA, 2009b.

Since 2005, due to concerns about the potential environmental consequences of the use of MTBE in fuels, there has been a shift away from the addition of MTBE, TAME, ETBE and DIPE and towards the use of ethanol as a fuel oxygenate.[17] Ethanol, also called ethyl alcohol, is an anhydrous alcohol with molecular formula C_2H_5OH. Ethanol has a

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

lower carbon share than other oxygenates, approximately 52 percent compared to about 70 percent for MTBE and TAME. The density of ethanol was calculated by fitting density data at 10 degree intervals to a polynomial of order two and then using the fit to interpolate the value of the density at 15 degrees Celsius. A common fuel mixture of 10 percent denatured ethanol (denatured by 2 percent hydrocarbons) and 90 percent gasoline, known as E10, is widely used in the United States and does not require any modification to vehicle engines or fuel systems. The average gallon of reformulated alcohol blend gasoline in 2008 contained 8.6 percent ethanol (by volume). As of 2010, ten States require the use of ethanol-blended fuel.[18] Ethanol blends up to E85 (85 percent ethanol, 15 percent gasoline) are in use in the United States but can only be used in specially designed vehicles called flexible fuel vehicles (FFVs). Most ethanol fuel in the United States is produced using corn as feedstock,[19] although production pathways utilizing agricultural waste, woody biomass and other resources are in development.

Methodology

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

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

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

Annual C content coefficients for each gasoline grade, type and season are derived from four parameters for each constituent of the finished gasoline blend: the volumetric share of each constituent,[20] the density of the constituent, share of the constituent[21] that is C; and the energy content of a gallon of the relevant formulation of gasoline. The percent by mass of each constituent of each gasoline type was calculated using percent by volume data from NIPER and the density of each constituent. The ether additives listed in Table A-48 are accounted for in both reformulated fuels and conventional fuels, to the extent that they were present in the fuel. From 2006 onward, reformulated fuel mass percentages are calculated from their constituents, net of the share provided by ethanol. C content coefficients were then derived from the calculated percent by mass values by weighting the carbon share of each constituent by its contribution to the total mass of the finished motor gasoline product.

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

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

Data Sources

Data for the density of motor gasoline were derived from the National Institute for Petroleum and Energy Research (NIPER) (1990 through 2009). Data on the characteristics of reformulated gasoline, including C share, were also taken from NIPER (1990 through 2009).

Standard heat contents for motor gasoline of 5.253 MMBtu per barrel conventional gasoline and 5.150 MMBtu per barrel reformulated gasoline[22] were adopted from EIA (2009a).

Uncertainty

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

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[18] Ethanol.org. http://www.ethanol.org/index.php?id=79&parentid=26. Retrieved 2-19-2010.

[19] "Ethanol Market Penetration". Alternative Fuels and Advanced Vehicles Data Center, US DOE. http://www.afdc.energy.gov/afdc/ethanol/market.html. Retrieved 2-19-2010.

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

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

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

A variable number of samples are used each year to determine the average percent by volume share of each hydrocarbon within each grade, season and formulation of gasoline that are obtained from NIPER. The total number of samples analyzed for each seasonal NIPER report varies from approximately 730 to over 1,800 samples over the period from 1990 through 2008. The number of samples analyzed that underlie the calculation of the average make-up of each seasonal formulation and grade varies from approximately 50 to over 400, with the greatest number of samples each season being of conventional, regular or premium gasoline. Further, not all sample data submitted to NIPER contains data for each of the properties, such that the number of samples underlying each constituent average value for each season, grade and formulation may be variable within the single gasoline type (e.g., of the 1,073 samples for which some data was obtained for gasoline sold in Winter 1995 through 1996, benzene content was provided for all samples, while olefin, aromatic and saturate content was provided for just 736 of those samples).

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

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

The simple average for each hydrocarbon constituent is contained within a range of values that are as wide as -63/+74.5 percent of the mean across the Winter 2007 through 2008 and -51.3/+49.6 percent across the Summer 2008 samples of conventional, regular grade gasoline. However, these wide ranges exist for benzene, which generally accounts for only 1 percent, by volume, of each gallon. In contrast, saturates, the class of hydrocarbon that contribute the largest share, by volume, ranges only -6.5/+6.4 percent for the same set of Winter samples and -8.8/+15.7 percent for the Summer samples.

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

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

However, as demonstrated above in Figure A-3, the amount of variation in C content of gasoline is restricted by the compounds in the fuel to ±4 percent. Further, despite variation in sampling survey response, sample size and annually variable fuel formulation requirements, the observed variation in the annual weighted motor gasoline coefficients estimated for this inventory is ±0.8 percent over 1990 through 2008.

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

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

Jet Fuel

Jet fuel is a refined petroleum product used in jet aircraft engines. There are two classes of jet fuel used in the United States: “naphtha-based” jet fuels and “kerosene-based” jet fuels. In 1989, 13 percent of U.S. consumption was naphtha-based fuel, with the remainder kerosene-based jet fuel. In 1993, the U.S. Department of Defense began a conversion from naphtha-based JP-4 jet fuel to kerosene-based jet fuel, because of the possibility of increased demand for reformulated motor gasoline limiting refinery production of naphtha-based jet fuel. By 1996, naphtha-based jet fuel represented less than one-half of one percent of all jet fuel consumption. The C content coefficient for jet fuel used in this report prior to 1996 represents a consumption-weighted combination of the naphtha-based and kerosene-based coefficients. From 1996 to 2008, only the kerosene-based portion of total consumption is considered significant.

Methodology

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

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

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

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

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

For years 1990 through 1995, the C content for each jet fuel type (naphtha-based, kerosene-based) is multiplied by the share of overall consumption of that fuel type, as reported by EIA (2009a). Individual coefficients are then summed and totaled to yield an overall C content coefficient. Only the kerosene-based C coefficient is reflected in the overall jet fuel coefficient for 1996 through 2008.

Data Sources

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

Uncertainty

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

Distillate Fuel

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

Methodology

For this inventory, separate C coefficients have been estimated for each of the three distillates, although the level of aggregation of U.S. energy statistics requires that a single coefficient is used to represent all three grades in inventory calculations. In past inventories, the emission coefficient was only determined for distillate No. 2. Distillate No. 2 remains the representative grade applied to the distillate class for calculation purposes. Coefficients developed for No. 1 and No. 4 distillate are provided for informational purposes. The C share each distillate is drawn from Perry's Chemical Engineers' Handbook, 8th Ed. (Green & Perry 2008). Each C share was combined with individual heat contents of 5.822, 5.809 and 6.135 MMBtu per barrel, respectively for distillates No. 1, No. 2 and No. 4, and densities of 35.3, 35.8 and 23.2 degrees API to calculate C coefficients for each distillate type.

Data Sources

Densities for distillate Nos. 1 and 2 were derived from Alliance of Automobile Manufacturers, Diesel Survey – Winter 2008 (AAM 2009). Densities are based on four, and 144 samples, respectively. The density of distillate fuel oil No. 4 is taken from Perry's Chemical Engineer's Handbook, 8th Ed. (Green & Perry, 2008), Table 24-6.

Heat contents are adopted from EPA (2009b). And carbon shares for each distillate are from Perry's Chemical Engineers' Handbook (Green & Perry 2008), Table 24-6.

Uncertainty

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

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

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

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

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

Residual Fuel

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

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

Methodology

Because U.S. energy consumption statistics are available only as an aggregate of No. 5 and No. 6 residual oil, a single coefficient must be used to represent the full residual fuel category. As in earlier editions of this report, residual fuel oil has been defined as No. 6 fuel oil, due to the majority of residual consumed in the United States being No. 6. However, for this report, a separate coefficient for fuel oil No. 5 has also been developed for informational purposes. Densities of 33.0 and 15.5 degrees API were adopted when developing the C content coefficients for Nos. 5 and 6, respectively (Wauquier, J.-P., ed. 1995; Green & Perry, ed. 2008).

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

Data Sources

Data on the C share and density of residual fuel oil No. 6 were obtained from Green & Perry, ed. (2008).

Data on the C share of fuel oil No. 5 was adopted from EIA (1994), and the density of No. 5 was obtained from Wauquier, J.-P., ed. (1995).

Heat contents for both Nos. 5 and 6 fuel oil are adopted from EPA (2009b).

Uncertainty

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

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

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 C shares are easily derived by taking into account the atomic weight of C (12.01) and the atomic weight of hydrogen (1.01). Thus, for example, the C share of propane, C_3H_8, is 81.71 percent. The densities and heat contents of the compounds are also well known, allowing C content coefficients to be calculated directly. Table A-49 summarizes the physical characteristic of LPG.

Table A-49: 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 C/QBtu)
Ethane	C_2H_6	11.55	79.89	3.082	17.16
Propane	C_3H_8	12.76	81.71	3.836	16.76
Isobutane	C_4H_{10}	11.42	82.66	3.974	17.77
n-butane	C_4H_{10}	10.98	82.66	4.326	17.75

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

Methodology

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

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

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

A C content coefficient for LPG used as fuel is developed based on the consumption mix of the individual compounds 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 C content coefficient for LPG used for non-fuel applications is developed based on the consumption mix of the individual compounds reported in U.S. energy statistics.

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

The changing shares of LPG fuel use and non-fuel use consumption appear below in Table A- 50.

Data Sources

Data on C share was derived via calculations based on atomic weights of each element of the four individual compounds densities are from the CRC Handbook of Chemistry and Physics, 89th Education. The energy content of each LPG is from the EPA (2009b). LPG consumption was based on data obtained from API (1990 through 2008) and EIA (2009b). Non-fuel use of LPG was obtained from API (1990 through 2008).

Uncertainty

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

Table A- 50: Consumption and Carbon Content Coefficients of Liquefied Petroleum Gases, 1990-2011

	1990		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Energy Consumption (QBtu)															
Fuel Use	**0.88**		**1.31**	**1.16**	**1.25**	**1.22**	**1.26**	**1.21**	**1.19**	**1.20**	**1.13**	**1.13**	**1.16**	**1.16**	**1.16**
Ethane	0.04		0.10	0.06	0.06	0.06	0.06	0.06	0.06	0.07	0.06	0.07	0.08	0.08	0.08
Propane	0.77		1.07	1.00	1.10	1.07	1.12	1.08	1.07	1.09	1.02	1.02	1.02	1.02	1.02
Butane	0.06		0.07	0.06	0.05	0.06	0.06	0.05	0.05	0.05	0.05	0.03	0.05	0.05	0.05
Isobutane	0.01		0.06	0.04	0.04	0.03	0.01	0.01	0.01	0.00	0.00	0.01	0.01	0.01	0.01
Non-Fuel Use	**1.35**		**1.90**	**1.77**	**1.85**	**1.75**	**1.80**	**1.70**	**1.74**	**1.78**	**1.67**	**1.80**	**1.96**	**1.96**	**1.96**

Ethane	0.71		1.04	0.96	1.00	0.92	0.97	0.91	0.98	1.03	0.95	1.12	1.22	1.22	1.22
Propane	0.51		0.65	0.59	0.64	0.63	0.66	0.63	0.63	0.64	0.60	0.60	0.60	0.60	0.60
Butane	0.11		0.11	0.13	0.12	0.13	0.13	0.12	0.12	0.11	0.12	0.08	0.12	0.12	0.12
Isobutane	0.02		0.09	0.09	0.08	0.07	0.03	0.03	0.02	0.01	0.00	0.01	0.03	0.03	0.03
Carbon Content (Tg C/QBtu)															
Fuel Use	16.86		16.89	16.87	16.85	16.86	16.84	16.84	16.83	16.82	16.83	16.82	16.82	16.82	16.82
Non-Fuel Use	17.06		17.09	17.10	17.09	17.09	17.07	17.06	17.06	17.05	17.06	17.06	17.06	17.06	17.06

Sources: Fuel use of LPG based on data from EIA (2009b) and API (1990 through 2007). Non-fuel use of LPG from API (1990 through 2008). Volumes converted using the energy contents provided in Table A-49. C contents from EPA (2010).

Aviation Gasoline

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

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

Methodology

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

Data Sources

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

Uncertainty

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

Still Gas

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

Methodology

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

Data Sources

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

Uncertainty

The EIA obtained data on four samples of still gas. Table A-51 below shows the composition of those samples.

Table A-51: 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 C/QBtu)
One	12.7	28.1	17.1	11.9	1,388	17.51
Two	34.7	20.5	20.5	6.7	1,143	14.33
Three	72.0	12.8	10.3	3.8	672	10.23
Four	17.0	31.0	16.2	2.4	1,100	15.99

Sources: EIA (2008b).

Because the composition of still gas is highly heterogeneous, the C content coefficient for this product is highly uncertain. Gas streams with a large, free-hydrogen content are likely to be used as refinery or chemical feedstocks. Therefore, the sample cited above with the very high H content of 72 percent (and the lowest calculated C content) is less likely to be representative of the still gas streams to which the calculated coefficient is applied. The C content coefficient used for this report is probably at the high end of the plausible range given that it is higher than the greatest sample-based C content in Table A-51.

Asphalt

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

Methodology

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

Data Sources

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

Uncertainty

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

Lubricants

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

Methodology

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

Data Sources

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

Uncertainty

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

Petrochemical Feedstocks

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

Methodology

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

Step 1. Estimate the carbon content coefficient for naphtha

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

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

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

Data Sources

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

Uncertainty

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

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

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

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

Kerosene

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

Methodology

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

Data Sources

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

Uncertainty

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

Petroleum Coke

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

Methodology

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

Data Sources

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

Uncertainty

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

Special Naphtha

Special naphtha is defined as a light petroleum product to be used for solvent applications, including commercial hexane and four classes of solvent: 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 C percentage, requiring the development of multiple coefficients.

Methodology

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

Step 1. Estimate the carbon content coefficient for hexane

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

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

The hydrocarbon compounds in special naphthas are assumed to be either paraffinic or aromatic (see discussion above). The portion of aromatics in odorless solvents is estimated at less than 1 percent, Stoddard and high flash point solvents contain 15 percent aromatics and high solvency mineral spirits contain 30 percent aromatics (Boldt and Hall 1977). These assumptions, when combined with the relevant densities, yield the C content factors contained in Table A-52, below.

Table A-52: Characteristics of Non-hexane Special Naphthas

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

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

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

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

Data Sources

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

Uncertainty

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

Petroleum Waxes

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

Methodology

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

Step 1. Estimate the carbon content of paraffin waxes

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

Step 2. Estimate the carbon content of microcrystalline waxes

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

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

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

Data Sources

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

Uncertainty

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

Crude Oil, Unfinished Oils, and Miscellaneous Products

U.S. energy statistics include several categories of petroleum products designed to ensure that reported refinery accounts "balance" and cover any "loopholes" in the taxonomy of petroleum products. These categories include crude oil, unfinished oils, and miscellaneous products. Crude oil is rarely consumed directly, miscellaneous products account for less than one percent of oil consumption, and unfinished oils are a balancing item that may show negative consumption. For C accounting purposes, it was assumed that all these products have the same C 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 C content based on this information, results of ultimate analyses of 182 crude oil samples were collected. Within the sample set, C content ranged from 82 to 88 percent C, but almost all samples fell between 84 percent and 86 percent C. The density and sulfur content of the crude oil data were regressed on the C content, producing the following equation:

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

Absent the term representing sulfur content, the equation had an R-squared of only 0.35.[23] When C content was adjusted to exclude sulfur, the R-squared value rose to 0.65. While sulfur is the most important non-hydrocarbon impurity, nitrogen and oxygen can also be significant, but they do not seem to be correlated with either density or sulfur content. Restating these results, density accounts for about 35 percent of the variation in C content, impurities account for about 30 percent of the variation, and the remaining 35 percent is accounted for by other factors, including (presumably) the degree to which aromatics and polynuclear aromatics are present in the crude oil. Applying this equation to the 2008 crude oil quality data (30.21 degrees API and 1.47 percent sulfur) produces an estimated C content of 84.79 percent. Applying the density and C content to the EIA standard energy content for crude oil of 5.800 MMBtu per barrel produced an emissions coefficient of 20.31 Tg C/QBtu.

Data Sources

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

Uncertainty

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

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

Coal

Original 1994 Analysis

A set of 5,426 coal samples from the EIA coal analysis file were used to develop C content estimates. The results from that sample set appear below in Table A-53. 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.

Table A-53: Carbon Content Coefficients for Coal by Consuming Sector and Coal Rank, 1990 – 2000 (Tg C/QBtu)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Consuming Sector											
Electric Power	25.68	25.69	25.69	26.71	25.72	25.74	25.74	25.76	25.76	25.76	25.76
Industrial Coking	25.51	25.51	25.51	25.51	25.52	25.53	25.55	25.56	25.56	25.56	25.56
Other Industrial	25.58	25.59	25.62	25.61	25.63	25.63	25.61	25.63	25.63	25.63	25.63
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 be consuming sector from B.D. Hong and E.R. Slatnick, "Carbon Dioxide Emission Factors for Coal, " U.S. Energy Information Administration, *Quarterly Coal Report*, January-March 1994. (Washington, DC, 1994) and Emission factors by rank from Science Applications International Corporation, "Analysis of the Relationship Between Heat and Carbon Content of U.S. Fuels: Final Task Report," Prepared for the U.S. Energy Information Administration, Office of Coal, Nuclear, Electric and Alternative Fuels (Washington, DC 1992).

2002 Update

The methodology employed for these estimates was unchanged from previous years; however, the underlying coal data sample set was updated. A new database, CoalQual 2.0 (1998), compiled by the U.S. Geological Survey was adopted for the updated analysis. The updated sample set included 6,588 coal samples collected by the USGS and its state

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

affiliates between 1973 and 1989. The decision to switch to the sample data contained in the USGS CoalQual database from the EIA database was made because the samples contained in the USGS database were collected and analyzed more recently than those obtained by EIA from the Bureau of Mines. The new coefficients developed in the 2002 revision were in use through the 1990 through 2007 Inventory and are provided in Table A-54.

Table A-54: Carbon Content Coefficients for Coal by Consuming Sector and Coal Rank, 1990 – 2000 (Tg C/QBtu)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Consuming Sector											
Electric Power	25.68	25.69	25.69	25.71	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	25.60	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	28.26	28.26	28.26	28.26	28.26	28.26	28.26	28.26	28.26	28.26	28.26
Bituminous	25.43	25.45	25.44	25.45	25.46	25.47	25.47	25.48	25.47	25.48	25.49
Sub-bituminous	26.50	26.49	26.49	26.48	26.49	26.49	26.49	26.49	26.49	26.49	26.48
Lignite	26.19	26.21	26.22	26.21	26.24	26.22	26.17	26.20	26.23	26.26	26.30

Sources: Data from USGS, U.S. Coal Quality Database Version 2.0 (1998) and analysis prepared by SAIC 2007.

2007 Update

The analysis of the USGS Coal Qual data was updated in 2007 to make a technical correction that affected the value for lignite and those sectors which consume lignite Table A-55 contains the annual coefficients that resulted from the 2007 analysis.

Table A-55: Carbon Content Coefficients for Coal by Consuming Sector and Coal Rank, 1990-2007 (Tg C/QBtu)

	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Consuming Sector														
Electric Power	25.68	25.74	25.74	25.76	25.76	25.76	25.76	25.76	25.76	25.76	25.76	25.76	25.76	25.76
Industrial Coking	25.51	25.53	25.55	25.56	25.56	25.56	25.56	25.56	25.56	25.56	25.56	25.56	25.56	25.56
Other Industrial	25.58	25.63	25.61	25.63	25.63	25.63	25.63	25.63	25.63	25.63	25.63	25.63	25.63	25.63
Residential/Commercial	25.92	26.00	25.92	26.00	26.00	26.00	26.00	26.00	26.00	26.00	26.00	26.00	26.00	26.00
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	28.26	28.26
Bituminous	25.43	25.47	25.47	25.48	25.47	25.48	25.49	25.49	25.49	25.49	25.49	25.49	25.49	25.49
Sub-bituminous	26.50	26.49	26.49	26.49	26.49	26.49	26.48	26.48	26.48	26.48	26.48	26.48	26.48	26.48
Lignite	26.19	26.22	26.17	26.20	26.23	26.26	26.30	26.30	26.30	26.30	26.30	26.30	26.30	26.57

Sources: Data from USGS, U.S. Coal Quality Database Version 2.0 (1998) and analysis prepared by (SAIC 2007).

2010 Update

The estimated annual C content coefficients for coal by rank and sector of consumption were updated again in 2010. Sample data from the Energy Institute at Pennsylvania State University (504 samples) were added to the 6,588 USGS samples to create a new database of 7,092 samples. The same analytical method used in the 2002 update was applied using these additional samples to calculate revised state-level carbon contents for each coal rank and then for national average consumption by end-use sector and by rank.

Natural Gas

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

The current Inventory is revised to make use of the same set of samples, but utilizes a regression equation, as described above, of sample-based heat content and carbon content data in order to calculate annually-variable national average C content coefficients based on annual national average heat contents for pipeline natural gas and for flare gas. In addition, the revised analysis calculates an average C content from all samples with less than 1.5 percent CO_2 and less than 1,050 Btu/cf (samples most closely approximating the makeup of pipeline quality natural gas). The result was identical to the previous weighted national average of 14.47 Tg C/QBtu. The average C contents from the 1994 calculations are presented in Table A-56 below for comparison.

Table A-56: Carbon Content of Pipeline-Quality Natural Gas by Energy Content (Tg C/QBtu)

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

Source: EIA (1994).

Petroleum Products

All of the petroleum product C coefficients except that for Aviation Gasoline Blending Components have been updated for the current Inventory. EPA is updating these factors to better align the fuel properties data that underlie the Inventory factors with those published in the Mandatory Reporting of Greenhouse Gases Rule (EPA 2009b), Suppliers of Petroleum Products (MM) and Stationary Combustion (C) subparts. The coefficients that were applied in the previous report are provided in Table A-57 below. Specifically, each of the coefficients used in this report have been calculated from updated density and C share data, largely adopted from analyses undertaken for the Rule (EPA 2009b). In some cases, the heat content applied to the conversion to a carbon-per-unit-energy basis has also been updated. Additionally, the category Misc. Products (Territories), which is based upon the coefficients calculated for crude oil, has been allowed to vary annually with the crude oil coefficient. The petrochemical feedstock category has been eliminated for this report because the constituent products—naphthas and other oils—are estimated independently. Further, although the level of aggregation of U.S. energy statistics currently limits the application of coefficients for residual and distillate fuels to these two generic classifications, individual coefficients for the five major types of fuel oil (Nos. 1, 2, 4, 5 and 6) have been estimated for the current report and are presented in Table A-46 above. Each of the C coefficients applied in the previous Inventory is provided below for comparison (Table A-57).

Table A-57: Carbon Content Coefficients and Underlying Data for Petroleum Products

Fuel	2007 Carbon Content (Tg C/QBtu)	Gross Heat of Combustion (MMBtu/Barrel)	Density (API Gravity)	Percent Carbon
Motor Gasoline	19.33	5.219	59.1	86.60
LPG (total)[a]	16.99	(See a)	(See a)	(See a)
LPG (energy use)	17.18	(See a)	(See a)	(See a)
LPG (non-energy use)	16.76	(See a)	(See a)	(See 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	20.33	5.800	30.5	85.49
Unfinished Oils	20.33	5.825	30.5	85.49
Miscellaneous Products	20.33	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 Heat, density and percent carbon values are provided separately for ethane, propane and isobutene.

[a] LPG is a blend of multiple paraffinic hydrocarbons: ethane, propane, isobutane, and normal butane, each with their own heat content, density and C content, see Table A-49.

[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), EIA (2008a), and SAIC (2007).

Additional revisions to the inventory's C coefficients since 1990 are detailed below.

Jet Fuel

1995 Update

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

1990 through 2008 Inventory Update

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

Liquefied Petroleum Gases (LPG)

The C 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 C per unit of energy, its removal from the consumption mix lowered the C content coefficient for LPG from 17.26 Tg C/QBtu to 16.99 Tg C/QBtu. In 1998, EIA began separating LPG consumption into two categories: energy use and non-fuel use and providing individual coefficients for each. Because LPG for fuel use typically contains higher proportions of propane than LPG for non-fuel use, the C content coefficient for fuel use was 1.8 to 2.5 percent higher than the coefficient for non-fuel use in previous Inventories (see Table A-57).

However, for the current update of the LPG coefficients, the assumptions that underlie the selection of density and heat content data for each pure LPG compound have been updated, leading to a significant revision of the assumed properties of ethane. For this report, the physical characteristics of ethane, which constitutes over 90 percent of LPG consumption for non-fuel uses, have been updated to reflect ethane that is in (refrigerated) liquid form. Previously, the share of ethane was included using the density and energy content of gaseous ethane. Table A-58, below, compares the values applied for each of the compounds under the two sets of coefficient calculations. The carbon share of each pure compound was also updated by using more precise values for each compound's molecular weight.

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

Table A-58: Physical Characteristics of Liquefied Petroleum Gases

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

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

Motor Gasoline

The C content coefficient for motor gasoline varies annually based on the density of and proportion of additives in a representative sample of motor gasoline examined each year. However, in 1997 EIA began incorporating the effects of the introduction of reformulated gasoline into its estimate of C content coefficients for motor gasoline. This change resulted in a downward step function in C content coefficients for gasoline of approximately 0.3 percent beginning in 1995. In 2005-2006 reformulated fuels containing ethers began to be phased out nationally. Ethanol was added to gasoline blends as a replacement oxygenate, leading to another shift in gasoline density (see Table A- 47), in the list and proportion of constituents that form the blend and in the blended C share based on those constituents.

Table A-59: Carbon Content Coefficients for Petroleum Products, 1990-2007 [Tg C/QBtu]

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

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

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

Carbon (C) storage associated with the non-energy use of fossil fuels was calculated by multiplying each fuel's potential emissions (i.e., each fuel's total C content) by a fuel-specific storage factor, as listed in Table A-60. The remaining C—i.e., that which is not stored—is emitted. This sub-annex explains the methods and data sources employed in developing the storage factors for petrochemical feedstocks (industrial other coal, natural gas for non-fertilizer uses, LPG, pentanes plus, naphthas, other oils, still gas, special naphtha), asphalt and road oil, lubricants, waxes, and miscellaneous products. The storage factors[24] for the remaining non-energy fuel uses are either based on values recommended for use by IPCC (2006), or when these were not available, assumptions based on the potential fate of C in the respective NEU products.

Table A-60: Fuel Types and Percent of C Stored for Non-Energy Uses

Sector/Fuel Type	Storage Factor (%)
Industry	-
Industrial Coking Coal [a]	10
Industrial Other Coal [b]	70
Natural Gas to Chemical Plants [b]	70
Asphalt & Road Oil	100
LPG [b]	70
Lubricants	9
Pentanes Plus [b]	70
Naphtha (<401 deg. F) [b]	70
Other Oil (>401 deg. F) [b]	70
Still Gas [b]	70
Petroleum Coke [c]	30
Special Naphtha [b]	70
Distillate Fuel Oil	50
Waxes	58
Miscellaneous Products	0
Transportation	-
Lubricants	9
U.S. Territories	-
Lubricants	9
Other Petroleum (Misc. Prod.)	10

- 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] The storage factor listed is the value for 2012. As described in this annex, the factor varies over time.

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

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

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

Petrochemical Feedstocks

Petrochemical feedstocks—industrial other coal, natural gas for non-fertilizer uses, LPG, pentanes plus, naphthas, other oils, still gas, special naphtha—are used in the manufacture of a wide variety of man-made chemicals and products. Plastics, rubber, synthetic fibers, solvents, paints, fertilizers, pharmaceuticals, and food additives are just a few of the derivatives of these fuel types. Chemically speaking, these fuels are diverse, ranging from simple natural gas (i.e., predominantly CH_4) to heavier, more complex naphthas and other oils.[25]

After adjustments for (1) use in industrial processes and (2) net exports, these eight fuel categories constituted approximately 197.3 Tg CO_2 Eq., or 62 percent, of the 315.8 Tg CO_2 Eq. of non-energy fuel consumption in 2012. For 2012, the storage factor for the eight fuel categories was 70 percent. In other words, of the net consumption, 70 percent was destined for long-term storage in products—including products subsequently combusted for waste disposal—while the remaining 30 percent was emitted to the atmosphere directly as CO_2 (e.g., through combustion of industrial by-products) or indirectly as CO_2 precursors (e.g., through evaporative product use). The indirect emissions include a variety of organic gases such as volatile organic compounds (VOCs) and carbon monoxide (CO), which eventually oxidize into CO_2 in the atmosphere. The derivation of the storage factor is described in the following sections.

Methodology and Data Sources

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

Import and export data for feedstocks were obtained from the Energy Information Administration (EIA) for the major categories of petrochemical feedstocks. EIA's *Petroleum Supply Annual* publication tracks imports and exports of petrochemical feedstocks, including 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), which are derived from the primary chemicals produced by the refineries. These products represent very large flows of C derived from fossil fuels (i.e., fossil C), so estimates of net flows not already considered in EIA's dataset were developed for the entire time series from 1990 to 2012.

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

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

Step 2. Estimate the C content for each commodity.

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

Step 1 relies heavily on information provided by the National Petrochemical and Refiners Association (NPRA) and U.S. Bureau of the Census (BoC) trade statistics published by the U.S. International Trade Commission (USITC). NPRA provided a spreadsheet of the ten-digit BoC Harmonized Tariff Schedule (HTS) Commodity Codes used to compile import-export data for periodic reports issued to NPRA's membership on trade issues. Additional feedstock commodities were identified by HTS code in the BoC data system and included in the net import/export analysis.

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

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[25] 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.

EIA data. Imports and exports of commodities for which production and consumption data are provided by EIA (e.g., butane, ethylene, and liquefied petroleum gases) are also not included in the totals, to avoid double-counting.

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

The BoC trade statistics are publicly available[26] and cover a complete time series from 1990 to 2012. These statistics include information on imports and exports of thousands of commodities. After collecting information on annual flows of the more than 100 commodities identified by NPRA, Step 2 involves calculating the C content for each commodity from its chemical formula. In cases where the imports and exports were expressed in units of volume, rather than mass, they were converted to mass based on the commodities' densities.

Step 3 involves summing the net C imports/exports across all commodities. The results of this step are shown in Table A-61. As shown in the table, the United States has been a net exporter of chemical intermediates and products throughout the 1990 to 2012 period.

Table A-61: Net Exports of Petrochemical Feedstocks, 1990 – 2012 (Tg CO_2 Eq.)

	1990	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Net Exports	12.0	11.1	8.3	1.8	7.3	14.8	20.2	6.5	4.1	8.4	4.5	9.0	7.7	8.3	9.8

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

For each year of the Inventory, the total C content of non-energy uses was calculated by starting with the EIA estimate of non-energy use, and reducing it by the adjustment factor for net exports (see Table A-61) to yield net domestic fuel consumption for non-energy. The balance was apportioned to either stored C or emissive C, based on a storage factor.

The overall storage factor for the feedstocks was determined by developing a mass balance on the C in feedstocks, and characterizing products, uses, and environmental releases as resulting in either storage or emissions. The total C in the system was estimated by multiplying net domestic consumption for non-energy by the C content of each of the feedstocks (i.e., industrial other coal, natural gas for non-fertilizer uses, LPG, pentanes plus, naphthas, other oils, still gas, special naphtha). C content values for the fuel feedstocks are discussed in the Estimating Emissions from Fossil Fuel Combustion and Estimating the Carbon Content from Fossil Fuel Combustion Annexes.

Next, C pools and releases in a variety of industrial releases, energy recovery processes, and products were characterized. The C fate categories are plastics, energy recovery, synthetic rubber, synthetic fibers, organic solvents, C black, detergents and personal cleansers, industrial non-methane volatile organic compound (NMVOC) emissions, hazardous waste incineration, industrial toxic chemical (i.e., TRI) releases, pesticides, food additives, antifreeze and deicers (glycols), and silicones.[27]

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

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

The C in each product or waste produced was categorized as either stored or emitted. The aggregate storage factor is the C-weighted average of storage across fuel types. As discussed later in the section on uncertainty, the sum of stored C and emitted C (i.e., the outputs of the system) exceeded total C consumption (i.e., the inputs to the system) for some years in the time series.[28] To address this mass imbalance, the storage factor was calculated as C storage divided by total C outputs (rather than C storage divided by C inputs).

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

The following sections provide details on the calculation steps, assumptions, and data sources employed in estimating and classifying the C in each product and waste shown in Table A-62. Summing the C stored and dividing it by total C outputs yields the overall storage factor, as shown in the following equation for 2012:

$$\text{Overall Storage Factor} = \text{C Stored} / (\text{C Stored} + \text{C Emitted}) =$$

$$136.7 \text{ Tg } CO_2 \text{ Eq.} / (136.7 + 60.3) \text{ Tg } CO_2 \text{ Eq.} = 70\%$$

Table A-62: C Stored and Emitted by Products from Feedstocks in 2012 (Tg CO_2 Eq.)

Product/Waste Type	C Stored (Tg CO_2 Eq.)	C Emitted (Tg CO_2 Eq.)
Industrial Releases	**0.1**	**5.2**
TRI Releases	0.1	1.0
Industrial VOCs	-	3.4
Non-combustion CO	-	0.5
Hazardous Waste Incin.	-	0.4
Energy Recovery	**-**	**41.3**
Products	**136.7**	**13.8**
Plastics	118.4	-
Synthetic Rubber	10.6	-
Antifreeze and deicers	-	0.7
Abraded tire rubber	-	0.3
Food additives	-	0.8
Silicones	0.5	-
Synthetic Fiber	6.9	-
Pesticides	0.2	0.2
Soaps, shampoos, detergents	-	6.5
Solvent VOCs	-	5.2
Total	**136.7**	**60.3**

- Not applicable

Note: Totals may not sum due to independent rounding.

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

Industrial Releases

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

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[28] Overall, there was fairly close agreement between inputs and outputs: for the entire 1990 through 2012 time series, inputs exceeded outputs by a time-weighted average of 0.2 percent. During the period 1990 through 2000, carbon inputs exceeded carbon outputs (i.e., the sum of carbon stored and carbon emitted) by a time-weighted average of 10 percent. For those years, the assumption was made that the “missing” carbon was lost through fates leading to emissions. This discrepancy shifted during the period from 2001 through 2012, in which carbon outputs exceeded carbon inputs by a time-weighted average of 12 percent.

TRI Releases

Fossil-derived C is found in many toxic substances released by industrial facilities. The Toxics 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 C contents and receiving media for the top 35 toxic chemicals released, which account for 90 percent of the total mass of chemicals, the quantity of C stored and emitted in the form of toxic releases can be estimated.

The TRI specifies releases by chemical, so C contents were assigned to each chemical based on molecular formula. The TRI also classifies releases by disposal location as either off-site or on-site. The on-site releases are further subdivided into air emissions, surface water discharges, underground injection, and releases to land; the latter is further broken down to disposal in a RCRA Subtitle C (i.e., hazardous waste) landfill or to "Other On-Site Land Disposal."[29] The C released in each disposal location is provided in Table A-63.

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

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

Data on TRI releases for the full 1990 through 2012 time series were not readily available. Since this category is small (less than 1 Tg C emitted and stored), the 1998 value was applied for the entire time series.

Table A-63: 1998 TRI Releases by Disposal Location (Gg CO_2 Eq.)

Disposal Location	Carbon Stored (Gg CO_2 Eq.)	Carbon Emitted (Gg CO_2 Eq.)
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 Emissions

Data on annual non-methane volatile organic compound (NMVOC) emissions were obtained from preliminary data (EPA 2013a), and disaggregated based on EPA (2003), which, in its final iteration, will be published on the National Emission Inventory (NEI) Air Pollutant Emission Trends web site. The 1990-2013 Trends data include information on NMVOC emissions by end-use category; some of these fall into the heading of "industrial releases" in Table A-63 above, and others are related to "product use"; for ease of discussion, both are covered here. The end-use categories that represent "Industrial NMVOC Emissions" include some chemical and allied products, certain petroleum related industries, and other industrial processes. NMVOC emissions from solvent utilization (product use) were considered to be a result of non-energy use of petrochemical feedstocks. These categories were used to distinguish non-energy uses from energy uses; other categories where VOCs could be emitted due to combustion of fossil fuels were excluded to avoid double counting. Data for 2012 are not yet available, so they have been set equal to 2011 values.

Because solvent evaporation and industrial NMVOC emission data are provided in tons of total NMVOCs, assumptions were made concerning the average C content of the NMVOCs for each category of emissions. The

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[29] 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).

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

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

The results of the industrial and solvent NMVOC emissions analysis are provided in Table A-64 for 1990 through 2012. Industrial NMVOC emissions in 2012 were 3.4 Tg CO_2 Eq. and solvent evaporation emissions in 2012 were 5.2 Tg CO_2 Eq.

Table A-64: Industrial and Solvent NMVOC Emissions

	1990	1995	2000	2005	2006	2007	2008	2009	2010	2011	2012
Industrial NMVOCs[a]											
NMVOCs ('000 Short Tons)	1,279	1,358	802	824	878	933	987	752	972	1,192	1,192
Carbon Content (%)	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Carbon Emitted (Tg CO_2 Eq.)	3.6	3.8	2.3	2.3	2.5	2.6	2.8	2.1	2.7	3.4	3.4
Solvent Evaporation[b]											
Solvents ('000 Short Tons)	5,750	6,183	4,832	4,245	3,930	3,614	3,298	3,129	2,959	2,790	2,790
Carbon Content (%)	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%
Carbon Emitted (Tg CO_2 Eq.)	10.8	11.6	9.0	7.9	7.4	6.8	6.2	5.9	5.5	5.2	5.2

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

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

Non-Combustion Carbon Monoxide Emissions

Carbon monoxide (CO) emissions data were also obtained from the NEI preliminary data (EPA 2013a), and disaggregated based on EPA (2003). There are three categories of CO emissions in the report that are classified as process-related emissions not related to fuel combustion. These include chemical and allied products manufacturing, metals processing, and other industrial processes. Some of these CO emissions are accounted for in the Industrial Processes section of this report, and are therefore not accounted for in this section. These include total C emissions from the primary aluminum, titanium dioxide, iron and steel, and ferroalloys production processes. The total C (CO and CO_2) emissions from oil and gas production, petroleum refining, and asphalt manufacturing are also accounted for elsewhere in this Inventory. Biogenic emissions (e.g., pulp and paper process emissions) are accounted for in the Land Use, Land-Use Change and Forestry chapter and excluded from calculation of CO emissions in this section. Those CO emissions that are not accounted for elsewhere are considered to be by-products of non-fuel use of feedstocks, and are thus included in the calculation of the petrochemical feedstocks storage factor. Table A-65 lists the CO emissions that remain after taking into account the exclusions listed above. As data for 2012 are not yet available, they have been set equal to 2011 values.

Table A-65: Non-Combustion Carbon Monoxide Emissions

	1990	1995	2000	2005	2006	2007	2008	2009	2010	2011	2012
Thousand short tons CO	489	481	623	461	443	426	408	461	405	348	348
Carbon Emitted (Tg CO_2 Eq.)	0.7	0.7	0.9	0.7	0.6	0.6	0.6	0.7	0.6	0.5	0.5

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

Hazardous Waste Incineration

Hazardous wastes are defined by the EPA under the Resource Conservation and Recovery Act (RCRA).[30] 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 United States is burned in BIFs; because these processes are included in the energy recovery calculations described below, they are not included as part of hazardous waste incineration.

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

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

Waste quantity data for hazardous wastes were obtained from EPA's RCRA Information/BRS database for reporting years 1989, 1991, 1993, 1995, 1997, 1999, 2001, 2003, 2005, 2007, 2009, and 2011 (EPA 2000a, 2009, 2013b). Combusted waste quantities were obtained from Form GM (Generation and Management) for wastes burned on site and Form WR (Wastes Received) for waste received from off-site for combustion. For each of the waste types, assumptions were developed on average waste composition (see Table A-66). Regulations require incinerators to achieve at least 99.99 percent destruction of organics; this formed the basis for assuming the fraction of C oxidized. Emissions from hazardous waste incineration in 2012 were 0.4 Tg CO_2 Eq. Table A-67 lists the CO_2 emissions from hazardous waste incineration.

Table A-66: Assumed Composition of Combusted Hazardous Waste by Weight (Percent)

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

Table A-67: CO_2 Emitted from Hazardous Waste Incineration (Tg CO_2 Eq.)

	1990	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
C Emissions	1.1	1.7	1.0	0.6	0.6	0.6	0.6	0.6	0.5	0.4	0.4	0.3	0.3	0.4	0.4

Energy Recovery

The amount of feedstocks combusted for energy recovery was estimated from data included in EIA's Manufacturers Energy Consumption Survey (MECS) for 1991, 1994, 1998, 2002, and 2006 (EIA 1994, 1997, 2001, 2005, 2010, 2013b). Some fraction of the fossil C exiting refineries and designated for use for feedstock purposes actually ends up being combusted for energy recovery (despite the designation of feedstocks as a "non-energy" use) because the chemical reactions in which fuel feedstocks are used are not 100 percent efficient. These chemical reactions may generate

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[30] [42 U.S.C. §6924, SDWA §3004]

unreacted raw material feedstocks or generate by-products that have a high energy content. The chemical industry and many downstream industries are energy-intensive and often have boilers or other energy recovery units on-site, and thus these unreacted feedstocks or by-products are often combusted for energy recovery. Also, as noted above in the section on hazardous waste incineration, regulations provide a strong incentive—and in some cases require—burning of organic wastes generated from chemical production processes.

Information available from the MECS include data on the consumption for energy recovery of "other" fuels in the petroleum and coal products, chemicals, primary metals, nonmetallic minerals, and other manufacturing sectors. These "other" fuels include refinery still gas; waste gas; waste oils, tars, and related materials; petroleum coke, coke oven and blast furnace gases; scrap tires; liquor or black liquor; woodchips and bark; and other uncharacterized fuels. Fuel use of petroleum coke is included separately in the fuel use data provided annually by EIA, and energy recovery of coke oven gas and blast furnace gas (i.e., by-products of the iron and steel production process) is addressed in the Iron and Steel production section in the Industrial Processes chapter. Consumption of refinery still gas in the refinery sector is also included separately in the fuel use data from EIA. The combustion of scrap tires in cement kilns, lime kilns, and electric arc furnaces is accounted for in the Waste Incineration chapter; data from the Rubber Manufacturers Association (RMA 2009a) were used to difference out energy recovery from scrap tires in these industries. Consumption of net steam, assumed to be generated from fossil fuel combustion, is also included separately in the fuel use data from EIA. Therefore, these categories of "other" fuels are addressed elsewhere in the Inventory and not considered as part of the petrochemical feedstocks energy recovery analysis. Liquor or black liquor and woodchips and bark are assumed to be biogenic fuels, in accordance with IPCC (2006), and therefore are not included in the Inventory. The remaining categories of fuels, including waste gas; waste oils, tars, and related materials; and other uncharacterized fuels are assumed to be petrochemical feedstocks burned for energy recovery (see Table A-68). The conversion factors listed in the Estimating Emissions from Fossil Fuel Combustion Annex were used to convert the Btu values for each fuel feedstock to Tg CO_2. Petrochemical feedstocks combusted for energy recovery corresponded to 42.5 Tg CO_2 Eq. in 1991, 35.1 Tg CO_2 Eq. in 1994, 58.0 Tg CO_2 Eq. in 1998, 70.6 Tg CO_2 Eq. in 2002, 74.8 Tg CO_2 Eq. in 2006, and 41.3 Tg CO_2 Eq. in 2010. Values for petrochemical feedstocks burned for energy recovery for years between 1991 and 1994, between 1994 and 1998, between 1998 and 2002, between 2002 and 2006, and between 2007 and 2010 have been estimated by linear interpolation. The value for 1990 is assumed to be the same as the value for 1991, and 2011 and 2012 are assumed to be the same as the value for 2010 (Table A-69).

Table A-68: Summary of 2010 MECS Data for Other Fuels Used in Manufacturing/Energy Recovery (Trillion Btu)

Subsector and Industry	NAICS CODE	Waste Gas[a]	Waste Oils/Tars[b]	Refinery Still Gas[c]	Net Steam[d]	Other Fuels[e]
Printing and Related Support	323	0	0	0	0	0
Petroleum and Coal Products	324	0	6	1349	153	54
Chemicals	325	376	7	0	266	110
Plastics and Rubber Products	326	0	0	0	0	0
Nonmetallic Mineral Products	327	1	7	0	0	5
Primary Metals	331	0	0	0	12	34
Fabricated Metal Products	332	0	0	0	0	0
Machinery	333	0	0	0	0	1
Computer and Electronic Products	334	0	0	0	0	0
Electrical Equip., Appliances, Components	335	0	0	0	0	0
Transportation Equipment	336	2	0	0	0	3
Furniture and Related Products	337	0	0	0	0	0
Miscellaneous	339	0	0	0	0	0
Total (Trillion Btu)		**379**	**20**	**1349**	**432**	**205**
Average C Content (Tg/QBtu)		18.14	20.62	17.51	0	19.37
Fraction Oxidized		1	1	1	0	1
Total C (Tg)		**6.88**	**0.41**	**23.62**	**0.00**	**3.98**
Total C (Tg) (ex. still gas from refining)		**6.88**	**0.41**	**-**	**-**	**3.98**

- Not applicable

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

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

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

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

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

Table A-69: Carbon Emitted from Fuels Burned for Energy Recovery (Tg CO_2 Eq.)

	1990	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
C Emissions	42.5	40.8	64.3	67.4	70.6	71.6	72.7	73.7	74.8	66.4	58.1	49.7	41.3	41.3	41.3

Products

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

Plastics

Data on annual production of plastics through 2005 were taken from the American Plastics Council (APC), as published in *Chemical & Engineering News* and on the APC and Society of Plastics Industry (SPI) websites, and through direct communication with the APC (APC 2000, 2001, 2003 through 2006; SPI 2000; Eldredge-Roebuck 2000). Data for 2006 through 2012 were taken directly or derived from the American Chemistry Council (ACC 2007 through 2010 supplemented by Vallianos 2011, 2012, 2013). In 2009, the American Chemistry Council consolidated the resin categories for which it reports plastics production. Production numbers in the original categories were provided via personal correspondence for 2009, 2011, and 2012 (Vallianos 2011, 2012, 2013). Production figures for the consolidated resin categories in 2010 were linearly interpolated from 2009 and 2011 data. Production was organized by resin type (see Table A-70) and by year.

Several of the resin categories included production from Canada and/or Mexico, in addition to the U.S. values for part of the time series. The production data for the affected resins and years were corrected using an economic adjustment factor, based on the percent of North American production value in this industry sector accounted for by the United States. A C content was then assigned for each resin. These C contents were based on molecular formulae and are listed in Table A-71 and Table A-72. In cases where the resin type is generic, referring to a group of chemicals and not a single polymer (e.g., phenolic resins, other styrenic resins), a representative compound was chosen. For other resins, a weighted C content of 68 percent was assumed (i.e., it was assumed that these resins had the same content as those for which a representative compound could be assigned).

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

Table A-70: 2012 Plastic Resin Production (Tg dry weight) and C Stored (Tg CO_2 Eq.)

Resin Type	2012 Production[a] (Tg dry weight)	Carbon Stored (Tg CO_2 Eq.)
Epoxy	0.3	0.8
Urea	0.5	0.6
Melamine	0.5	0.5
Phenolic	1.4	3.9
Low-Density Polyethylene (LDPE)	2.9	9.1
Linear Low-Density Polyethylene (LLDPE)	5.7	17.8
High Density Polyethylene (HDPE)	7.5	23.5
Polypropylene (PP)	6.7	21.1
Acrylonitrile-butadiene-styrene (ABS)	0.4	1.3
Other Styrenics[c]	0.5	1.7
Polystyrene (PS)	2.3	7.8
Nylon	0.5	1.2
Polyvinyl chloride (PVC)[b]	6.5	9.1
Thermoplastic Polyester	3.5	8.0
All Other (including Polyester (unsaturated))	5.7	14.5
Total	**44.8**	**120.9**

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

[b] Includes copolymers

[c] Includes Styrene-acrylonitrile (SAN)

Note: Totals may not sum due to independent rounding.

Table A-71: Assigned C Contents of Plastic Resins (% by weight)

Resin Type	C Content	Source of C Content Assumption
Epoxy	76%	Typical epoxy resin made from epichlorhydrin and bisphenol A
Polyester (Unsaturated)	63%	Poly (ethylene terephthalate) (PET)
Urea	34%	50% carbamal, 50% N-(hydroxymethyl) urea *
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 A-72)
Polyvinyl Chloride (PVC)	38%	Polyvinyl chloride
Thermoplastic Polyester	63%	Polyethylene terephthalate
All Other	69%	Weighted average of other resin production

*Does not include alcoholic hydrogens.

Table A-72: Major Nylon Resins and their C Contents (% by weight)

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

Synthetic Rubber

Data on synthetic rubber in tires were derived from data on the scrap tire market and the composition of scrap tires from the Rubber Manufacturers' Association (RMA). The market information is presented in the report *U.S. Scrap Tire Management Summary: 2005-2009* (RMA 2011), while the tire composition information is from the "Scrap Tires, Facts and Figures" section of the organization's website (RMA 2009). Data on synthetic rubber in other products (durable goods, nondurable goods, and containers and packaging) were obtained from EPA's *Municipal Solid Waste in the United States* reports (1996 through 2003a, 2005, 2007b, 2008, 2009a, 2011a, 2013c; 2014) and detailed unpublished backup data for some years not shown in the *Characterization of Municipal Solid Waste in the United States* reports (Schneider 2007). The abraded rubber from scrap passenger tires was assumed to be 2.5 lbs per scrap tire, while the abraded rubber from scrap commercial tires was assumed to be 10 lbs per scrap tire. Data on abraded rubber weight were obtained by calculating the average weight difference between new and scrap tires (RMA 20011). RMA data were not yet available for 2010 through 2012, so they were set equal to 2009 values.

A C content for synthetic rubber (90 percent for tire synthetic rubber and 85 percent for non-tire synthetic rubber) was assigned based on the weighted average of C contents (based on molecular formula) by elastomer type consumed in 1998, 2001, and 2002 (see Table A-73). The 1998 consumption data were obtained from the International Institute of Synthetic Rubber Producers (IISRP) press release "Synthetic Rubber Use Growth to Continue Through 2004, Says IISRP and RMA" (IISRP 2000). The 2001 and 2002 consumption data were obtained from the IISRP press release, "IISRP Forecasts Moderate Growth in North America to 2007" (IISRP 2003).

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

Table A-73: 2002 Rubber Consumption (Gg) and C Content (%)

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

* 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* (FEB 2001, 2003, 2005, 2007, 2009, 2010, 2011, 2012, 2013). These data are organized by year and fiber type. For each fiber, a C content was assigned based on molecular formula (see Table A-74). For polyester, the C content for poly (ethylene terephthalate) (PET) was used as a representative compound. For nylon, the average C content of nylon 6 and nylon 6.6 was used, since these are the most widely produced nylon fibers. Cellulosic fibers, such as acetate and rayon, have been omitted from the synthetic fibers' C accounting displayed here because much of their C is of biogenic origin and carbon fluxes from biogenic compounds are accounted for in the Land Use, Land-Use Change and Forestry chapter. These fibers account for only 4 percent of overall fiber production by weight.

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

Table A-74: 2012 Fiber Production (Tg), C Content (%), and C Stored (Tg CO_2 Eq.)

Fiber Type	Production (Tg)	C Content	C Stored (Tg CO_2 Eq.)
Polyester	1.2	63%	2.8
Nylon	0.6	64%	1.3
Olefin	1.0	86%	3.2
Acrylic	+	68%	0.1
Total	**2.8**	**-**	**7.3**

+ Less than 0.05 Tg
- Not applicable
Note: Totals may not sum due to independent rounding

Pesticides

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

Table A-75: Active Ingredient Consumption in Pesticides (Million lbs.) and C Emitted and Stored (Tg CO_2 Eq.) in 2007

Pesticide Use*	Active Ingredient (Million lbs.)	C Emitted (Tg CO_2 Eq.)	C Stored (Tg CO_2 Eq.)
Agricultural Uses	473.5	0.1	0.1
Non-Agricultural Uses	76.8	+	+
Home & Garden	30.3	+	+
Industry/Gov't/Commercial	46.5	+	+
Other	337.7	0.1	0.1
Total	**888.0**	**0.2**	**0.2**

+ Less than 0.05 Tg CO_2 Eq.
* 2007 estimates (EPA 2011b).
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 C. All of the C in cleansers was assumed to be fossil-derived, and, as cleansers eventually biodegrade, all of the C was assumed to be emitted. The first step in estimating C flows was to characterize the "ingredients" in a sample of cleansers. For this analysis, cleansers were limited to the following personal household cleaning products: bar soap, shampoo, laundry detergent (liquid and granular), dishwasher detergent, and dishwashing liquid. Data on the annual consumption of household personal cleansers were obtained from the U.S. Census Bureau 1992, 1997, 2002, and 2007 Economic Census (U.S. Bureau of the Census 1994, 1999, 2004, 2009). Consumption values for 1990 and 1991 were assumed to be the same as the 1992 value; consumption was interpolated between 1992 and 1997, 1997 and 2002, and 2002 and 2007; consumption for 2008 through 2012 was assumed to equal the 2007 value. Cleanser consumption values were adjusted by import and export data to develop US consumption estimates.

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

The Census Bureau presents consumption data in terms of quantity (in units of million gallons or million pounds) and/or terms of value (thousands of dollars) for eight specific categories, such as "household liquid laundry detergents, heavy duty" and "household dry alkaline automatic dishwashing detergents." Additionally, the report provides dollar values for the total consumption of "soaps, detergents, etc.—dry" and "soaps, detergents, etc.—liquid." The categories for which both quantity and value data are available is a subset of total production. Those categories that presented both quantity and value data were used to derive pounds per dollar and gallons per dollar conversion rates, and they were extrapolated (based on the Census Bureau estimate of total value) to estimate the total quantity of dry and liquid[31] cleanser categories, respectively.

Next, the total tonnage of cleansers was calculated (wet and dry combined) for 1997. Multiplying the mean C content (21.9 percent) by this value yielded an estimate of 4.6 Tg CO_2 Eq. in cleansers for 1997. For all subsequent years, it was assumed that the ratio of value of shipments to total carbon content remained constant. For 1998 through 2012, value of shipments was adjusted to 1997 dollars using the producer price index for soap and other detergent manufacturing (Bureau of Labor Statistics 2013). The ratio of value of shipments to carbon content was then applied to arrive at total carbon content of cleansers. For 1992, 2002, and 2007 the estimates are 3.6 Tg CO_2 Eq., 5.1 Tg CO_2 Eq., 7.6 Tg CO_2 Eq., respectively. Estimates for other years are based on these values as described above, and are shown in Table A-76.

Table A-76: C Emitted from Utilization of Soaps, Shampoos, and Detergents (Tg CO_2 Eq.)

	1990	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
C Emissions	3.6	4.2	4.5	4.8	5.1	5.7	6.2	6.7	7.0	7.6	7.1	6.7	6.7	6.5	6.1

Antifreeze and Deicers

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

Annual production data for each glycol compound used as antifreeze and deicers were obtained from the Guide to the Business of Chemistry (ACC 2012). Import and export data were used to adjust annual production data to annual consumption data. The percentage of the annual consumption of each glycol compound used for antifreeze and deicing applications was estimated from Chemical Profiles data published on The Innovation Group website[32] and from similar data published in the Chemical Market Reporter, which became ICIS Chemical Business in 2005.[33] Production data for propylene glycol, diethylene glycol, and triethylene glycol are no longer reported in the Guide to the Business of Chemistry, so data from ICIS Chemical Business on total demand was used with import and export data to estimate production of these chemicals.

The glycol compounds consumed in antifreeze and deicing applications is assumed to be 100 percent emitted as CO_2. Emissions of CO_2 from utilization of antifreeze and deicers are summarized in Table A-77.

Table A-77: C Emitted from Utilization of Antifreeze and Deicers (Tg CO_2 Eq.)

	1990	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
C Emissions	1.2	1.4	1.5	1.3	1.3	1.3	1.4	1.2	1.3	1.2	1.0	0.9	0.8	0.7	0.7

Food Additives

Petrochemical feedstocks are used to manufacture synthetic food additives, including preservatives, flavoring agents, and processing agents. These compounds include glycerin, propylene glycol, benzoic acid, and other compounds. These compounds are incorporated into food products, and are assumed to ultimately enter wastewater treatment plants

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

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

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

where they are degraded by the wastewater treatment processes to CO_2 or to otherwise biodegrade to CO_2. Certain food additives, e.g., glycerin, are manufactured both from petrochemical feedstocks and from biogenic feedstocks. Food additives that are derived from biogenic feedstocks are accounted for in the Land Use, Land-Use Change and Forestry chapter.

Annual production data for food additive compounds were obtained from the Guide to the Business of Chemistry (ACC 2012). Import and export data were used to adjust annual production data to annual consumption data. The percentage of the annual consumption of food additive compounds was estimated from Chemical Profiles data published on The Innovation Group website[34] and from similar data published in the Chemical Market Reporter, which became ICIS Chemical Business in 2005.[35] Production data for several food additive compounds are no longer reported in the Guide to the Business of Chemistry, so data from ICIS Chemical Business on total demand was used with import and export data to estimate production of these chemicals. The consumption of synthetic food additives is assumed to be 100 percent emitted as CO_2. Emissions of CO_2 from utilization of synthetic food additives are summarized in Table A-78.

Table A-78: C Emitted from Utilization of Food Additives (Tg CO_2 Eq.)

	1990	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
C Emissions	0.6	0.7	0.7	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8

Silicones

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

Annual production data for each silicone manufacturing compound were obtained from the Guide to the Business of Chemistry (ACC 2012). Import and export data were used to adjust annual production data to annual consumption data. The percentage of the annual consumption of each silicone manufacturing compound was estimated from Chemical Profiles data published on The Innovation Group website and from similar data published in the Chemical Market Reporter, which became ICIS Chemical Business in 2005[36]. The consumption of silicone manufacturing compounds is assumed to be 100 percent stored, and not emitted as CO_2. Storage of silicone manufacturing compounds is summarized in Table A-79.

Table A-79: C Stored in Silicone Products (Tg CO_2 Eq.)

	1990	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
C Storage	0.3	0.4	0.4	0.4	0.5	0.5	0.5	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5

Uncertainty

A Tier 2 Monte Carlo analysis was performed using @RISK software to determine the level of uncertainty surrounding the estimates of the feedstocks C storage factor and the quantity of C emitted from feedstocks in 2012. The Tier 2 analysis was performed to allow the specification of probability density functions for key variables, within a computational structure that mirrors the calculation of the Inventory estimate. Statistical analyses or expert judgments of uncertainty were not available directly from the information sources for the activity variables; thus, uncertainty estimates were determined using assumptions based on source category knowledge. Uncertainty estimates for production data (the majority of the variables) were assumed to exhibit a normal distribution with a relative error of ±20 percent in the underlying EIA estimates, plus an additional ±15 percent to account for uncertainty in the assignment of imports and exports. An additional 10 percent (for a total of ±45 percent) was applied to the production of other oils (>401 deg. F) to reflect the additional uncertainty in the assignment of part of the production quantity to industrial processes. A relatively narrow uniform distribution ±1 percent to ±15 percent, depending on the fuel type) was applied to each C coefficient.

The Monte Carlo analysis produced a storage factor distribution with a mean of 67 percent, a standard deviation of 4.2 percent, and the 95 percent confidence interval of 56 percent and 72 percent. This compares to the calculated Inventory estimate of 70 percent. The analysis produced a C emission distribution with a mean of 65.4 Tg CO_2 Eq.,

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

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

[36] Ibid.

standard deviation of 15.5 Tg CO_2 Eq., and 95 percent confidence limits of 45.8 and 104.0 Tg CO_2 Eq. This compares with a calculated Inventory estimate of 59.2 Tg CO_2 Eq.

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

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

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

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

Import and export data for petrochemical feedstocks were obtained from EIA, the National Petroleum Refiners Association, and the U.S. BoC for the major categories of petrochemical feedstocks (EIA 2001, NPRA 2001, and U.S. BoC 2006). The complexity of the organic chemical industry, with multiple feedstocks, intermediates, and subtle differences in nomenclature, makes it difficult to ensure that the adjustments to the EIA data for imports and exports is accurate and the approach used here may underestimate or overestimate net exports of C.

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

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

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

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

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

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

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

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

For pesticides, the largest source of uncertainty involves the assumption that an active ingredient’s C is either 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, application method, and harvesting practice. Another smaller source of uncertainty arises from the C content values applied to the unaccounted for portion of active ingredient. C contents vary widely among pesticides, from 7 to 72 percent, and the remaining pesticides may have a chemical make-up that is very different from the 32 pesticides that have been examined. Additionally, pesticide consumption data were only available for 1987, 1993, 1995, 1997, 1999, and 2001 and 2007; the majority of the time series data were interpolated or held constant at the latest (2007) value. Another source of uncertainty is that only the “active” ingredients of pesticides are considered in the calculations; the “inactive” ingredients may also be derived from petrochemical feedstocks.

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

Asphalt and Road Oil

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

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

Methodology and Data Sources

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

The fraction of C emitted by HMA was determined by first calculating the organic emissions (volatile organic compounds [VOCs], carbon monoxide [CO], polycyclic aromatic hydrocarbons [PAHs], hazardous air pollutants [HAPs], and phenol) from HMA paving, using emission factors reported in EPA (2001) and total HMA production.[37] The next step was to estimate the C content of the organic emissions. This calculation was based on the C content of CO and phenol, and an assumption of 85 percent C content for PAHs and HAPs. The C content of asphalt paving is a function of (1) the proportion of asphalt cement in asphalt paving, assumed to be 8 percent asphalt cement content based on EPA (2001), and (2) the proportion of C in asphalt cement. For the latter factor, all paving types were characterized as having a mass fraction of 85 percent C in asphalt cement, based on the assumption that asphalt is primarily composed of saturated paraffinic hydrocarbons. By combining these estimates, the result is that over 99.56 percent of the C in asphalt cement was retained (i.e., stored), and less than 0.44 percent was emitted.

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

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

One caveat associated with this calculation is that it is possible that the carbon flows for asphalt and diluent (volatile petroleum distillate) are accounted for separately in the EIA statistics on fossil fuel flows, and thus the mass

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

balance calculation may need to re-map the system boundaries to correctly account for carbon flows. EPA plans to re-evaluate this calculation in the future.

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

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

Uncertainty

A Tier 2 Monte Carlo analysis was performed using @RISK software to determine the level of uncertainty surrounding the estimates of the asphalt C storage factor and the quantity of C stored in asphalt in 2012. The Tier 2 analysis was performed to allow the specification of probability density functions for key variables, within a computational structure that mirrors the calculation of the Inventory estimate. Statistical analyses or expert judgments of uncertainty were not available directly from the information sources for the activity variables; thus, uncertainty estimates were determined using assumptions based on source category knowledge. Uncertainty estimates for asphalt production were assumed to be ±20 percent, while the asphalt property variables were assumed to have narrower distributions. A narrow uniform distribution, with maximum 5 percent uncertainty (± 5 percent) around the mean, was applied to the C content coefficient.

The Monte Carlo analysis produced a tight distribution of storage factor values, with the 95 percent confidence interval of 99.1 percent and 99.8 percent, with the mean value of 99.6 percent. This compares to the storage factor value used in the Inventory of 99.5 percent. The analysis produced a C emission distribution with a mean of 0.30 Tg CO_2 Eq., standard deviation of 0.13 and 95 percent confidence limits of 0.12 Tg CO_2 Eq. and 0.61 Tg CO_2 Eq. This compares to an Inventory calculated estimate of 0.27 Tg CO_2 Eq.

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

Many of the values used in the analysis are also uncertain and are based on estimates and professional judgment. For example, the asphalt cement input for hot mix asphalt was based on expert advice indicating that the range is variable—from about 3 to 5 percent—with actual content based on climate and geographical factors (Connolly 2000). Over this range, the effect on the calculated C storage factor is minimal (on the order of 0.1 percent). Similarly, changes in the assumed C content of asphalt cement would have only a minor effect.

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

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

Lubricants

Lubricants are used in industrial and transportation applications. They can be subdivided into oils and greases, which differ in terms of physical characteristics (e.g., viscosity), commercial applications, and environmental fate. According to EIA (2013a), the C content from U.S. production of lubricants in 2012 was approximately 5.6 Tg C. Based on apportioning oils and greases to various environmental fates, and characterizing those fates as resulting in either long-term storage or emissions, the overall C storage factor was estimated to be 9.2 percent; thus, emissions in 2012 were about 5.1 Tg C, or 18.6 Tg CO_2 Eq. EIA data were not available for 2012, so it was set equal to the 2011 value.

Methodology and Data Sources

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

Oils

Regulation of used oil in the United States has changed dramatically over the past 20 years.[38] The effect of these regulations and policies has been to restrict landfilling and dumping, and to encourage collection of used oil. The economics of the petroleum industry have generally not favored re-refining—instead, most of the used oil that has been collected has been combusted.

Table A-80 provides an estimated allocation of the fates of lubricant oils (Rinehart 2000), along with an estimate of the proportion of C stored in each fate. The ultimate fate of the majority of oils (about 84 percent) is combustion, either during initial use or after collection as used oil. Combustion results in 99 percent oxidation to CO_2 (EIIP 1999), with correspondingly little long-term storage of C in the form of ash. Dumping onto the ground or into storm sewers, primarily by "do-it-yourselfers" who change their own oil, is another fate that results in conversion to CO_2 given that the releases are generally small and most of the oil is biodegraded (based on the observation that land farming—application to soil—is one of the most frequently used methods for degrading refinery wastes). In the landfill environment, which tends to be anaerobic within municipal landfills, it is assumed that 90 percent of the oil persists in an undegraded form, based on analogy with the persistence of petroleum in native petroleum-bearing strata, which is also anaerobic. Re-refining adds a recycling loop to the fate of oil. Re-refined oil was assumed to have a storage factor equal to the weighted average for the other fates (i.e., after re-refining, the oil would have the same probability of combustion, landfilling, or dumping as virgin oil), that is, it was assumed that about 97 percent of the C in re-refined oil is ultimately oxidized. Because of the dominance of fates that result in eventual release as CO_2, only about 3 percent of the C in oil lubricants goes into long-term storage.

Table A-80: Commercial and Environmental Fate of Oil Lubricants (Percent)

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

* (e.g., in boilers or space heaters)
- Not applicable

Greases

Table A-81 provides analogous estimates for lubricant greases. Unlike oils, grease is generally not combusted during use, and combustion for energy recovery and re-refining is thought to be negligible. Although little is known about the fate of waste grease, it was assumed that 90 percent of the non-combusted portion is landfilled, and the remainder is dumped onto the ground or storm sewers. Because much of the waste grease will be in containers that render it relatively inaccessible to biodegradation, and because greases contain longer chain paraffins, which are more persistent than oils, it was assumed that 90 percent and 50 percent of the C in landfilled and dumped grease, respectively, would be stored. The overall storage factor is 82 percent for grease.

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

Table A-81: Commercial and Environmental Fate of Grease Lubricants (Percent)

Fate of Grease	Portion of Total Grease	C Stored
Combusted During Use	**5%**	**0.1%**
Not Combusted During Use	**95%**	**81.7%**
Landfilled	86%	77.0%
Dumped on the ground or in storm sewers	10%	4.8%
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. These were retrieved from the relevant industry series summaries from the 1997 Economic Census (U.S. Bureau of the Census 1999). Assuming that the mass of lubricants can be allocated according to the proportion of value of production (92 percent oil, 8 percent grease), applying these weights to the storage factors for oils and greases (3 percent and 82 percent) yields an overall storage factor of 9.2 percent.

Uncertainty

A Tier 2 Monte Carlo analysis was performed using @RISK software to determine the level of uncertainty surrounding the estimates of the lubricants weighted average C storage factor and the quantity of C emitted from lubricants in 2012. The Tier 2 analysis was performed to allow the specification of probability density functions for key variables, within a computational structure that mirrors the calculation of the Inventory estimate. Statistical analyses or expert judgments of uncertainty were not available directly from the information sources for the activity variables; thus, uncertainty estimates were determined using assumptions based on source category knowledge. Uncertainty estimates for oil and grease variables were assumed to have a moderate variance, in triangular or uniform distribution. Uncertainty estimates for lubricants production were assumed to be rather high (±20 percent). A narrow uniform distribution, with 6 percent uncertainty (± 6 percent) around the mean, was applied to the lubricant C content coefficient.

The Monte Carlo analysis produced a storage factor distribution with the 95 percent confidence interval of 4 percent and 17 percent around a mean value of 10 percent. This compares to the calculated Inventory estimate of 9 percent. The analysis produced a C emission distribution approximating a normal curve with a mean of 16.9 Tg CO_2 Eq., standard deviation of 1.5 and 95 percent confidence limits of 14.2 Tg CO_2 Eq. and 19.8 Tg CO_2 Eq. This compares to an Inventory calculated estimate of 17.1 Tg CO_2 Eq.

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

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

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

Waxes

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

Methodology and Data Sources

The National Petroleum Refiners Association (NPRA) considers the exact amount of wax consumed each year by end use to be proprietary (Maguire 2004). In general, about thirty percent of the wax consumed each year is used in packaging materials, though this percentage has declined in recent years. The next highest wax end use, and fastest growing end use, is candles, followed by construction materials and firelogs. Table A-82 categorizes some of the wax end uses, which the NPRA generally classifies into cosmetics, plastics, tires and rubber, hot melt (adhesives), chemically modified wax substances, and other miscellaneous wax uses (NPRA 2002).

Table A-82: Emissive and Non-emissive (Storage) Fates of Waxes: Uses by Fate and Percent of Total Mass

Use	Emissive	Non-emissive
Packaging	**6%**	**24%**
Non-packaging	**36%**	**34%**
Candles	18%	2%
Construction Materials	4%	14%
Firelogs	7%	+
Cosmetics	1%	2%
Plastics	1%	2%
Tires/Rubber	1%	1%
Hot Melts	1%	1%
Chemically Modified	0%	1%
Other	2%	9%
Total	**42%**	**58%**

+ Does not exceed 0.5 percent

A C storage factor for each wax end use was estimated and then summed across all end uses to provide an overall C storage factor for wax. Because no specific data on C contents of wax used in each end use were available, all wax products are assumed to have the same C content. Table A-83 categorizes wax end uses identified by the NPRA, and lists each end use's estimated C storage factor.

Table A-83: Wax End-Uses by Fate, Percent of Total Mass, Percent C Stored, and Percent of Total C Mass Stored

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

+ Does not exceed 0.5 percent
Source, mass percentages: NPRA 2002. Estimates of percent stored are based on professional judgment, ICF International.
Note: Totals may not sum due to independent rounding.

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

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

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

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

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

Uncertainty

A Tier 2 Monte Carlo analysis was performed using @RISK software to determine the level of uncertainty surrounding the estimates of the wax C storage factor and the quantity of C emitted from wax in 2011. A Tier 2 analysis was performed to allow the specification of probability density functions for key variables, within a computational structure that mirrors the calculation of the Inventory estimate. Statistical analyses or expert judgments of uncertainty were not available directly from the information sources for the activity variables; thus, uncertainty estimates were determined using assumptions based on source category knowledge. Uncertainty estimates for wax variables were assumed to have a moderate variance, in normal, uniform, or triangular distribution; uniform distributions were applied to total consumption of waxes and the C content coefficients.

The Monte Carlo analysis produced a storage factor distribution, whose 95 percent confidence interval values fell within the range of 49 percent and 71 percent, around the mean value of about 60 percent. This compares to the calculated Inventory estimate of 58 percent. The analysis produced an emission distribution, with the 95 percent confidence interval values of 0.3 Tg CO_2 Eq. and 0.8 Tg CO_2 Eq., with a mean value of 0.5 Tg CO_2 Eq. This compares with a calculated Inventory estimate of 0.5 Tg CO_2 Eq., which falls within the range of 95 percent confidence limits established by this quantitative uncertainty analysis. Uncertainty associated with the wax storage factor is considerable due to several assumptions pertaining to wax imports/exports, consumption, and fates.

Miscellaneous Products

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

Methodology and Data Sources

Data are not available concerning the distribution of each of the above-listed subcategories within the "miscellaneous products" category. However, based on the anticipated disposition of the products in each subcategory, it is assumed that all of the C content of miscellaneous products is emitted rather than stored. Petrolatum and specialty oils (which include greases) are likely to end up in solid waste or wastewater streams rather than in durable products, and would be emitted through waste treatment. Absorption oil is used in natural gas processing and is not a feedstock for manufacture of durable products Jet fuel and rocket fuel are assumed to be combusted in use, and synthetic natural gas feedstocks are assumed to be converted to synthetic natural gas that is also combusted in use. Lube refining by-products could potentially be used as feedstocks for manufacture of durable goods, but such by-products are more likely to be used in emissive uses. Lube refining by-products and absorption oils are liquids and are precluded from disposal in landfills. Because no sequestering end uses of any of the miscellaneous products subcategories have been identified, a zero percent storage factor is assigned to miscellaneous products. According to EIA (2013a), the C content of miscellaneous petroleum products in 2012 was approximately 20.3 Tg C/QBtu. EIA data were not available for 2012, so it was set equal to the 2011 value. One hundred percent of the C content is assumed to be emitted to the atmosphere, where it is oxidized to CO_2.

Uncertainty

A separate uncertainty analysis was not conducted for miscellaneous products, though this category was included in the uncertainty analysis of other non-energy uses discussed in the following section.

Other Non-Energy Uses

The remaining fuel types use storage factors that are not based on U.S.-specific analysis. For industrial coking coal and distillate fuel oil, storage factors were taken from IPCC (2006), which in turn draws from Marland and Rotty (1984). These factors are 0.1 and 0.5, respectively.

IPCC does not provide guidance on storage factors for the remaining fuel types (petroleum coke, miscellaneous products, and other petroleum), and assumptions were made based on the potential fate of C in the respective NEUs. Specifically, the storage factor for petroleum coke is 0.3, based on information from Huurman (2006) indicating that petroleum coke is used in the Netherlands for production of pigments, with 30% being stored long-term. EIA (2013a) defines "miscellaneous products" as "all finished products not classified elsewhere (e.g., petrolatum, lube refining by-products (aromatic extracts and tars), absorption oils, ram-jet fuel, petroleum rocket fuels, synthetic natural gas feedstocks, and specialty oils)." All of these uses are emissive, and therefore the storage factor for miscellaneous products is set at zero. The "other petroleum" category is reported by U.S. territories and accounts mostly for the same products as miscellaneous products, but probably also includes some asphalt, known to be non-emissive. The exact amount of asphalt or any of the other miscellaneous products is confidential business information, but based on judgment the storage factor for this category was estimated at 0.1.

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

Uncertainty

A Tier 2 Monte Carlo analysis was performed using @RISK software to determine the level of uncertainty surrounding the weighted average of the remaining fuels' C storage factors and the total quantity of C emitted from these other fuels in 2012. A Tier 2 analysis was performed to allow the specification of probability density functions for key variables, within a computational structure that mirrors the calculation of the Inventory estimate. Statistical analyses or expert judgments of uncertainty were not available directly from the information sources for some of the activity variables; thus, uncertainty estimates were determined using assumptions based on source category knowledge. A uniform distribution was applied to coking coal consumption, while the remaining consumption inputs were assumed to be normally distributed. The C content coefficients were assumed to have a uniform distribution; the greatest uncertainty range of 10 percent (±10%) around the inventory value, was applied to coking coal and miscellaneous products. C coefficients for distillate fuel oil ranged from 18.5 to 21.1 Tg C/QBtu. The fuel-specific storage factors were assigned wide triangular distributions indicating greater uncertainty.

The Monte Carlo analysis produced a storage factor distribution with 95 percent confidence limits of 8 percent and 47 percent, with a mean of 25 percent. This compares to the Inventory calculation of weighted average (across the various fuels) storage factor of about 8 percent. The analysis produced an emission distribution, with the 95 percent confidence limit of 18.8 Tg CO_2 Eq. and 35.0 Tg CO_2 Eq., and a mean of 27.2 Tg CO_2 Eq. This compares with the Inventory estimate of 33.3 Tg CO_2 Eq., which falls closer to the upper boundary of the 95 percent confidence limit. The uncertainty analysis results are driven primarily by the very broad uncertainty inputs for the storage factors.

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ANNEX 3 Methodological Descriptions for Additional Source or Sink Categories

3.1. Methodology for Estimating Emissions of CH_4, N_2O, and Indirect Greenhouse Gases from Stationary Combustion

Estimates of CH_4 and N_2O Emissions

Energy consumption from stationary combustion activities was grouped by sector: industrial, commercial, residential, electric power, and U.S. territories. For CH_4 and N_2O from industrial, commercial, residential, and U.S. territories, estimates were based upon consumption of coal, gas, oil, and wood. Energy consumption and wood consumption data for the United States were obtained from EIA's *Monthly Energy Review, February 2014* and Published Supplemental Tables on Petroleum Product detail (EIA 2014). Because the United States does not include territories in its national energy statistics, fuel consumption data for territories were collected separately from the EIA's International Energy Statistics (EIA 2013a).[39] Fuel consumption for the industrial sector was adjusted to subtract out construction and agricultural use, which is reported under mobile sources.[40] Construction and agricultural fuel use was obtained from EPA (2011). The energy consumption data by sector were then 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 A-84 provides annual energy consumption data for the years 1990 through 2012.

In this inventory, the emission estimation methodology for the electric power sector was revised from Tier 1 to Tier 2 as fuel consumption by technology-type for the electricity generation sector was obtained from the Acid Rain Program Dataset (EPA 2013). This combustion technology-and fuel-use data was available by facility from 1996 to 2012. Since there was a difference between the EPA (2013) and EIA (2014) total energy consumption estimates, the remainder between total energy consumption using EPA (2013) and EIA (2014) was apportioned to each combustion technology type and fuel combination using a ratio of energy consumption by technology type from 1996 to 2012.

Energy consumption estimates were not available from 1990 to 1995 in the EPA (2013) dataset, and as a result, consumption was calculated using total electric power consumption from EIA (2014) and the ratio of combustion technology and fuel types from EPA 2013. The consumption estimates from 1990 to 1995 were estimated by applying the 1996 consumption ratio by combustion technology type to the total EIA consumption for each year from 1990 to 1995.

Lastly, there were significant differences between wood biomass consumption in the electric power sector between the EPA (2013) and EIA (2014) datasets. The difference in wood biomass consumption in the electric power sector was distributed to the residential, commercial, and industrial sectors according to their percent share of wood biomass energy consumption calculated from EIA (2014).

Step 2: Determine the Amount of CH_4 and N_2O Emitted

Activity data for industrial, commercial, residential, and U.S. territories and fuel type for each of these sectors were then multiplied by default Tier 1 emission factors to obtain emission estimates. Emission factors for the residential, commercial, and industrial sectors were taken from the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC 2006). These N_2O emission factors by fuel type (consistent across sectors) were also assumed for U.S. territories. The CH_4 emission factors by fuel type for U.S. territories were estimated based on the emission factor for the primary sector in which each fuel was combusted. Table A-85 provides emission factors used for each sector and fuel type. For the electric power sector, emissions were estimated by multiplying fossil fuel and wood consumption by technology- and fuel-specific Tier 2 IPCC emission factors shown in Table A-86. Emission factors were used from the 2006 IPCC Guidelines as the factors presented in this IPCC guidance were taken directly from U.S. EPA publications on emissions rates for combustion sources.

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[39] U.S. territories data also include combustion from mobile activities because data to allocate territories' energy use were unavailable. For this reason, CH_4 and N_2O emissions from combustion by U.S. Territories are only included in the stationary combustion totals.

[40] Though emissions from construction and farm use occur due to both stationary and mobile sources, detailed data was not available to determine the magnitude from each. Currently, these emissions are assumed to be predominantly from mobile sources.

Estimates of NOx, CO, and NMVOC Emissions

Emissions estimates for NO_x, CO, and NMVOCs were obtained from data published on the National Emission Inventory (NEI) Air Pollutant Emission Trends web site (EPA 2013a, b, EPA 2009), and disaggregated based on EPA (2003). .

For indirect greenhouse gases, the major source categories included 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 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. 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.

The basic calculation procedure for most source categories presented in EPA (2003) and EPA (2009) 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 A-84: Fuel Consumption by Stationary Combustion for Calculating CH_4 and N_2O Emissions (TBtu)

Fuel/End-Use Sector	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Coal	**19,610**	**20,888**	**21,328**	**21,879**	**22,224**	**22,159**	**23,080**	**22,391**	**22,343**	**22,576**	**22,636**	**22,949**	**22,458**	**22,710**	**22,225**	**19,670**	**20,697**	**18,989**	**6,525**
Residential	31	17	17	16	12	14	11	12	12	12	11	8	6	8	NE	NE	NE	NE	NE
Commercial	124	117	122	129	93	103	92	97	90	82	103	97	65	70	81	73	70	62	44
Industrial	1,640	1,527	1,455	1,458	1,471	1,373	1,349	1,358	1,244	1,249	1,262	1,219	1,189	1,131	1,081	877	952	866	785
Electric Power	17,807	19,217	19,724	20,266	20,637	20,659	21,618	20,920	20,987	21,199	21,228	21,591	21,161	21,465	21,026	18,682	19,639	18,024	5,659
U.S. Territories	7	10	10	10	11	10	10	4	11	34	32	33	37	37	37	37	37	37	37
Petroleum	**6,226**	**5,652**	**6,150**	**6,194**	**5,885**	**6,205**	**6,160**	**6,638**	**6,016**	**6,399**	**6,586**	**6,504**	**6,212**	**6,079**	**5,268**	**4,692**	**4,865**	**4,454**	**6,611**
Residential	1,375	1,261	1,397	1,334	1,207	1,342	1,427	1,463	1,359	1,466	1,475	1,369	1,205	1,225	1,183	1,139	1,119	1,032	950
Commercial	891	694	718	655	609	614	694	719	645	762	767	716	678	681	650	675	651	635	517
Industrial	2,788	2,375	2,718	2,660	2,220	2,328	2,298	2,545	2,381	2,505	2,684	2,792	3,118	3,004	2,456	1,959	2,068	1,907	1,795
Electric Power	797	860	883	1,100	1,403	1,459	1,269	1,279	1,074	1,043	1,007	1,004	590	618	488	383	412	266	2,736
U.S. Territories	375	462	435	445	445	461	472	632	557	622	654	623	621	552	492	536	614	614	614
Natural Gas	**17,266**	**19,337**	**20,233**	**20,131**	**19,840**	**19,778**	**20,919**	**20,224**	**20,908**	**20,894**	**21,152**	**20,938**	**20,626**	**22,019**	**22,286**	**21,952**	**22,913**	**23,115**	**31,423**
Residential	4,491	4,954	5,354	5,093	4,646	4,835	5,105	4,889	4,995	5,209	4,981	4,946	4,476	4,835	5,010	4,883	4,878	4,805	4,242
Commercial	2,682	3,096	3,226	3,285	3,083	3,115	3,252	3,097	3,212	3,261	3,201	3,073	2,902	3,085	3,228	3,187	3,165	3,216	2,960
Industrial	7,716	8,723	9,020	9,033	8,826	8,425	8,656	7,949	8,086	7,845	7,914	7,330	7,323	7,521	7,571	7,125	7,683	7,783	8,201
Electric Power	2,376	2,564	2,632	2,720	3,285	3,403	3,894	4,266	4,591	4,551	5,032	5,565	5,899	6,550	6,447	6,730	7,159	7,194	15,994
U.S. Territories	NE	NE	NE	NE	NE	NE	13	23	23	27	25	24	26	27	29	27	28	27	27
Wood	**2,216**	**2,370**	**2,437**	**2,371**	**2,184**	**2,214**	**2,262**	**2,006**	**1,995**	**2,002**	**2,121**	**2,137**	**2,099**	**2,089**	**2,059**	**1,931**	**1,981**	**2,010**	**2,001**
Residential	614	547	571	455	404	414	444	393	409	434	442	468	413	456	508	545	482	489	417
Commercial	70	76	80	78	68	71	76	71	74	78	76	76	71	76	79	79	78	75	62
Industrial	1,526	1,739	1,779	1,831	1,704	1,720	1,731	1,533	1,503	1,480	1,592	1,581	1,599	1,534	1,446	1,284	1,395	1,422	1,318
Electric Power	7	8	8	8	8	9	11	9	9	10	11	11	17	23	27	23	25	24	204
U.S. Territories	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE

NE (Not Estimated)

Note: Totals may not sum due to independent rounding.

Table A-85: CH_4 and N_2O Emission Factors by Fuel Type and Sector (g/GJ)[41]

Fuel/End-Use Sector	CH_4	N_2O
Coal		
Residential	300	1.5
Commercial	10	1.5
Industrial	10	1.5
Electric Power	1	1.5
U.S. Territories	1	1.5
Petroleum		
Residential	10	0.6
Commercial	10	0.6
Industrial	3	0.6
Electric Power	3	0.6
U.S. Territories	5	0.6
Natural Gas		
Residential	5	0.1
Commercial	5	0.1
Industrial	1	0.1
Electric Power	1	0.1
U.S. Territories	1	0.1
Wood		
Residential	300	4.0
Commercial	300	4.0
Industrial	30	4.0
Electric Power	30	4.0
U.S. Territories	NA	NA

NA (Not Applicable)

Table A-86: CH_4 and N_2O Emission Factors by Technology Type and Fuel Type for the Electric Power Sector(g/GJ)[42]

Technology	Configuration	CH_4	N_2O
Liquid Fuels			
Residual Fuel Oil/Shale Oil Boilers	Normal Firing	0.8	0.3
	Tangential Firing	0.8	0.3
Gas/Diesel Oil Boilers	Normal Firing	0.9	0.4
	Tangential Firing	0.9	0.4
Large Diesel Oil Engines >600 hp (447kW)		4	NA
Solid Fuels			
Pulverized Bituminous Combination Boilers	Dry Bottom, wall fired	0.7	0.5
	Dry Bottom, tangentially fired	0.7	1.4
	Wet bottom	0.9	1.4
Bituminous Spreader Stoker Boilers	With and without re-injection	1	0.7
Bituminous Fluidized Bed Combustor	Circulating Bed	1	61
	Bubbling Bed	1	61
Bituminous Cyclone Furnace		0.2	0.6
Lignite Atmospheric Fluidized Bed		NA	71
Natural Gas			
Boilers		1	1
Gas-Fired Gas Turbines >3MW		4	1
Large Duel-Fuel Engines		258	NA
Combined Cycle		1	3
Peat			
Peat Fluidized Bed Combustion	Circulating Bed	3	7
	Bubbling Bed	3	3
Biomass			
Wood/Wood Waste Boilers		11	7
Wood Recovery Boilers		1	1

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[41] GJ (Gigajoule) = 10^9 joules. One joule = 9.486×10^{-4} Btu

[42] GJ (Gigajoule) = 10^9 joules. One joule = 9.486×10^{-4} Btu

Table A-87: NO$_x$ Emissions from Stationary Combustion (Gg)

Sector/Fuel Type	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Electric Power	**6,045**	**5,792**	**5,581**	**5,683**	**5,638**	**5,183**	**4,829**	**4,454**	**4,265**	**3,929**	**3,594**	**3,434**	**3,213**	**2,993**	**2,772**	**2,451**	**2,129**	**1,807**	**1,557**
Coal	5,119	5,061	5,079	5,118	4,932	4,437	4,130	3,802	3,634	3,348	3,062	2,926	2,738	2,550	2,362	2,088	1,814	1,540	1,327
Fuel Oil	200	87	107	131	202	179	147	149	142	131	120	114	107	100	92	82	71	60	52
Natural gas	513	510	248	277	329	393	376	325	310	286	261	250	234	218	202	178	155	131	113
Wood	NA	NA	5	6	24	33	36	37	36	33	30	29	27	25	23	21	18	15	13
Other Fuels[a]	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Internal Combustion	213	134	142	150	149	141	140	140	143	132	121	115	108	100	93	82	71	61	52
Industrial	**2,559**	**2,650**	**2,667**	**2,613**	**2,570**	**2,283**	**2,278**	**2,296**	**1,699**	**1,636**	**1,573**	**1,506**	**1,390**	**1,274**	**1,158**	**1,131**	**1,105**	**1,078**	**1,078**
Coal	530	541	490	487	475	475	484	518	384	369	355	340	314	288	261	255	249	243	243
Fuel Oil	240	224	203	196	190	190	166	153	114	109	105	101	93	85	77	76	74	72	72
Natural gas	877	999	900	880	869	706	710	711	526	506	487	466	430	394	359	350	342	334	334
Wood	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other Fuels[a]	119	111	109	103	104	100	109	116	86	82	79	76	70	64	58	57	56	54	54
Internal Combustion	792	774	965	948	932	813	809	798	591	568	546	523	483	443	403	393	384	375	375
Commercial	**671**	**607**	**734**	**538**	**510**	**483**	**507**	**428**	**438**	**455**	**473**	**490**	**471**	**452**	**433**	**453**	**472**	**582**	**582**
Coal	36	35	30	32	34	23	21	21	19	19	19	19	18	17	15	15	15	15	15
Fuel Oil	88	94	86	88	73	54	52	52	50	49	49	49	46	42	39	39	38	38	38
Natural gas	181	210	224	229	220	156	161	165	157	156	156	155	145	134	124	122	121	119	119
Wood	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other Fuels[a]	366	269	394	190	184	249	273	189	212	230	249	267	263	258	254	276	299	410	410
Residential	**749**	**813**	**726**	**699**	**651**	**441**	**439**	**446**	**422**	**421**	**419**	**417**	**390**	**362**	**335**	**330**	**325**	**321**	**321**
Coal[b]	NA	NA	NA	NA	NA	NA	NA	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	NA	NA	NA	NA	NA	NA	NA
Natural Gas[b]	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Wood	42	44	27	27	27	25	21	22	21	21	21	20	19	18	16	16	16	16	16
Other Fuels[a]	707	769	699	671	624	416	417	424	402	400	399	397	371	345	318	314	309	305	305
Total	**10,023**	**9,862**	**9,708**	**9,534**	**9,369**	**8,390**	**8,053**	**7,623**	**6,825**	**6,442**	**6,059**	**5,847**	**5,464**	**5,081**	**4,698**	**4,365**	**4,031**	**3,787**	**3,538**

NA (Not Applicable)

[a] "Other Fuels" include LPG, waste oil, coke oven gas, coke, and non-residential wood (EPA 2003, 2009, 2010b, 2013).

[b] Residential coal, fuel oil, and natural gas emissions are included in the "Other Fuels" category (EPA 2003, 2009, 2010b, 2013).

Note: Totals may not sum due to independent rounding.

Table A-88: CO Emissions from Stationary Combustion (Gg)

Sector/Fuel Type	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Electric Power	**329**	**337**	**369**	**384**	**410**	**450**	**439**	**439**	**594**	**590**	**586**	**581**	**606**	**631**	**655**	**670**	**685**	**700**	**700**
Coal	213	227	228	233	220	187	221	220	298	296	293	291	304	316	328	336	343	351	351
Fuel Oil	18	9	11	13	17	36	27	28	38	37	37	37	38	40	41	42	43	44	44
Natural gas	46	49	72	76	88	151	96	92	125	124	123	122	127	132	137	141	144	147	147
Wood	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other Fuels[a]	NA	NA	7	8	30	24	31	32	44	43	43	43	44	46	48	49	50	51	51
Internal Combustion	52	52	52	54	55	52	63	67	91	90	89	89	93	96	100	102	105	107	107
Industrial	**797**	**958**	**1,078**	**1,055**	**1,044**	**1,100**	**1,106**	**1,137**	**1,150**	**1,114**	**1,079**	**1,042**	**965**	**888**	**811**	**820**	**829**	**839**	**839**
Coal	95	88	100	99	96	114	118	125	127	123	119	115	106	98	89	90	91	92	92

Fuel Oil	67	64	49	47	46	54	48	45	46	44	43	41	38	35	32	33	33	33	33
Natural gas	205	313	307	307	305	350	355	366	370	359	347	335	311	286	261	264	267	270	270
Wood	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other Fuels[a]	253	270	316	302	303	286	300	321	325	315	305	295	273	251	229	232	235	237	237
Internal Combustion	177	222	305	299	294	296	285	279	282	274	265	256	237	218	199	201	204	206	206
Commercial	**205**	**211**	**122**	**126**	**122**	**151**	**151**	**154**	**177**	**173**	**169**	**166**	**156**	**146**	**137**	**140**	**142**	**145**	**145**
Coal	13	14	13	13	14	16	14	13	15	15	15	14	14	13	12	12	12	13	13
Fuel Oil	16	17	17	18	15	17	17	17	20	19	19	19	18	16	15	16	16	16	16
Natural gas	40	49	58	59	57	81	83	84	97	95	93	91	86	80	75	77	78	80	80
Wood	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other Fuels[a]	136	132	34	36	36	36	36	38	44	43	42	41	39	37	34	35	36	36	36
Residential	**3,668**	**3,877**	**2,364**	**2,362**	**2,353**	**3,323**	**2,644**	**2,648**	**3,044**	**2,981**	**2,919**	**2,855**	**2,689**	**2,523**	**2,356**	**2,406**	**2,455**	**2,504**	**2,504**
Coal[b]	NA	NA	NA	NA	NA	NA	NA	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	NA	NA	NA	NA	NA	NA	NA
Natural Gas[b]	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Wood	3,430	3,629	2,132	2,133	2,133	3,094	2,416	2,424	2,787	2,730	2,672	2,614	2,462	2,310	2,157	2,202	2,248	2,293	2,293
Other Fuels[a]	238	248	231	229	220	229	228	224	257	252	246	241	227	213	199	203	207	211	211
Total	**5,000**	**5,383**	**3,933**	**3,927**	**3,928**	**5,024**	**4,340**	**4,377**	**4,965**	**4,859**	**4,752**	**4,644**	**4,416**	**4,188**	**3,959**	**4,036**	**4,112**	**4,188**	**4,188**

NA (Not Applicable)

[a] "Other Fuels" include LPG, waste oil, coke oven gas, coke, and non-residential wood (EPA 2003, 2009, 2010b).

[b] Residential coal, fuel oil, and natural gas emissions are included in the "Other Fuels" category (EPA 2003, 2009, 2010b).

Note: Totals may not sum due to independent rounding.

Table A-89: NMVOC Emissions from Stationary Combustion (Gg)

Sector/Fuel Type	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Electric Power	**43**	**40**	**44**	**47**	**51**	**49**	**56**	**55**	**45**	**44**	**44**	**44**	**42**	**41**	**39**	**38**	**37**	**36**	**36**
Coal	24	26	25	26	26	25	27	26	21	21	21	21	20	19	19	18	18	17	17
Fuel Oil	5	2	3	4	5	4	4	4	4	4	3	3	3	3	3	3	3	3	3
Natural gas	2	2	7	7	9	9	12	12	10	10	10	10	9	9	9	8	8	8	8
Wood	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other Fuels[a]	NA	NA	+	+	1	2	2	2	1	1	1	1	1	1	1	1	1	1	1
Internal Combustion	11	9	9	10	10	10	11	10	9	8	8	8	8	8	7	7	7	7	7
Industrial	**165**	**187**	**163**	**160**	**159**	**156**	**157**	**159**	**138**	**132**	**126**	**120**	**112**	**104**	**97**	**97**	**98**	**98**	**98**
Coal	7	5	6	6	6	9	9	10	9	9	8	8	7	7	6	6	6	6	6
Fuel Oil	11	11	8	7	7	10	9	9	7	7	7	6	6	6	5	5	5	5	5
Natural gas	52	66	54	54	53	52	53	54	47	45	43	41	38	35	33	33	33	33	33
Wood	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other Fuels[a]	46	45	33	31	31	26	27	29	25	24	23	22	21	19	18	18	18	18	18
Internal Combustion	49	60	63	62	61	60	58	57	49	47	45	43	40	37	35	35	35	35	35
Commercial	**18**	**21**	**22**	**22**	**21**	**25**	**28**	**29**	**61**	**53**	**45**	**33**	**34**	**35**	**36**	**38**	**40**	**45**	**45**
Coal	1	1	1	1	1	1	1	1	1	1	1	1	1	+	+	+	+	+	+
Fuel Oil	3	3	3	3	3	3	4	4	6	5	3	2	2	2	2	2	2	2	2
Natural gas	7	10	13	13	12	11	14	14	23	18	14	9	8	7	6	7	7	7	7
Wood	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other Fuels[a]	8	8	5	5	5	10	9	10	31	29	27	22	24	26	28	30	31	35	35

Residential	**686**		**725**	**789**	**788**	**786**	**815**	**837**	**836**	**1,341**	**1,067**	**792**	**518**	**465**	**411**	**357**	**379**	**401**	**423**	**423**
Coal[b]	NA		NA	NA	NA	NA	NA	NA	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	NA	NA	NA	NA	NA	NA	NA
Natural Gas[b]	NA		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Wood	651		688	756	756	756	794	809	809	1,297	1,032	767	501	450	398	346	367	388	409	409
Other Fuels[a]	35		37	33	32	30	21	27	27	43	35	26	17	15	13	12	12	13	14	14
Total	**912**		**973**	**1,018**	**1,017**	**1,017**	**1,045**	**1,077**	**1,080**	**1,585**	**1,296**	**1,008**	**715**	**653**	**591**	**530**	**553**	**576**	**602**	**602**

NA (Not Applicable)

+ Does not exceed 1 Gg.

[a] "Other Fuels" include LPG, waste oil, coke oven gas, coke, and non-residential wood (EPA 2003, 2009, 2010b).

[b] Residential coal, fuel oil, and natural gas emissions are included in the "Other Fuels" category (EPA 2003, 2009, 2010b).

Note: Totals may not sum due to independent rounding.

3.2. Methodology for Estimating Emissions of CH_4, N_2O, and Indirect Greenhouse Gases from Mobile Combustion and Methodology for and Supplemental Information on Transportation-Related GHG Emissions

Estimating CO_2 Emissions by Transportation Mode

Transportation-related CO_2 emissions, as presented in the Carbon Dioxide Emissions from Fossil Fuel Combustion section of the Energy chapter, were calculated using the methodology described in Annex 2.1. This section provides additional information on the data sources and approach used for each transportation fuel type. As noted in Annex 2.1, CO_2 emissions estimates for the transportation sector were calculated directly for on-road diesel fuel and motor gasoline based on data sources for individual modes of transportation (considered a "bottom up" approach). For most other fuel and energy types (aviation gasoline, residual fuel oil, natural gas, LPG, and electricity), CO_2 emissions were calculated based on transportation sector-wide fuel consumption estimates from the Energy Information Administration (EIA 2014 and EIA 2013a) and apportioned to individual modes (considered a "top down" approach). CO_2 emissions from commercial jet fuel use are obtained directly from the Federal Aviation Administration (FAA 2014), while CO_2 emissions from other aircraft jet fuel consumption is determined using a top down approach.

Based on interagency discussions between EPA, EIA, and FHWA beginning in 2005, it was agreed that use of "bottom up" data would be more accurate for diesel fuel and motor gasoline, based on the availability of reliable transportation-specific data sources. A "bottom up" diesel calculation was first implemented in the 1990-2005 Inventory, and a bottom-up gasoline calculation was introduced in the 1990-2006 Inventory for the calculation of emissions from on-road vehicles. Estimated motor gasoline and diesel consumption data for on-road vehicles by vehicle type come from FHWA's *Highway Statistics*, Table VM-1 (FHWA 1996 through 2014)[43], and are based on federal and state fuel tax records. These fuel consumption estimates were then combined with estimates of fuel shares by vehicle type from DOE's Transportation Energy Data Book (DOE 1993 through 2013) to develop an estimate of fuel consumption for each vehicle type (i.e., passenger cars, light-duty trucks, buses, medium- and heavy-duty trucks, motorcycles). The on-road gas and diesel fuel consumption estimates by vehicle type were then adjusted for each year so that the sum of gasoline and diesel fuel consumption across all vehicle categories matched the fuel consumption estimates in *Highway Statistics'* Tables MF-21 and MF-27 (FHWA 1996 through 2014). Table MF-21 provided fuel consumption estimates for the most current Inventory year; Table MF-27 provided fuel consumption estimates for years 1990-2011. This resulted in a final estimate of motor gasoline and diesel fuel use by vehicle type, consistent with the FHWA total for on-road motor gasoline and diesel fuel use.

Estimates of diesel fuel consumption from rail were taken from the Association of American Railroads (AAR 2008 through 2013) for Class I railroads, the American Public Transportation Association (APTA 2007 through 2013 and APTA 2006) and Gaffney (2007) for commuter rail, the Upper Great Plains Transportation Institute (Benson 2002 through 2004) and Whorton (2006 through 2012) for Class II and III railroads, and DOE's *Transportation Energy Data Book* (DOE 1993 through 2013) for passenger rail. Estimates of diesel from ships and boats were taken from EIA's *Fuel Oil and Kerosene Sales* (1991 through 2013).

Since EIA's total fuel consumption estimate for each fuel type is considered to be accurate at the national level, adjustments needed to be made in the estimates for other sectors to equal the EIA total. In the case of motor gasoline, estimates of fuel use by recreational boats come from EPA's NONROAD Model (EPA 2013b), and these estimates along with those from other sectors (e.g., commercial sector, industrial sector) were adjusted. Similarly, to ensure consistency with EIA's total diesel estimate for all sectors, the diesel consumption totals for the residential, commercial, and industrial sectors were adjusted downward proportionately.

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[43] In 2011 FHWA changed its methods for estimating vehicle miles traveled (VMT) and related data. These methodological changes included how vehicles are classified, moving from a system based on body-type to one that is based on wheelbase. These changes were first incorporated for the 2010 Inventory and apply to the 2007-12 time period. This resulted in large changes in VMT and fuel consumption data by vehicle class, thus leading to a shift in emissions among on-road vehicle classes. For example, the category "Passenger Cars" has been replaced by "Light-duty Vehicles-Short Wheelbase" and "Other 2 axle-4 Tire Vehicles" has been replaced by "Light-duty Vehicles, Long Wheelbase." This change in vehicle classification has moved some smaller trucks and sport utility vehicles from the light truck category to the passenger vehicle category in this emission inventory. These changes are reflected in a large drop in light-truck emissions between 2006 and 2007.

As noted above, for fuels other than motor gasoline and diesel, EIA's transportation sector total was apportioned to specific transportation sources. For jet fuel, estimates come from: FAA (2014) for domestic and international commercial aircraft, and DESC (2013) for domestic and international military aircraft. General aviation jet fuel consumption is calculated as the difference between total jet fuel consumption as reported by EIA and the total consumption from commercial and military jet fuel consumption. Commercial jet fuel CO_2 estimates are obtained directly from the Federal Aviation Administration (FAA 2014), while CO_2 emissions from domestic military and general aviation jet fuel consumption is determined using a top down approach. Domestic commercial jet fuels CO_2 from FAA is subtracted from total domestic jet fuel CO_2 emissions, and this remaining value is apportioned among domestic military and domestic general aviation based on their relative proportion of energy consumption. Estimates for biofuels, including ethanol and biodiesel were discussed separately in Chapter 3.2 under the methodology for Estimating CO2 from Fossil Combustion, and in Chapter 3.10 Wood Biomass and Ethanol Consumption and were not apportioned to specific transportation sources. Consumption estimates for biofuels were calculated based on data from the Energy Information Administration (EIA 2014).

Table A-90 displays estimated fuel consumption by fuel and vehicle type. Table A-91 displays estimated energy consumption by fuel and vehicle type. The values in both of these tables correspond to the figures used to calculate CO_2 emissions from transportation. Except as noted above, they are estimated based on EIA transportation sector energy estimates by fuel type, with activity data used to apportion consumption to the various modes of transport. For motor gasoline, the figures do not include ethanol blended with gasoline; although ethanol is included in FHWA's totals for reported motor gasoline use. Ethanol is a biofuel and in order for consistency with IPCC methodological guidance and UNFCCC reporting obligations, net carbon fluxes in biogenic carbon reservoirs in croplands are accounted for in the estimates for Land Use, Land-Use Change and Forestry chapter, not in Energy chapter totals. Ethanol and biodiesel consumption estimates are shown separately in Table A-92.

Table A-90. Fuel Consumption by Fuel and Vehicle Type (million gallons unless otherwise specified)

Fuel/Vehicle Type	1990	1995	2000	2001	2002	2003	2004	2005	2006	2007[a]	2008	2009	2010	2011	2012
Motor Gasoline[b]	**110,441**	**118,217**	**129,102**	**130,582**	**133,257**	**133,900**	**135,708**	**134,659**	**132,947**	**132,546**	**127,528**	**127,322**	**126,922**	**124,430**	**124,081**
Passenger Cars	69,763	67,948	72,860	73,466	74,911	72,623	72,223	74,600	71,647	89,795	86,376	86,019	85,745	85,301	85,241
Light-Duty Trucks	34,698	44,369	50,774	51,251	52,442	55,951	58,118	54,274	55,460	35,401	33,723	34,311	34,267	32,638	32,325
Motorcycles	194	200	210	194	191	185	195	184	212	478	496	479	424	414	473
Buses	39	42	44	40	38	36	50	41	42	81	86	89	87	85	91
Medium- and Heavy-Duty Trucks	4,350	4,072	4,096	3,990	4,038	3,479	3,510	3,962	4,008	5,233	5,322	4,918	4,918	4,525	4,493
Recreational Boats[c]	1,397	1,585	1,119	1,641	1,637	1,626	1,612	1,599	1,577	1,557	1,524	1,506	1,481	1,468	1,459
Distillate Fuel Oil (Diesel Fuel)	**25,631**	**31,605**	**39,241**	**39,058**	**40,348**	**41,177**	**42,668**	**44,659**	**45,848**	**46,432**	**44,032**	**39,940**	**41,571**	**42,536**	**42,445**
Passenger Cars	771	765	356	357	364	412	419	414	403	402	362	354	368	401	405
Light-Duty Trucks	1,119	1,452	1,961	2,029	2,133	2,652	2,822	2,518	2,610	1,326	1,182	1,181	1,228	1,283	1,284
Buses	781	851	997	906	860	930	1,316	1,030	1,049	1,547	1,477	1,374	1,370	1,479	1,585
Medium- and Heavy-Duty Trucks	18,574	23,241	30,180	30,125	31,418	31,540	32,599	35,160	36,079	37,496	35,692	32,384	33,719	34,015	34,140
Recreational Boats	190	228	266	274	282	289	297	305	313	321	329	337	345	353	361
Ships and Other Boats	735	1,204	1,377	1,248	1,202	1,178	807	785	729	800	773	775	733	1,005	746
Rail	3,461	3,864	4,106	4,119	4,089	4,176	4,407	4,446	4,665	4,539	4,216	3,535	3,807	3,999	3,923
Jet Fuel[d]	**19,186**	**17,991**	**20,002**	**19,454**	**19,004**	**18,389**	**19,147**	**19,420**	**18,695**	**18,407**	**17,749**	**15,809**	**15,537**	**15,036**	**14,705**
Commercial Aircraft	11,569	12,136	14,672	13,121	12,774	12,943	13,147	13,976	14,426	14,708	13,400	12,588	11,931	12,067	11,932
General Aviation Aircraft	4,034	3,361	3,163	3,975	4,119	3,323	3,815	3,583	2,590	2,043	2,682	1,787	2,322	1,895	1,659
Military Aircraft	3,583	2,495	2,167	2,359	2,110	2,123	2,185	1,860	1,679	1,656	1,667	1,434	1,283	1,074	1,114
Aviation Gasoline[d]	**374**	**329**	**302**	**291**	**281**	**251**	**260**	**294**	**278**	**263**	**235**	**221**	**225**	**225**	**209**
General Aviation Aircraft	374	329	302	291	281	251	260	294	278	263	235	221	225	225	209
Residual Fuel Oil[d, e]	**2,006**	**2,587**	**2,963**	**1,066**	**1,522**	**662**	**1,245**	**1,713**	**2,046**	**2,579**	**1,812**	**1,241**	**1,818**	**1,723**	**1,410**
Ships and Other Boats	2,006	2,587	2,963	1,066	1,522	662	1,245	1,713	2,046	2,579	1,812	1,241	1,818	1,723	1,410
Natural Gas [d] (trillion cubic feet)	**0.7**	**0.7**	**0.7**	**0.6**	**0.7**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.7**	**0.7**	**0.7**	**0.7**	**0.8**
Passenger Cars	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Light-Duty Trucks	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Buses	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Pipelines	0.7	0.7	0.6	0.6	0.7	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7
LPG[d]	**265**	**206**	**138**	**159**	**166**	**207**	**222**	**327**	**320**	**257**	**468**	**331**	**348**	**390**	**401**
Buses	-	1.6	1.5	0.3	0.6	0.7	0.7	1.0	1.0	-	-	-	-	-	-
Light-Duty Trucks	106	98	88	108	117	144	167	247	229	185	340	228	243	274	281
Medium- and Heavy-Duty Trucks	159	106	49	51	49	62	55	79	89	72	128	103	106	117	120
Electricity[d,f]	**4,751**	**4,975**	**5,382**	**5,724**	**5,517**	**6,810**	**7,224**	**7,506**	**7,358**	**8,173**	**7,700**	**7,781**	**7,712**	**7,672**	**7,320**
Rail	4,751	4,975	5,382	5,724	5,517	6,810	7,224	7,506	7,358	8,173	7,700	7,781	7,712	7,672	7,320

[a] In 2011, FHWA changed its methodology for Table VM-1, which impacts estimates for the 2007-2012 time period. These methodological changes include how on-road vehicles are classified, moving from a system based on body-type to one that is based on wheelbase. This resulted in large changes in fuel consumption data by vehicle class between 2006 and 2007.

[b] Figures do not include ethanol blended in motor gasoline. Net carbon fluxes associated with ethanol are accounted for in the Land Use, Land-Use Change and Forestry chapter.
[c] Fluctuations in recreational boat gasoline estimates reflect the use of this category to reconcile bottom-up values with EIA total gasoline estimates.
[d] Estimated based on EIA transportation sector energy estimates by fuel type, with bottom-up activity data used for apportionment to modes.
[e] Fluctuations in reported fuel consumption may reflect data collection problems.
[f] Million Kilowatt-hours
+ Less than 0.05 million gallons or 0.05 trillion cubic feet
- Unreported or zero

Table A-91: Energy Consumption by Fuel and Vehicle Type (Tbtu)

Fuel/Vehicle Type	1990	1995	2000	2001	2002	2003	2004	2005	2006	2007[a]	2008	2009	2010	2011	2012
Motor Gasoline[b]	**13,813**	**14,679**	**16,015**	**16,198**	**16,524**	**16,600**	**16,850**	**16,730**	**16,517**	**16,470**	**15,844**	**15,818**	**15,769**	**15,459**	**15,419**
Passenger Cars	8,725	8,437	9,038	9,113	9,289	9,004	8,968	9,268	8,901	11,158	10,731	10,687	10,653	10,598	10,592
Light-Duty Trucks	4,340	5,509	6,298	6,358	6,503	6,937	7,216	6,743	6,890	4,399	4,190	4,263	4,257	4,055	4,017
Motorcycles	24	25	26	24	24	23	24	23	26	59	62	60	53	51	59
Buses	5	5	5	5	5	4	6	5	5	10	11	11	11	11	11
Medium- and Heavy-Duty Trucks	544	506	508	495	501	431	436	492	498	650	661	611	611	562	558
Recreational Boats[c]	175	197	139	204	203	202	200	199	196	193	189	187	184	182	181
Distillate Fuel Oil (Diesel Fuel)	**3,555**	**4,383**	**5,442**	**5,417**	**5,596**	**5,711**	**5,918**	**6,194**	**6,359**	**6,440**	**6,107**	**5,539**	**5,765**	**5,899**	**5,887**
Passenger Cars	107	106	49	50	51	57	58	57	56	56	50	49	51	56	56
Light-Duty Trucks	155	201	272	281	296	368	391	349	362	184	164	164	170	178	178
Buses	108	118	138	126	119	129	183	143	145	215	205	191	190	205	220
Medium- and Heavy-Duty Trucks	2,576	3,223	4,186	4,178	4,357	4,374	4,521	4,876	5,004	5,200	4,950	4,491	4,676	4,718	4,735
Recreational Boats	26	32	37	38	39	40	41	42	43	45	46	47	48	49	50
Ships and Other Boats	102	167	191	173	167	163	112	109	101	111	107	107	102	139	103
Rail	480	536	569	571	567	579	611	617	647	630	585	490	528	555	544
Jet Fuel[d]	**2,590**	**2,429**	**2,700**	**2,626**	**2,565**	**2,482**	**2,585**	**2,622**	**2,524**	**2,485**	**2,396**	**2,134**	**2,097**	**2,030**	**1,985**
Commercial Aircraft	1,562	1,638	1,981	1,771	1,725	1,747	1,775	1,887	1,948	1,986	1,809	1,699	1,611	1,629	1,611
General Aviation Aircraft	545	454	427	537	556	449	515	484	350	276	362	241	314	256	224
Military Aircraft	484	337	293	318	285	287	295	251	227	224	225	194	173	145	150
Aviation Gasoline[d]	**45**	**40**	**36**	**35**	**34**	**30**	**31**	**35**	**33**	**32**	**28**	**27**	**27**	**27**	**25**
General Aviation Aircraft	45	40	36	35	34	30	31	35	33	32	28	27	27	27	25
Residual Fuel Oil[d, e]	**300**	**387**	**443**	**159**	**228**	**99**	**186**	**256**	**306**	**386**	**271**	**186**	**272**	**258**	**211**
Ships and Other Boats	300	387	443	159	228	99	186	256	306	386	271	186	272	258	211
Natural Gas[d]	**680**	**724**	**672**	**658**	**699**	**627**	**602**	**624**	**625**	**663**	**692**	**715**	**719**	**734**	**777**
Passenger Cars	-	2	-	-	-	-	-	-	-	-	-	-	-	-	-
Light-Duty Trucks	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Buses	-	1	8	9	12	14	16	16	16	19	21	22	20	20	20
Pipelines	680	721	664	649	687	614	586	608	609	645	672	693	699	713	757
LPG[d]	**23**	**18**	**12**	**14**	**14**	**18**	**19**	**28**	**27**	**22**	**40**	**28**	**29**	**33**	**34**
Buses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Light-Duty Trucks	9	8	8	9	10	12	14	21	20	16	29	19	21	23	24
Medium- and Heavy-Duty Trucks	14	9	4	4	4	5	5	7	8	6	11	9	9	10	10
Electricity[d]	**16**	**17**	**18**	**20**	**19**	**23**	**25**	**26**	**25**	**28**	**26**	**27**	**26**	**26**	**25**
Rail	16	17	18	20	19	23	25	26	25	28	26	27	26	26	25
Total	**21,022**	**22,676**	**25,339**	**25,127**	**25,679**	**25,592**	**26,216**	**26,515**	**26,417**	**26,526**	**25,405**	**24,474**	**24,705**	**24,466**	**24,362**

[a] In 2011, FHWA changed its methodology for Table VM-1, which impacts estimates for the 2007-2012 time period. These methodological changes include how on-road vehicles are classified, moving from a system based on body-type to one that is based on wheelbase. This resulted in large changes in fuel consumption data by vehicle class between 2006 and 2007.

[b] Figures do not include ethanol blended in motor gasoline. Net carbon fluxes associated with ethanol are accounted for in the Land Use, Land-Use Change and Forestry chapter.

[c] Fluctuations in recreational boat gasoline estimates reflect the use of this category to reconcile bottom-up values with EIA total gasoline estimates.

[d] Estimated based on EIA transportation sector energy estimates, with bottom-up data used for apportionment to modes.

[e] Fluctuations in reported fuel consumption may reflect data collection problems. Residual fuel oil for ships and other boats data is based on EIA's February 2013 Monthly Energy Review data.

- Unreported or zero

Table A-92. Biofuel Consumption by Fuel Type (million gallons)

Fuel Type	1990	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Ethanol	712.6	1,327	1,591	1,661	1,977	2,690	3,377	3,862	5,210	6,567	9,269	10,543	12,282	12,326	12,316
Biodiesel	NA	NA	NA	10	16	14	27	91	261	354	304	322	260	886	895

NA (Not Available)

Estimates of CH_4 and N_2O Emissions

Mobile source emissions of greenhouse gases other than CO_2 are reported by transport mode (e.g., road, rail, aviation, and waterborne), vehicle type, and fuel type. Emissions estimates of CH_4 and N_2O were derived 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 fuel consumption and vehicle miles traveled (VMT). These estimates were then multiplied by emission factors, expressed as grams per unit of fuel consumed or per vehicle mile.

Methodology for On-Road Gasoline and Diesel Vehicles

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

VMT by vehicle type (e.g., passenger cars, light-duty trucks, medium- and heavy-duty trucks,[44] buses, and motorcycles) were obtained from the Federal Highway Administration's (FHWA) *Highway Statistics* (FHWA 1996 through 2014).[45] As these vehicle categories are not fuel-specific, VMT for each vehicle type was disaggregated by fuel type (gasoline, diesel) so that the appropriate emission factors could be applied. VMT from *Highway Statistics* Table VM-1 (FHWA 1996 through 2014) was allocated to fuel types (gasoline, diesel, other) using historical estimates of fuel shares reported in the Appendix to the *Transportation Energy Data Book* (DOE 1993 through 2013). These fuel shares are drawn from various sources, including the Vehicle Inventory and Use Survey, the National Vehicle Population Profile, and the American Public Transportation Association. The fuel shares were first adjusted proportionately so that the gasoline and diesel shares for each vehicle type summed to 100 percent in order to develop an interim estimate of VMT for each vehicle/fuel type category that summed to the total national VMT estimate. VMT for alternative fuel vehicles (AFVs) was calculated separately, and the methodology is explained in the following section on AFVs. Estimates of VMT from AFVs were then subtracted from the appropriate total VMT estimates to develop the final VMT estimates by vehicle/fuel type category.[46] The resulting national VMT estimates for gasoline and diesel on-road vehicles are presented in Table A- 93 and Table A- 94, respectively.

Total VMT for each on-road category (i.e., gasoline passenger cars, light-duty gasoline trucks, heavy-duty gasoline vehicles, diesel passenger cars, light-duty diesel trucks, medium- and heavy-duty diesel vehicles, and motorcycles) were distributed across 31 model years shown for 2012 in Table A- 97. Distributions for 1990-2012 are presented in the Inventory Docket [47]. This distribution was derived by weighting the appropriate age distribution of the U.S. vehicle fleet according to vehicle registrations by the average annual age-specific vehicle mileage accumulation of U.S. vehicles. Age distribution values were obtained from EPA's MOBILE6 model for all years before 1999 (EPA 2000) and EPA's MOVES model for years 2009 forward (EPA 2013c).[48] Age-specific vehicle mileage accumulation was obtained from EPA's MOBILE6 model (EPA 2000).

Step 2: Allocate VMT Data to Control Technology Type

VMT by vehicle type for each model year was distributed across various control technologies as shown in Table A- 101 through Table A- 104. The categories "EPA Tier 0" and "EPA Tier 1" were used instead of 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, EPA Tier 2, and LEV refer to U.S. emission regulations, rather than control technologies; however, each does

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[44] Medium- and heavy-duty trucks correspond to FHWA's reporting categories of single-unit trucks and combination trucks. Single-unit trucks are defined as single frame trucks that have 2-axles and at least 6 tires or a gross vehicle weight rating (GVWR) exceeding 10,000 lbs.

[45] In 2011 FHWA changed its methods for estimated vehicle miles traveled (VMT) and related data. These methodological changes included how vehicles are classified, moving from a system based on body-type to one that is based on wheelbase. These changes were first incorporated for the 2010 Inventory and apply to the 2007-12 time period. This resulted in large changes in VMT data by vehicle class, thus leading to a shift in emissions among on-road vehicle classes. For example, the category "Passenger Cars" has been replaced by "Light-duty Vehicles-Short Wheelbase" and "Other 2 axle-4 Tire Vehicles" has been replaced by "Light-duty Vehicles, Long Wheelbase." This change in vehicle classification has moved some smaller trucks and sport utility vehicles from the light truck category to the passenger vehicle category in this emission inventory. These changes are reflected in a large drop in light-truck emissions between 2006 and 2007.

[46] In Inventories through 2002, gasoline-electric hybrid vehicles were considered part of an "alternative fuel and advanced technology" category. However, vehicles are now only separated into gasoline, diesel, or alternative fuel categories, and gas-electric hybrids are now considered within the gasoline vehicle category.

[47] Available on CD by request.

[48] Age distributions were held constant for the period 1990-1998, and reflect a 25-year vehicle age span. EPA (2010) provides a variable age distribution and 31-year vehicle age span beginning in year 1999.

correspond to particular combinations of control technologies and engine design. EPA Tier 2 and its predecessors EPA Tier 1 and Tier 0 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).[49] EPA Tier 2 regulations affect vehicles produced starting in 2004 and are responsible for a noticeable decrease in N_2O emissions compared EPA Tier 1 emissions technology (EPA 1999b).

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 2007 were determined using confidential engine family sales data submitted to EPA (EPA 2007b). Vehicle classes and emission standard tiers to which each engine family was certified were taken from annual certification test results and data (EPA 2007a). This information was used to determine the fraction of sales of each class of vehicle that met EPA Tier 0, EPA Tier 1, Tier 2, 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. Tier 2 began initial phase-in by 2004.

Step 3: Determine CH_4 and N_2O Emission Factors by Vehicle, Fuel, and Control Technology Type

Emission factors for gasoline and diesel on-road vehicles utilizing Tier 2 and Low Emission Vehicle (LEV) technologies were developed by ICF (2006b); all other gasoline and diesel on-road vehicle emissions factors were developed by ICF (2004).These factors were based on EPA,CARB and Environment Canada laboratory test results of different vehicle and control technology types. The EPA, CARB and Environment Canada tests were designed following the Federal Test Procedure (FTP), which covers three separate driving segments, since vehicles emit varying amounts of GHGs depending on the driving segment. These driving segments are: (1) a transient driving cycle that includes cold start and running emissions, (2) a cycle that represents running emissions only, and (3) a transient driving cycle that includes hot start and running emissions. For each test run, a bag was affixed to the tailpipe of the vehicle and the exhaust was collected; the content of this bag was later analyzed to determine quantities of gases present. The emission characteristics of segment 2 was used to define running emissions, and subtracted from the total FTP emissions to determine start emissions. These were then recombined based upon MOBILE6.2's ratio of start to running emissions for each vehicle class to approximate average driving characteristics.

Step 4: Determine the Amount of CH_4 and N_2O Emitted by Vehicle, Fuel, and Control Technology Type

Emissions of CH_4 and N_2O were then calculated by multiplying total VMT by vehicle, fuel, and control technology type by the emission factors developed in Step 3.

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 "VMT Projections for Alternative Fueled and Advanced Technology Vehicles through 2025" (Browning 2003). Alternative Fuels include Compressed Natural Gas (CNG), Liquid Natural Gas (LNG), Liquefied Petroleum Gas (LPG), Ethanol, Methanol, and Electric Vehicles (battery powered). Most of the vehicles that use these fuels run on 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.[50] The data obtained include vehicle fuel use and total number of vehicles in use from 1992 through 2007. Because AFVs run on different fuel types, their fuel use characteristics are not directly comparable. Accordingly, fuel economy for each vehicle type is expressed in gasoline equivalent terms, i.e., how much gasoline contains the equivalent amount of energy as the alternative fuel. 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, Kassoy 2001). These ratios 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 use that fuel. Total VMT per vehicle type for each calendar year was then determined by dividing the energy usage by the fuel economy. Note that for AFVs capable of running on both/either traditional and alternative fuels, the VMT given reflects only those miles driven that

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[49] For further description, see "Definitions of Emission Control Technologies and Standards" section of this annex below.

[50] Fuel types used in combination depend on the vehicle class. For light-duty vehicles, gasoline is generally blended with ethanol and diesel is blended with biodiesel; dual-fuel vehicles can run on gasoline or an alternative fuel – either natural gas or LPG – but not at the same time, while flex-fuel vehicles are designed to run on E85 (85% ethanol) or gasoline, or any mixture of the two in between. Heavy-duty vehicles are more likely to run on diesel fuel, natural gas, or LPG,.

were powered by the alternative fuel, as explained in Browning (2003). VMT estimates for AFVs by vehicle category (passenger car, light-duty truck, heavy-duty vehicles) are shown in Table A- 95, while more detailed estimates of VMT by control technology are shown in Table A- 96.

Step 2: Determine CH_4 and N_2O Emission Factors by Vehicle and Alternative Fuel Type

CH_4 and N_2O emission factors for alternative fuel vehicles (AFVs) are calculated according to studies by Argonne National Laboratory (2006) and Lipman & Delucchi (2002), and are reported in ICF (2006a). In these studies, N_2O and CH_4 emissions for AFVs were expressed as a multiplier corresponding to conventional vehicle counterpart emissions. Emission estimates in these studies represent the current AFV fleet and were compared against Tier 1 emissions from light-duty gasoline vehicles to develop new multipliers. Alternative fuel heavy-duty vehicles were compared against gasoline heavy-duty vehicles as most alternative fuel heavy-duty vehicles use catalytic after treatment and perform more like gasoline vehicles than diesel vehicles. These emission factors are shown in Table A- 106.

Step 3: Determine the Amount of CH_4 and N_2O Emitted by Vehicle and Fuel Type

Emissions of CH_4 and N_2O were calculated by multiplying total VMT for each vehicle and fuel type (Step 1) by the appropriate emission factors (Step 2).

Methodology for Non-Road Mobile Sources

CH_4 and N_2O emissions from non-road mobile sources were estimated by applying emission factors to the amount of fuel consumed by mode and vehicle type.

Activity data for non-road vehicles include annual fuel consumption statistics by transportation mode and fuel type, as shown in Table A- 100. Consumption data for ships and other boats (i.e., vessel bunkering) were obtained from DHS (2008) and EIA (1991 through 2013) for distillate fuel, and DHS (2008) and EIA (2013a) for residual fuel; marine transport fuel consumption data for U.S. territories (EIA 2008b) were added to domestic consumption, and this total was reduced by the amount of fuel used for international bunkers.[51] Gasoline consumption by recreational boats was obtained from EPA's NONROAD model (EPA 2013b). Annual diesel consumption for Class I rail was obtained from the Association of American Railroads (AAR 2008 through 2013), diesel consumption from commuter rail was obtained from APTA (2007 through 2013) and Gaffney (2007), and consumption by Class II and III rail was provided by Benson (2002 through 2004) and Whorton (2006 through 2012).[52] Diesel consumption by commuter and intercity rail was obtained from DOE (1993 through 2013). Data on the consumption of jet fuel and aviation gasoline in aircraft were obtained from EIA (2014) and FAA (2014), as described in Annex 2.1: Methodology for Estimating Emissions of CO_2 from Fossil Fuel Combustion, and were reduced by the amount allocated to international bunker fuels (DESC 2013 and FAA 2014). Pipeline fuel consumption was obtained from EIA (2007 through 2012) (note: pipelines are a transportation source but are stationary, not mobile, sources). Data on fuel consumption by all non-transportation mobile sources[53] were obtained from EPA's NONROAD model (EPA 2013b) and from FHWA (1996 through 2014) for gasoline consumption for trucks used off-road.

Emissions of CH_4 and N_2O from non-road 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 A- 107).

Estimates of NO_x, CO, and NMVOC Emissions

The emission estimates of NO_x, CO, and NMVOCs from mobile combustion (transportation) were obtained from preliminary data (EPA 2010), which, in final iteration, will be published on the EPA's National Emission Inventory (NEI) Air Pollutant Emission Trends web site. This EPA report provides emission estimates for these gases by fuel type using a procedure whereby emissions were calculated using basic activity data, such as amount of fuel delivered or miles traveled, as indicators of emissions. Table A- 108 through Table A- 110 provides complete emission estimates for 1990 through 2012.

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[51] See International Bunker Fuels section of the Energy Chapter.

[52] Diesel consumption from Class II and Class III railroad were unavailable for 2012. Values are proxied from 2010, which is the last year the data was available.

[53] "Non-transportation mobile sources" are defined as any vehicle or equipment not used on the traditional road system, but excluding aircraft, rail and watercraft. This category includes snowmobiles, golf carts, riding lawn mowers, agricultural equipment, and trucks used for off-road purposes, among others.

Table A- 93: Vehicle Miles Traveled for Gasoline On-Road Vehicles (10^9 Miles)

Year	Passenger Cars	Light-Duty Trucks	Heavy-Duty Vehicles	Motorcycles
1990	1,391.2	554.3	25.4	9.6
1991	1,341.7	627.2	25.0	9.2
1992	1,354.8	682.9	24.8	9.6
1993	1,356.5	720.5	24.5	9.9
1994	1,387.5	738.8	25.0	10.2
1995	1,420.6	762.5	24.7	9.8
1996	1,454.7	788.0	24.0	9.9
1997	1,488.5	820.8	23.6	10.1
1998	1,536.6	836.8	23.6	10.3
1999	1,559.1	867.4	23.8	10.6
2000	1,591.5	886.7	23.6	10.5
2001	1,619.3	904.9	23.2	9.6
2002	1,649.2	925.8	23.1	9.6
2003	1,662.6	943.0	23.5	9.6
2004	1,690.2	984.2	23.9	10.1
2005	1,698.8	997.8	24.2	10.5
2006	1,681.0	1,037.5	24.4	12.0
2007[a]	2,092.8	561.5	33.7	21.4
2008	2,013.6	579.5	34.5	20.8
2009	2,004.6	591.1	32.1	20.8
2010	2,014.6	595.7	31.9	18.5
2011	2,034.6	576.9	29.7	18.5
2012	2,051.4	573.4	29.9	21.3

Source: Derived from FHWA (1996 through 2014).

[a] In 2011, FHWA changed its methodology for Table VM-1, which impacts estimates for the 2007-2012 time period. These methodological changes include how on-road vehicles are classified, moving from a system based on body-type to one that is based on wheelbase. This resulted in large changes in VMT data by vehicle class between 2006 and 2007

Table A- 94: Vehicle Miles Traveled for Diesel On-Road Vehicles (10^9 Miles)

Year	Passenger Cars	Light-Duty Trucks	Heavy-Duty Vehicles[b]
1990	16.9	19.7	125.5
1991	16.3	21.6	129.3
1992	16.5	23.4	133.5
1993	17.9	24.7	140.3
1994	18.3	25.3	150.5
1995	17.3	26.9	158.7
1996	14.7	27.8	164.3
1997	13.5	29.0	173.4
1998	12.4	30.5	178.4
1999	9.4	32.6	185.3
2000	8.0	35.2	188.0
2001	8.1	37.0	191.1
2002	8.3	38.9	196.4
2003	8.3	39.7	199.1
2004	8.4	41.3	201.6
2005	8.4	41.9	202.6
2006	8.3	43.5	201.0
2007	10.3	23.4	280.2
2008	9.9	24.2	286.4
2009	9.8	24.7	265.8
2010	9.9	24.9	264.3
2011	10.0	24.2	247.5
2012	10.1	24.1	249.0

Source: Derived from FHWA (1996 through 2014).

[a] In 2011, FHWA changed its methodology for Table VM-1, which impacts estimates for the 2007-2012 time period. These methodological changes include how on-road vehicles are classified, moving from a system based on body-type to one that is based on wheelbase. This resulted in large changes in VMT data by vehicle class between 2006 and 2007.

[b] Heavy-Duty Vehicles includes Medium-Duty Trucks, Heavy-Duty Trucks, and Buses

Table A- 95: Vehicle Miles Traveled for Alternative Fuel On-Road Vehicles (10^9 Miles)

Year	Passenger Cars	Light-Duty Trucks	Heavy-Duty Vehicles[a]
1990	0.2	0.7	1.1
1991	0.2	0.6	1.0
1992	0.3	0.6	0.9
1993	0.3	0.6	1.3
1994	0.3	0.5	1.2
1995	0.4	0.6	1.2
1996	0.5	0.7	1.2
1997	0.6	0.9	1.3
1998	0.6	1.0	1.4
1999	0.6	1.0	1.3
2000	0.8	1.2	1.5
2001	0.9	1.2	1.8
2002	1.0	1.3	2.0
2003	1.2	1.4	2.1
2004	1.3	1.6	2.2
2005	1.2	1.4	2.7
2006	1.3	1.5	3.9
2007	1.3	1.6	4.8
2008	1.3	1.8	4.6
2009	1.2	1.8	4.8
2010	1.3	2.1	4.1
2011	1.6	3.1	4.2
2012	1.8	3.6	4.2

Source: Derived from Browning (2003).

[a] Heavy Duty-Vehicles includes medium-duty trucks, heavy-duty trucks, and buses.

Table A- 96: Detailed Vehicle Miles Traveled for Alternative Fuel On-Road Vehicles (10^6 Miles)

Vehicle Type	1990	1995	2000	2001	2002	2003	2004	2005[a]	2006	2007	2008	2009	2010	2011	2012
Passenger Cars	**206.3**	**400.6**	**788.1**	**922.0**	**1,042.4**	**1,172.9**	**1,273.0**	**1,243.1**	**1,296.4**	**1,295.4**	**1,268.7**	**1,242.1**	**1,252.2**	**1,604.1**	**1,849.4**
Methanol-Flex Fuel ICE	+	40.9	13.2	10.1	7.8	6.4	3.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ethanol-Flex Fuel ICE	+	2.2	120.4	147.9	189.1	271.2	311.5	391.7	412.8	448.6	459.9	488.4	546.0	569.3	725.3
CNG ICE	10.6	28.0	68.9	78.1	83.0	85.0	112.1	62.6	62.5	58.4	53.0	47.3	50.4	53.4	54.8
CNG Bi-fuel	28.2	75.1	202.9	236.6	267.2	283.5	274.1	187.6	193.8	180.0	170.9	159.7	163.2	166.0	172.7
LPG ICE	20.6	40.3	41.9	45.0	48.8	43.1	37.4	40.7	37.3	24.6	25.9	14.2	11.9	11.9	11.9
LPG Bi-fuel	146.9	201.7	197.6	224.8	237.9	221.9	199.4	207.1	186.4	121.4	112.0	88.7	83.1	83.0	83.4
Biodiesel (BD20)	+	+	8.2	8.3	13.4	13.6	62.3	125.1	186.4	246.1	235.8	236.6	189.9	187.4	185.8
NEVs	+	5.2	62.4	88.4	98.8	114.4	124.8	104.2	99.2	99.4	99.1	97.1	97.7	97.5	98.1
Electric Vehicle	+	7.2	72.6	82.8	96.3	133.8	147.8	124.2	118.1	116.9	112.0	110.0	109.8	296.5	374.3
Light-Duty Trucks	**660.7**	**606.8**	**1,162.0**	**1,235.1**	**1,344.2**	**1,447.5**	**1,567.3**	**1,401.0**	**1,545.6**	**1,648.5**	**1,779.6**	**1,806.9**	**2,096.3**	**3,113.9**	**3,602.1**
Ethanol-Flex Fuel ICE	+	1.3	122.6	150.1	179.1	279.1	353.7	420.8	532.4	702.4	864.0	1,021.1	1,363.4	2,378.8	2,864.4
CNG ICE	10.9	29.6	145.9	145.7	153.4	158.0	162.2	65.5	65.5	64.7	63.0	58.2	60.7	66.1	72.0
CNG Bi-fuel	24.2	71.0	280.1	280.1	301.2	313.4	330.0	171.4	178.6	175.4	169.6	157.5	161.6	165.2	171.6
LPG ICE	56.9	48.5	58.4	64.4	68.2	64.9	61.5	60.1	60.1	43.8	43.8	33.0	30.3	30.2	28.8
LPG Bi-fuel	568.7	449.4	511.9	522.9	557.1	541.8	525.6	513.2	486.1	383.7	361.4	259.7	239.9	238.9	234.8
Biodiesel (BD20)	+	+	8.2	8.4	17.1	16.9	55.9	109.4	163.8	219.2	219.0	219.8	176.5	170.7	166.1
Electric Vehicle	+	7.1	35.0	63.4	68.2	73.4	78.3	60.1	58.4	58.0	57.5	55.8	61.9	61.8	62.1
Medium-Duty Trucks	**508.0**	**458.4**	**629.6**	**862.5**	**977.7**	**899.7**	**856.6**	**802.6**	**628.8**	**693.1**	**716.3**	**629.8**	**578.6**	**578.7**	**573.3**
CNG Bi-fuel	2.3	20.1	117.0	203.2	228.2	245.3	241.9	146.7	112.5	154.4	188.3	178.8	187.6	198.9	206.1
LPG ICE	24.3	20.0	29.7	41.9	48.3	43.9	40.7	40.5	33.8	31.3	35.0	31.0	29.9	30.5	30.0
LPG Bi-fuel	481.4	418.3	475.9	609.7	671.8	585.0	535.7	517.2	326.5	298.2	289.0	215.2	211.7	212.6	212.3
Biodiesel (BD20)	+	+	7.0	7.6	29.4	25.6	38.2	98.2	156.0	209.1	204.0	204.8	149.4	136.7	124.9
Heavy-Duty Trucks	**523.9**	**627.0**	**712.3**	**820.5**	**845.2**	**1,041.2**	**1,093.9**	**1,644.2**	**2,867.9**	**3,627.7**	**3,416.3**	**3,639.5**	**3,083.2**	**3,107.6**	**3,141.5**
Neat Methanol ICE	3.0	7.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Neat Ethanol ICE	+	2.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CNG ICE	12.7	32.2	83.7	149.0	146.3	183.6	187.7	408.0	491.8	557.2	647.6	843.7	900.0	959.6	1,011.7
LPG ICE	36.3	46.3	48.3	57.1	60.9	73.4	70.8	69.0	81.9	78.4	76.9	74.7	74.4	75.0	72.0
LPG Bi-fuel	471.9	531.9	529.7	558.0	548.5	650.2	626.7	499.2	530.0	522.5	516.8	513.4	515.2	515.0	507.2
LNG	+	6.9	22.2	26.9	28.6	56.8	108.1	115.9	123.2	127.5	129.5	131.9	136.6	139.8	143.3
Biodiesel (BD20)	+	+	28.3	29.5	60.9	77.1	100.6	552.2	1,641.1	2,342.2	2,045.4	2,075.8	1,456.9	1,418.3	1,407.2
Buses	**41.4**	**80.5**	**111.9**	**133.1**	**140.3**	**139.0**	**229.3**	**250.8**	**406.5**	**468.7**	**481.7**	**500.4**	**493.8**	**493.6**	**513.2**
Neat Methanol ICE	1.9	3.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Neat Ethanol ICE	0.1	2.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CNG ICE	11.2	37.5	53.4	65.0	65.5	64.3	145.2	160.0	165.1	179.8	202.5	220.2	238.0	254.7	273.2
LPG ICE	28.2	30.9	35.6	36.9	36.4	34.1	38.9	30.3	28.9	28.9	28.7	28.4	28.4	28.3	27.7
LNG	+	4.3	13.3	21.0	22.3	23.6	25.7	28.6	30.0	33.5	37.6	37.8	38.1	38.2	38.5
Biodiesel (BD20)	+	+	4.5	4.7	9.9	10.5	13.1	15.6	165.1	209.1	194.0	194.8	170.0	152.9	151.6
Electric	+	2.0	5.1	5.6	6.3	6.6	6.4	16.2	17.3	17.1	18.4	18.5	18.5	18.7	21.3
Total VMT	**1,940.3**	**2,173.4**	**3,403.9**	**3,973.1**	**4,349.9**	**4,700.4**	**5,020.2**	**5,341.7**	**6,745.2**	**7,733.3**	**7,662.6**	**7,818.6**	**7,503.9**	**8,897.8**	**9,679.5**

Source: Derived from Browning (2003).

Note: Throughout the rest of this Inventory, medium-duty trucks are grouped with heavy-duty trucks; they are reported separately here because these two categories may run on a slightly different range of fuel types.

[a] In 2011, EIA changed its reporting methodology for 2005-2010 data. EIA provided more detail on alternative fuel vehicle use by vehicle class. The fuel use breakdown by vehicle class had previously been based on estimates of the distribution of fuel use by vehicle class. The new data from EIA allowed actual data to be used for fuel use, and resulted in greater share of heavy-duty AFV VMT estimated for 2005-2010. The source of this data is the U.S. Energy Information Administration, Office of Energy Consumption and Efficiency Statistics and the DOE/GSA Federal Automotive Statistical Tool (FAST).

+ Less than 0.05 million vehicle miles traveled

Table A- 97: Age Distribution by Vehicle/Fuel Type for On-Road Vehicles,[a] 2012

Vehicle Age	LDGV	LDGT	HDGV	LDDV[b]	LDDT	HDDV	MC
0	7.7%	6.2%	6.0%	10.1%	6.3%	6.2%	11.0%
1	7.0%	6.0%	5.6%	9.3%	6.1%	5.8%	9.0%
2	6.2%	5.4%	5.2%	8.1%	5.5%	5.4%	6.8%
3	5.1%	3.8%	5.0%	6.8%	3.8%	5.3%	4.8%
4	5.7%	4.7%	5.4%	7.5%	4.8%	5.8%	9.0%
5	6.3%	6.8%	5.5%	8.3%	6.2%	5.9%	8.1%
6	6.3%	6.8%	5.5%	8.3%	5.8%	7.1%	7.7%
7	6.1%	7.0%	5.3%	8.0%	6.0%	6.6%	6.7%
8	5.8%	6.7%	4.2%	7.6%	8.6%	5.2%	5.7%
9	5.6%	6.1%	3.3%	7.4%	6.1%	4.0%	4.8%
10	5.7%	5.6%	2.9%	7.6%	6.4%	3.6%	4.3%
11	5.7%	5.2%	3.3%	7.5%	6.5%	3.9%	3.6%
12	5.5%	4.8%	3.6%	0.0%	5.3%	4.5%	2.9%
13	4.5%	4.0%	3.6%	0.0%	5.6%	4.7%	2.2%
14	3.5%	3.5%	2.9%	0.0%	1.3%	3.6%	1.9%
15	2.9%	2.8%	2.2%	0.0%	3.2%	2.8%	1.8%
16	2.4%	2.5%	2.4%	0.0%	2.1%	2.6%	1.6%
17	1.9%	2.1%	2.8%	0.0%	2.0%	2.8%	1.2%
18	1.5%	1.8%	2.7%	0.0%	1.7%	2.4%	1.4%
19	1.1%	1.5%	2.0%	0.0%	1.2%	1.8%	1.1%
20	0.8%	1.1%	1.5%	0.0%	0.9%	1.2%	0.9%
21	0.6%	0.9%	1.5%	0.0%	0.7%	1.1%	0.7%
22	0.5%	0.9%	1.8%	0.0%	0.6%	1.3%	0.6%
23	0.4%	0.8%	2.5%	0.0%	0.5%	1.4%	0.4%
24	0.4%	0.7%	2.3%	0.0%	0.4%	1.2%	0.4%
25	0.3%	0.6%	2.0%	0.0%	0.3%	0.9%	0.4%
26	0.2%	0.5%	2.6%	0.0%	0.4%	0.9%	0.3%
27	0.2%	0.4%	2.0%	0.6%	0.4%	0.7%	0.3%
28	0.1%	0.3%	1.2%	0.7%	0.4%	0.4%	0.2%
29	0.1%	0.2%	1.8%	0.8%	0.3%	0.4%	0.2%
30	0.1%	0.2%	1.4%	1.5%	0.4%	0.3%	0.2%
Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

Source: EPA (2013c).

[a] The following abbreviations correspond to vehicle types: LDGV (light-duty gasoline vehicles), LDGT (light-duty gasoline trucks), HDGV (heavy-duty gasoline vehicles), LDDV (light-duty diesel vehicles), LDDT (light-duty diesel trucks), HDDV (heavy-duty diesel vehicles), and MC (motorcycles).

[b] According to EPA's MOVES model, sales of diesel passenger cars 12-26 years of age was very small compared to total passenger car sales, so the calculated fraction of these vehicles was stored as zero.

Table A- 98: Annual Average Vehicle Mileage Accumulation per Vehicle[a] (miles)

Vehicle Age	LDGV	LDGT	HDGV	LDDV	LDDT	HDDV	MC[b]
0	14,910	19,906	20,218	14,910	26,371	28,787	4,786
1	14,174	18,707	18,935	14,174	24,137	26,304	4,475
2	13,475	17,559	17,100	13,475	22,095	24,038	4,164
3	12,810	16,462	16,611	12,810	20,228	21,968	3,853
4	12,178	15,413	15,560	12,178	18,521	20,078	3,543
5	11,577	14,411	14,576	11,577	16,960	18,351	3,232
6	11,006	13,454	13,655	11,006	15,533	16,775	2,921
7	10,463	12,541	12,793	10,463	14,227	15,334	2,611
8	9,947	11,671	11,987	9,947	13,032	14,019	2,300
9	9,456	10,843	11,231	9,456	11,939	12,817	1,989
10	8,989	10,055	10,524	8,989	10,939	11,719	1,678
11	8,546	9,306	9,863	8,546	10,024	10,716	1,368
12	8,124	8,597	9,243	8,124	9,186	9,799	1,368
13	7,723	7,925	8,662	7,723	8,420	8,962	1,368
14	7,342	7,290	8,028	7,342	7,718	8,196	1,368
15	6,980	6,690	7,610	6,980	7,075	7,497	1,368
16	6,636	6,127	7,133	6,636	6,487	6,857	1,368
17	6,308	5,598	6,687	6,308	5,948	6,273	1,368
18	5,997	5,103	6,269	5,997	5,454	5,739	1,368
19	5,701	4,642	5,877	5,701	5,002	5,250	1,368
20	5,420	4,214	5,510	5,420	4,588	4,804	1,368
21	5,152	3,818	5,166	5,152	4,209	4,396	1,368
22	4,898	3,455	4,844	4,898	3,861	4,023	1,368
23	4,656	3,123	4,542	4,656	3,542	3,681	1,368
24	4,427	2,822	4,259	4,427	3,250	3,369	1,368
25	4,427	2,822	4,259	4,427	3,250	3,369	1,368
26	4,427	2,822	4,259	4,427	3,250	3,369	1,368
27	4,427	2,822	4,259	4,427	3,250	3,369	1,368
28	4,427	2,822	4,259	4,427	3,250	3,369	1,368
29	4,427	2,822	4,259	4,427	3,250	3,369	1,368
30	4,427	2,822	4,259	4,427	3,250	3,369	1,368

Source: EPA (2000).

[a] The following abbreviations correspond to vehicle types: LDGV (light-duty gasoline vehicles), LDGT (light-duty gasoline trucks), HDGV (heavy-duty gasoline vehicles), LDDV (light-duty diesel vehicles), LDDT (light-duty diesel trucks), HDDV (heavy-duty diesel vehicles), and MC (motorcycles).

[b] 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 presented in aggregate.

Table A- 99: VMT Distribution by Vehicle Age and Vehicle/Fuel Type, [a] 2012

Vehicle Age	LDGV	LDGT	HDGV	LDDV[b]	LDDT	HDDV	MC
0	11.10%	10.47%	10.91%	13.33%	11.90%	12.17%	17.67%
1	9.64%	9.52%	9.55%	11.58%	10.54%	10.46%	13.48%
2	8.03%	8.14%	7.93%	9.65%	8.79%	8.90%	9.51%
3	6.36%	5.30%	7.40%	7.64%	5.59%	7.91%	6.17%
4	6.71%	6.15%	7.56%	8.05%	6.34%	7.93%	10.67%
5	7.02%	8.40%	7.17%	8.43%	7.53%	7.41%	8.80%
6	6.72%	7.81%	6.65%	8.07%	6.50%	8.10%	7.53%
7	6.16%	7.50%	6.10%	7.39%	6.14%	6.95%	5.90%
8	5.55%	6.61%	4.48%	6.67%	8.07%	4.99%	4.41%
9	5.14%	5.65%	3.30%	6.17%	5.25%	3.49%	3.22%
10	4.99%	4.80%	2.70%	5.99%	5.06%	2.86%	2.42%
11	4.70%	4.15%	2.93%	5.64%	4.70%	2.83%	1.67%
12	4.29%	3.48%	2.96%	0.00%	3.52%	3.05%	1.34%
13	3.32%	2.71%	2.76%	0.00%	3.39%	2.87%	1.01%
14	2.46%	2.15%	2.08%	0.00%	0.74%	2.03%	0.86%
15	1.93%	1.62%	1.50%	0.00%	1.62%	1.43%	0.82%
16	1.51%	1.29%	1.53%	0.00%	0.99%	1.22%	0.72%
17	1.15%	0.98%	1.65%	0.00%	0.84%	1.22%	0.54%
18	0.88%	0.80%	1.53%	0.00%	0.65%	0.95%	0.63%
19	0.61%	0.58%	1.04%	0.00%	0.45%	0.64%	0.51%
20	0.43%	0.40%	0.75%	0.00%	0.28%	0.40%	0.43%
21	0.31%	0.29%	0.70%	0.00%	0.20%	0.35%	0.34%
22	0.26%	0.25%	0.77%	0.00%	0.17%	0.37%	0.27%
23	0.20%	0.21%	1.00%	0.00%	0.13%	0.36%	0.20%
24	0.15%	0.17%	0.88%	0.00%	0.09%	0.28%	0.17%
25	0.11%	0.14%	0.77%	0.00%	0.07%	0.22%	0.17%
26	0.09%	0.12%	0.98%	0.00%	0.10%	0.22%	0.14%
27	0.07%	0.11%	0.75%	0.25%	0.09%	0.16%	0.12%
28	0.05%	0.08%	0.44%	0.28%	0.09%	0.10%	0.11%
29	0.03%	0.05%	0.68%	0.31%	0.08%	0.09%	0.08%
30	0.03%	0.05%	0.55%	0.58%	0.10%	0.07%	0.09%
Total	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**

Note: Estimated by weighting data in Table A- 97 by data in Table A- 98.

[a] The following abbreviations correspond to vehicle types: LDGV (light-duty gasoline vehicles), LDGT (light-duty gasoline trucks), HDGV (heavy-duty gasoline vehicles), LDDV (light-duty diesel vehicles), LDDT (light-duty diesel trucks), HDDV (heavy-duty diesel vehicles), and MC (motorcycles).

[b] According to EPA's MOVES model, sales of diesel passenger cars 12-26 years of age was very small compared to total passenger car sales, so the calculated fraction of these vehicles was stored as zero.

Table A- 100: Fuel Consumption for Off-Road Sources by Fuel Type (million gallons)

Vehicle Type/Year	1990	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Aircraft[a]	**19,560**	**18,320**	**20,304**	**19,745**	**19,284**	**18,640**	**19,407**	**19,714**	**18,973**	**18,670**	**17,984**	**16,030**	**15,762**	**15,262**	**14,914**
Aviation Gasoline	374	329	302	291	281	251	260	294	278	263	235	221	225	225	209
Jet Fuel	19,186	17,991	20,002	19,454	19,004	18,389	19,147	19,420	18,695	18,407	17,749	15,809	15,537	15,036	14,705
Commercial Aviation	*11,569*	*12,136*	*14,672*	*13,121*	*12,774*	*12,943*	*13,147*	*13,976*	*14,426*	*14,708*	*13,400*	*12,588*	*11,931*	*12,067*	*11,932*
Ships and Other Boats	**4,507**	**5,789**	**6,431**	**4,416**	**4,834**	**4,089**	**4,300**	**4,881**	**5,143**	**5,746**	**4,950**	**4,379**	**4,910**	**5,084**	**4,510**
Diesel	1,043	1,546	1,750	1,630	1,592	1,711	1,347	1,470	1,409	1,489	1,470	1,480	1,446	1,727	1,475
Gasoline	1,403	1,597	1,653	1,655	1,654	1,648	1,640	1,630	1,620	1,610	1,600	1,591	1,578	1,567	1,557
Residual	2,061	2,646	3,028	1,131	1,588	730	1,313	1,781	2,115	2,647	1,880	1,308	1,886	1,791	1,477
Construction/ Mining Equipment[b]	**4,160**	**4,835**	**5,439**	**5,897**	**6,067**	**6,248**	**6,428**	**6,520**	**6,656**	**6,684**	**6,835**	**6,960**	**7,204**	**7,307**	**7,473**
Diesel	3,674	4,387	5,095	5,241	5,386	5,532	5,678	5,823	5,968	6,113	6,258	6,403	6,547	6,693	6,839
Gasoline	486	448	344	657	681	716	751	697	688	571	577	558	656	614	634
Agricultural Equipment[c]	**3,134**	**3,698**	**3,875**	**4,107**	**4,220**	**4,324**	**4,648**	**4,715**	**4,948**	**4,862**	**4,517**	**4,641**	**4,739**	**4,928**	**5,086**
Diesel	2,321	2,772	3,222	3,305	3,388	3,471	3,554	3,637	3,719	3,801	3,883	3,965	4,046	4,129	4,211
Gasoline	813	927	652	802	832	853	1,094	1,078	1,229	1,061	634	676	692	799	875
Rail	**3,461**	**3,864**	**4,106**	**4,119**	**4,089**	**4,176**	**4,407**	**4,446**	**4,665**	**4,539**	**4,216**	**3,535**	**3,807**	**3,999**	**3,923**
Diesel	3,461	3,864	4,106	4,119	4,089	4,176	4,407	4,446	4,665	4,539	4,216	3,535	3,807	3,999	3,923
Other[d]	**5,916**	**6,525**	**6,826**	**7,657**	**7,840**	**8,049**	**8,263**	**8,281**	**8,396**	**8,256**	**8,387**	**8,482**	**8,830**	**8,795**	**8,730**
Diesel	1,423	1,720	2,016	2,079	2,144	2,210	2,275	2,340	2,405	2,471	2,536	2,601	2,666	2,731	2,797
Gasoline	4,493	4,805	4,810	5,578	5,696	5,840	5,988	5,941	5,991	5,785	5,851	5,881	6,164	6,063	5,933
Total	**40,738**	**43,031**	**46,980**	**45,941**	**46,334**	**45,528**	**47,453**	**48,558**	**48,781**	**48,755**	**46,888**	**44,027**	**45,252**	**45,375**	**44,636**

Sources: AAR (2008 through 2013), APTA (2007 through 2013), BEA (1991 through 2013), Benson (2002 through 2004), DHS (2008), DOC (1991 through 2013), DESC (2013), DOE (1993 through 2013), DOT (1991 through 2013), EIA (2002), EIA (2007b), EIA (2008), EIA (2007 through 2013), EIA (1991 through 2013), EPA (2013b), FAA (2014), Gaffney (2007), and Whorton (2006 through 2012).

[a] For aircraft, this is aviation gasoline. For all other categories, this is motor gasoline.

[b] Includes equipment, such as cranes, dumpers, and excavators, as well as fuel consumption from trucks that are used off-road in construction.

[c] Includes equipment, such as tractors and combines, as well as fuel consumption from trucks that are used off-road in agriculture.

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

Table A-101: Control Technology Assignments for Gasoline Passenger Cars (Percent of VMT)

Model Years	Non-catalyst	Oxidation	EPA Tier 0	EPA Tier 1	LEV	EPA Tier 2
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	-	-	<1%	87%	13%	-
1999	-	-	<1%	67%	33%	-
2000	-	-	-	44%	56%	-
2001	-	-	-	3%	97%	-
2002	-	-	-	1%	99%	-
2003	-	-	-	<1%	87%	13%
2004	-	-	-	<1%	41%	59%
2005	-	-	-	-	38%	62%
2006	-	-	-	-	18%	82%
2007	-	-	-	-	4%	96%
2008	-	-	-	-	2%	98%
2009-12	-	-	-	-	-	100%

Sources: EPA (1998), EPA (2007a), and EPA (2007b).

Note: Detailed descriptions of emissions control technologies are provided in the following section of this annex.

- Not applicable.

Table A-102: Control Technology Assignments for Gasoline Light-Duty Trucks (Percent of VMT)[a]

Model Years	Non-catalyst	Oxidation	EPA Tier 0	EPA Tier 1	LEV[b]	EPA Tier 2
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%	-
2002	-	-	-	10%	90%	-
2003	-	-	-	<1%	53%	47%
2004	-	-	-	-	72%	28%
2005	-	-	-	-	38%	62%
2006	-	-	-	-	25%	75%
2007	-	-	-	-	14%	86%
2008-2012	-	-	-	-	-	100%

Sources: EPA (1998), EPA (2007a), and EPA (2007b).

[a] Detailed descriptions of emissions control technologies are provided in the following section of this annex.

[b] The proportion of LEVs as a whole has decreased since 2001, as carmakers have been able to achieve greater emission reductions with certain types of LEVs, such as ULEVs. Because ULEVs emit about half the emissions of LEVs, a carmaker can reduce the total number of LEVs they need to build to meet a specified emission average for all of their vehicles in a given model year.

- Not applicable.

Table A- 103: Control Technology Assignments for Gasoline Heavy-Duty Vehicles (Percent of VMT)[a]

Model Years	Uncontrolled	Non-catalyst	Oxidation	EPA Tier 0	EPA Tier 1	LEV [b]	EPA Tier 2
≤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%	-
2002	-	-	-	-	69%	31%	-
2003	-	-	-	-	65%	30%	5%
2004	-	-	-	-	5%	37%	59%
2005	-	-	-	-	-	23%	77%
2006	-	-	-	-	-	20%	80%
2007	-	-	-	-	-	10%	90%
2008-2012	-	-	-	-	-	0%	100%

Sources: EPA (1998), EPA (2007a), and EPA (2007b).

[a] Detailed descriptions of emissions control technologies are provided in the following section of this annex.

[b] The proportion of LEVs as a whole has decreased since 2000, as carmakers have been able to achieve greater emission reductions with certain types of LEVs, such as ULEVs. Because ULEVs emit about half the emissions of LEVs, a manufacturer can reduce the total number of LEVs they need to build to meet a specified emission average for all of their vehicles in a given model year.

- Not applicable.

Table A- 104: Control Technology Assignments for Diesel On-Road Vehicles and Motorcycles

Vehicle Type/Control Technology	Model Years
Diesel Passenger Cars and Light-Duty Trucks	
Uncontrolled	1960-1982
Moderate control	1983-1995
Advanced control	1996-2012
Diesel Medium- and Heavy-Duty Trucks and Buses	
Uncontrolled	1960-1990
Moderate control	1991-2003
Advanced control	2004-2006
Aftertreatment	2007-2012
Motorcycles	
Uncontrolled	1960-1995
Non-catalyst controls	1996-2012

Source: EPA (1998) and Browning (2005)

Note: Detailed descriptions of emissions control technologies are provided in the following section of this annex.

Table A- 105: Emission Factors for CH_4 and N_2O for On-Road Vehicles

Vehicle Type/Control Technology	N_2O (g/mi)	CH_4 (g/mi)
Gasoline Passenger Cars		
EPA Tier 2	0.0036	0.0173
Low Emission Vehicles	0.0150	0.0105
EPA Tier 1[a]	0.0429	0.0271
EPA Tier 0 [a]	0.0647	0.0704
Oxidation Catalyst	0.0504	0.1355
Non-Catalyst Control	0.0197	0.1696
Uncontrolled	0.0197	0.1780
Gasoline Light-Duty Trucks		
EPA Tier 2	0.0066	0.0163
Low Emission Vehicles	0.0157	0.0148
EPA Tier 1[a]	0.0871	0.0452
EPA Tier 0[a]	0.1056	0.0776
Oxidation Catalyst	0.0639	0.1516
Non-Catalyst Control	0.0218	0.1908
Uncontrolled	0.0220	0.2024

Gasoline Heavy-Duty Vehicles		
EPA Tier 2	0.0134	0.0333
Low Emission Vehicles	0.0320	0.0303
EPA Tier 1[a]	0.1750	0.0655
EPA Tier 0[a]	0.2135	0.2630
Oxidation Catalyst	0.1317	0.2356
Non-Catalyst Control	0.0473	0.4181
Uncontrolled	0.0497	0.4604
Diesel Passenger Cars		
Advanced	0.0010	0.0005
Moderate	0.0010	0.0005
Uncontrolled	0.0012	0.0006
Diesel Light-Duty Trucks		
Advanced	0.0015	0.0010
Moderate	0.0014	0.0009
Uncontrolled	0.0017	0.0011
Diesel Medium- and Heavy-Duty Trucks and Buses		
Aftertreatment	0.0048	0.0051
Advanced	0.0048	0.0051
Moderate	0.0048	0.0051
Uncontrolled	0.0048	0.0051
Motorcycles		
Non-Catalyst Control	0.0069	0.0672
Uncontrolled	0.0087	0.0899

Source: ICF (2006b and 2004).

[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.

Table A- 106: Emission Factors for CH_4 and N_2O for Alternative Fuel Vehicles (g/mi)

	N_2O	CH_4
Light Duty Vehicles		
Methanol	0.067	0.018
CNG	0.050	0.737
LPG	0.067	0.037
Ethanol	0.067	0.055
Biodiesel (BD20)	0.001	0.0005
Medium- and Heavy-Duty Trucks		
Methanol	0.175	0.066
CNG	0.175	1.966
LNG	0.175	1.966
LPG	0.175	0.066
Ethanol	0.175	0.197
Biodiesel (BD20)	0.005	0.005
Buses		
Methanol	0.175	0.066
CNG	0.175	1.966
Ethanol	0.175	0.197
Biodiesel (BD20)	0.005	0.005

Source: Developed by ICF (2006a) using ANL (2006) and Lipman and Delucchi (2002).

Table A- 107: Emission Factors for CH_4 and N_2O Emissions from Non-Road Mobile Combustion (g/kg fuel)

Vehicle Type/Fuel Type	N_2O	CH_4
Ships and Boats		
Residual	0.16	0.03
Gasoline	0.08	0.23
Diesel	0.14	0.02
Rail		
Diesel	0.08	0.25
Agricultural Equipment[a]		
Gasoline	0.08	0.45
Diesel	0.08	0.45
Construction/Mining Equipment[c]		
Gasoline	0.08	0.18

Diesel	0.08	0.18
Other Non-Road		
All “Other” Categories[c]	0.08	0.18
Aircraft		
Jet Fuel	0.10	0.00
Aviation Gasoline	0.04	2.64

Source: IPCC/UNEP/OECD/IEA (1997) and ICF (2009).

[a] Includes equipment, such as tractors and combines, as well as fuel consumption from trucks that are used off-road in agriculture.

[b] Includes equipment, such as cranes, dumpers, and excavators, as well as fuel consumption from trucks that are used off-road in construction.

[c] “Other" includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment, as well as fuel consumption from trucks that are used off-road for commercial/industrial purposes.

[d] Emissions of CH_4 from jet fuels have been zeroed out across the time series. Recent research indicates that modern aircraft jet engines are typically net consumers of methane (Santoni et al, 2011). Methane is emitted at low power and idle operation, but at higher power modes aircraft engines consumer methane. Over the range of engine operating modes, aircraft engines are net consumers of methane on average. Based on this data, methane emissions factors for jet aircraft were changed to zero in this year’s Inventory to reflect the latest emissions testing data.

Table A- 108: NO_x Emissions from Mobile Combustion (Gg)

Fuel Type/Vehicle Type	1990	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Gasoline On-Road	**5,746**	**4,560**	**3,812**	**3,715**	**4,917**	**4,600**	**4,284**	**3,967**	**3,800**	**3,633**	**3,295**	**2,962**	**2,722**	**2,749**	**2,564**
Passenger Cars	3,847	2,752	2,084	2,027	2,683	2,510	2,337	2,164	2,073	1,982	1,798	1,616	1,485	1,500	1,399
Light-Duty Trucks	1,364	1,325	1,303	1,285	1,700	1,591	1,481	1,372	1,314	1,257	1,139	1,024	941	951	887
Medium- and Heavy-Duty Trucks and Buses	515	469	411	390	516	483	450	416	399	381	346	311	286	288	269
Motorcycles	20	14	13	14	18	17	16	15	14	13	12	11	10	10	9
Diesel On-Road	**2,956**	**3,493**	**3,803**	**3,338**	**4,418**	**4,134**	**3,849**	**3,564**	**3,414**	**3,265**	**2,960**	**2,661**	**2,446**	**2,470**	**2,303**
Passenger Cars	39	19	7	6	8	7	7	6	6	6	5	5	4	4	4
Light-Duty Trucks	20	12	6	5	7	7	6	6	6	5	5	4	4	4	4
Medium- and Heavy-Duty Trucks and Buses	2,897	3,462	3,791	3,326	4,403	4,119	3,836	3,552	3,403	3,254	2,950	2,652	2,438	2,461	2,295
Alternative Fuel On-Road[a]	**IE**	**IE**	**IE**	**IE**	**IE**	**IE**	**IE**	**IE**	**IE**	**IE**	**IE**	**IE**	**IE**	**IE**	**IE**
Non-Road	**2,160**	**2,483**	**2,584**	**2,643**	**3,095**	**2,969**	**2,844**	**2,719**	**2,479**	**2,240**	**2,225**	**2,186**	**2,139**	**1,995**	**1,865**
Ships and Boats	402	488	506	544	640	614	588	562	513	463	460	452	443	413	386
Rail	338	433	451	485	571	548	525	502	458	414	411	403	395	368	344
Aircraft[b]	25	31	40	39	46	44	43	41	37	33	33	33	32	30	28
Agricultural Equipment[c]	437	478	484	480	560	537	514	492	448	405	402	395	387	361	337
Construction/Mining Equipment[d]	641	697	697	690	804	771	739	706	644	582	578	568	556	518	484
Other[e]	318	357	407	406	474	454	435	416	379	343	341	335	327	305	285
Total	**10,862**	**10,536**	**10,199**	**9,696**	**12,430**	**11,703**	**10,977**	**10,250**	**9,694**	**9,138**	**8,481**	**7,809**	**7,307**	**7,214**	**6,732**

[a] NO_x emissions from alternative fuel on-road vehicles are included under gasoline and diesel on-road.

[b] Aircraft estimates include only emissions related to LTO cycles, and therefore do not include cruise altitude emissions.

[c] Includes equipment, such as tractors and combines, as well as fuel consumption from trucks that are used off-road in agriculture.

[d] Includes equipment, such as cranes, dumpers, and excavators, as well as fuel consumption from trucks that are used off-road in construction.

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

Note: Totals may not sum due to independent rounding.

IE = Included Elsewhere

Table A- 109: CO Emissions from Mobile Combustion (Gg)

Fuel Type/Vehicle Type	1990	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012[f]
Gasoline On-Road	**98,328**	**74,673**	**60,657**	**56,716**	**45,690**	**43,102**	**40,513**	**37,925**	**35,485**	**33,046**	**29,418**	**24,554**	**25,294**	**23,793**	**23,793**
Passenger Cars	60,757	42,065	32,867	31,600	25,456	24,014	22,572	21,130	19,771	18,412	16,390	13,680	14,093	13,256	13,256
Light-Duty Trucks	29,237	27,048	24,532	22,574	18,186	17,155	16,125	15,095	14,124	13,153	11,709	9,773	10,068	9,470	9,470
Medium- and Heavy-Duty Trucks and Buses	8,093	5,404	3,104	2,411	1,942	1,832	1,722	1,612	1,509	1,405	1,251	1,044	1,075	1,011	1,011
Motorcycles	240	155	154	131	106	100	94	88	82	77	68	57	59	55	55
Diesel On-Road	**1,696**	**1,424**	**1,088**	**869**	**700**	**661**	**621**	**581**	**544**	**506**	**451**	**376**	**388**	**365**	**365**
Passenger Cars	35	18	7	6	5	4	4	4	4	3	3	3	3	2	2
Light-Duty Trucks	22	16	6	5	4	4	4	4	3	3	3	2	2	2	2
Medium- and Heavy-Duty Trucks and Buses	1,639	1,391	1,075	858	691	652	613	574	537	500	445	371	383	360	360
Alternative Fuel On-Road[a]	**IE**	**IE**	**IE**	**IE**	**IE**	**IE**	**IE**	**IE**	**IE**	**IE**	**IE**	**IE**	**IE**	**IE**	**IE**
Non-Road	**19,337**	**21,533**	**21,814**	**22,266**	**20,187**	**19,976**	**19,766**	**19,556**	**18,181**	**16,807**	**16,134**	**14,290**	**13,786**	**13,329**	**13,329**
Ships and Boats	1,559	1,781	1,825	1,831	1,660	1,643	1,626	1,609	1,496	1,382	1,327	1,175	1,134	1,096	1,096
Rail	85	93	90	90	81	81	80	79	73	68	65	58	56	54	54
Aircraft[b]	217	224	245	233	212	209	207	205	191	176	169	150	145	140	140
Agricultural Equipment[c]	581	628	626	621	563	557	551	546	507	469	450	399	385	372	372

Construction/Mining Equipment[d]	1,090	1,132	1,047	1,041	944	934	924	914	850	786	754	668	645	623	623
Other[e]	15,805	17,676	17,981	18,449	16,726	16,552	16,377	16,203	15,064	13,926	13,368	11,840	11,423	11,044	11,044
Total	**119,360**	**97,630**	**83,559**	**79,851**	**66,577**	**63,739**	**60,900**	**58,062**	**54,211**	**50,359**	**46,003**	**39,219**	**39,468**	**37,486**	**37,486**

[a] NO_x emissions from alternative fuel on-road vehicles are included under gasoline and diesel on-road.

[b] Aircraft estimates include only emissions related to LTO cycles, and therefore do not include cruise altitude emissions.

[c] Includes equipment, such as tractors and combines, as well as fuel consumption from trucks that are used off-road in agriculture.

[d] Includes equipment, such as cranes, dumpers, and excavators, as well as fuel consumption from trucks that are used off-road in construction.

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

[f] Criteria Air Pollutant emissions for 2012 were unavailable. Values from 2011 are used as proxy estimates.

Note: Totals may not sum due to independent rounding.

IE = Included Elsewhere

Table A- 110: NMVOCs Emissions from Mobile Combustion (Gg)

Fuel Type/Vehicle Type	1990	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Gasoline On-Road	**8,110**	**5,819**	**4,615**	**4,285**	**3,437**	**3,274**	**3,111**	**2,948**	**2,970**	**2,993**	**2,623**	**2,383**	**2,393**	**2,076**	**1,967**
Passenger Cars	5,120	**3,394**	2,610	2,393	1,919	1,828	1,737	1,646	1,659	1,671	1,465	1,331	1,336	1,159	1,098
Light-Duty Trucks	2,374	**2,019**	1,750	1,664	1,335	1,271	1,208	1,145	1,153	1,162	1,019	926	929	806	764
Medium- and Heavy-Duty Trucks and Buses	575	**382**	232	206	165	157	150	142	143	144	126	115	115	100	95
Motorcycles	42	**24**	23	22	18	17	16	15	15	15	13	12	12	11	10
Diesel On-Road	**406**	**304**	**216**	**207**	**166**	**158**	**151**	**143**	**144**	**145**	**127**	**115**	**116**	**100**	**95**
Passenger Cars	16	**8**	3	3	2	2	2	2	2	2	2	2	2	1	1
Light-Duty Trucks	14	**9**	4	4	3	3	3	3	3	3	2	2	2	2	2
Medium- and Heavy-Duty Trucks and Buses	377	**286**	209	201	161	153	146	138	139	140	123	112	112	97	92
Alternative Fuel On-Road[a]	**IE**	**IE**	**IE**	**IE**	**IE**	**IE**	**IE**	**IE**	**IE**	**IE**	**IE**	**IE**	**IE**	**IE**	**IE**
Non-Road	**2,415**	**2,622**	**2,398**	**2,379**	**2,774**	**2,708**	**2,642**	**2,576**	**2,469**	**2,361**	**2,309**	**2,153**	**2,087**	**1,941**	**1,863**
Ships and Boats	608	**739**	744	730	851	831	811	791	757	724	708	661	640	596	572
Rail	33	**36**	35	35	41	40	39	38	37	35	34	32	31	29	28
Aircraft[b]	28	**28**	24	19	22	22	21	21	20	19	19	17	17	16	15
Agricultural Equipment[c]	85	**86**	76	72	84	82	80	78	75	72	70	66	64	59	57
Construction/Mining Equipment[d]	149	**152**	130	125	146	142	139	135	130	124	121	113	110	102	98
Other[e]	1,512	**1,580**	1,390	1,397	1,629	1,590	1,552	1,513	1,450	1,387	1,356	1,264	1,225	1,140	1,094
Total	**10,932**	**8,745**	**7,230**	**6,872**	**6,377**	**6,140**	**5,903**	**5,667**	**5,583**	**5,498**	**5,059**	**4,652**	**4,596**	**4,118**	**3,925**

[a] NO_x emissions from alternative fuel on-road vehicles are included under gasoline and diesel on-road.

[b] Aircraft estimates include only emissions related to LTO cycles, and therefore do not include cruise altitude emissions.

[c] Includes equipment, such as tractors and combines, as well as fuel consumption from trucks that are used off-road in agriculture.

[d] Includes equipment, such as cranes, dumpers, and excavators, as well as fuel consumption from trucks that are used off-road in construction.

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

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

IE = Included Elsewhere

Definitions of Emission Control Technologies and Standards

The N_2O and CH_4 emission factors used depend on the emission standards in place and the corresponding level of control technology for each vehicle type. Table A- 101 through Table A- 104 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 and were compiled from EPA (1993, 1994a, 1994b, 1998, 1999a) and IPCC/UNEP/OECD/IEA (1997).

Uncontrolled

Vehicles manufactured prior to the implementation of pollution control technologies are designated as uncontrolled. Gasoline passenger cars and light-duty trucks (pre-1973), gasoline heavy-duty vehicles (pre-1984), diesel vehicles (pre-1983), and motorcycles (pre-1996) are assumed to have no 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.

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 1997. The two-way catalytic converter oxidizes HC and CO, significantly reducing emissions over 80 percent beyond non-catalyst-system capacity. One reason unleaded gasoline was introduced in 1975 was due to the fact that oxidation catalysts cannot function properly with leaded gasoline.

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 CO_2 and H_2O, reducing NO_x to nitrogen and oxygen, and using an on-board diagnostic computer and oxygen sensor. In addition, this type of catalyst includes a fuel metering system (carburetor or fuel injection) with electronic "trim" (also known as a "closed-loop system"). 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 limited passenger car NO_x emissions to 0.4 g/mi, and HC emissions to 0.25 g/mi. These bounds respectively amounted to a 60 and 40 percent reduction from the EPA Tier 0 standard set in 1981. For light-duty trucks, this standard set emissions at 0.4 to 1.1 g/mi for NO_x, and 0.25 to 0.39 g/mi for HCs, depending on the weight of the truck. Emission reductions were met through the use of more advanced emission control systems, and applied to light-duty gasoline vehicles beginning in 1994. These advanced emission control systems included advanced three-way catalysts, electronically controlled fuel injection and ignition timing, EGR, and air injection.

EPA Tier 2

This emission standard was specified in the 1990 amendments to the Clean Air Act, limiting passenger car NO_x emissions to 0.07 g/mi on average and aligning emissions standards for passenger cars and light-duty trucks. Manufacturers can meet this average emission level by producing vehicles in 11 emission “Bins”, the three highest of which expire in 2006. These new emission levels represent a 77 to 95 percent reduction in emissions from the EPA Tier 1 standard set in 1994. Emission reductions were met through the use of more advanced emission control systems and lower sulfur fuels and are applied to vehicles beginning in 2004. These advanced emission control systems include improved combustion, advanced three-way catalysts, electronically controlled fuel injection and ignition timing, EGR, and air injection.

Low Emission Vehicles (LEV)

This emission standard requires a much higher emission control level than the Tier 1 standard. Applied to light-duty gasoline passenger cars and trucks beginning in small numbers in the mid-1990s, LEV includes multi-port fuel injection with adaptive learning, an advanced computer diagnostics systems and advanced and close coupled catalysts with secondary air injection. LEVs as defined here include transitional low-emission vehicles (TLEVs), low emission vehicles, ultra-low emission vehicles (ULEVs) and super ultra-low emission vehicles (SULEVs). In this analysis, all categories of LEVs are treated the same due to the fact that there are very limited CH_4 or N_2O 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 three 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. 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 level of emission control necessary to comply with standards in place from 1996 through 2006.

Aftertreatment

Use of diesel particulate filters (DPFs), oxidation catalysts and NO_x absorbers or selective catalytic reduction (SCR) systems are designated as aftertreatment control. These technologies provide diesel vehicles with a level of emission control necessary to comply with standards in place from 2007 on.

Supplemental Information on GHG Emissions from Transportation and Other Mobile Sources

This section of this Annex includes supplemental information on the contribution of transportation and other mobile sources to U.S. greenhouse gas emissions. In the main body of the Inventory report, emission estimates are generally presented by greenhouse gas, with separate discussions of the methodologies used to estimate CO_2, N_2O, CH_4, and HFC emissions. Although the inventory is not required to provide detail beyond what is contained in the body of this report, the IPCC allows presentation of additional data and detail on emission sources. The purpose of this sub-annex, within the annex that details the calculation methods and data used for non-CO_2 calculations, is to provide all transportation estimates presented throughout the report in one place.

This section of this Annex reports total greenhouse gas emissions from transportation and other (non-transportation) mobile sources in CO_2 equivalents, with information on the contribution by greenhouse gas and by mode, vehicle type, and fuel type. In order to calculate these figures, additional analyses were conducted to develop estimates of CO_2 from non-transportation mobile sources (e.g., agricultural equipment, construction/mining equipment, recreational vehicles), and to provide more detailed breakdowns of emissions by source.

Estimation of CO_2 from Non-Transportation Mobile Sources

The estimates of N_2O and CH_4 from fuel combustion presented in the Energy chapter of the inventory include both transportation sources and other mobile sources. Other mobile sources include construction/mining equipment, agricultural equipment, vehicles used off-road, and other sources that have utility associated with their movement but do not have a primary purpose of transporting people or goods (e.g., snowmobiles, riding lawnmowers, etc.). Estimates of CO_2 from non-transportation mobile sources, based on EIA fuel consumption estimates, are included in the agricultural, industrial, and commercial sectors. In order to provide comparable information on transportation and mobile sources, Table A- 111 provides estimates of CO_2 from these other mobile sources, developed from EPA's NONROAD model and FHWA's *Highway Statistics*. These other mobile source estimates were developed using the same fuel consumption data utilized in developing the N_2O and CH_4 estimates.

Table A- 111: CO_2 Emissions from Non-Transportation Mobile Sources (Tg CO_2 Eq.)

Fuel Type/Vehicle Type	1990	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Agricultural Equipment[a]	31.0	36.6	38.8	41.0	42.1	43.1	46.1	46.8	49.0	48.4	45.4	46.7	47.6	49.4	51.0
Construction/Mining Equipment[b]	42.0	48.9	55.3	59.5	61.2	63.0	64.9	65.9	67.3	67.8	69.3	70.6	73.0	74.1	75.8
Other Sources[c]	54.5	59.8	62.8	70.2	72.0	73.9	76.0	76.2	77.6	76.7	77.7	78.6	81.8	81.6	81.1
Total	**127.6**	**145.4**	**156.9**	**170.7**	**175.3**	**180.0**	**187.0**	**188.9**	**193.9**	**193.0**	**192.4**	**195.9**	**202.4**	**205.1**	**207.8**

[a] Includes equipment, such as tractors and combines, as well as fuel consumption from trucks that are used off-road in agriculture.

[b] Includes equipment, such as cranes, dumpers, and excavators, as well as fuel consumption from trucks that are used off-road in construction.

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

Estimation of HFC Emissions from Transportation Sources

In addition to CO_2, N_2O and CH_4 emissions, transportation sources also result in emissions of HFCs. HFCs are emitted to the atmosphere during equipment manufacture and operation (as a result of component failure, leaks, and purges), as well as at servicing and disposal events. There are three categories of transportation-related HFC emissions; Mobile AC represents the emissions from air conditioning units in passenger cars and light-duty trucks, Comfort Cooling represents the emissions from air conditioning units in passenger trains and buses, and Refrigerated Transport represents the emissions from units used to cool freight during transportation.

Table A- 112 below presents these HFC emissions. Table A- 113 presents all transportation and mobile source greenhouse gas emissions, including HFC emissions.

Table A- 112: HFC Emissions from Transportation Sources

Vehicle Type	1990	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Mobile AC	**-**	**17.2**	**48.7**	**53.7**	**56.9**	**59.4**	**62.0**	**64.3**	**66.3**	**68.0**	**69.4**	**69.2**	**66.9**	**62.5**	**58.5**
Passenger Cars	-	10.1	25.6	27.9	29.3	30.0	30.8	31.4	32.2	32.6	32.9	32.1	30.4	27.6	25.2
Light-Duty Trucks	-	7.1	23.1	25.8	27.6	29.4	31.2	32.8	34.2	35.4	36.4	37.0	36.5	34.9	33.3
Comfort Cooling for Trains and Buses	**-**	**+**	**0.1**	**0.2**	**0.2**	**0.2**	**0.2**	**0.3**	**0.3**	**0.3**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**
School and Tour Buses	-	+	0.1	0.1	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.4	0.4	0.4	0.4
Transit Buses	-	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Rail	-	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Refrigerated Transport	**-**	**2.3**	**9.6**	**10.5**	**11.2**	**12.0**	**12.8**	**13.2**	**13.6**	**13.8**	**13.8**	**13.9**	**13.9**	**14.0**	**14.0**
Medium- and Heavy-Duty Trucks	-	1.7	7.4	8.1	8.7	10.0	10.7	11.1	11.4	11.5	11.6	11.6	11.6	11.7	11.7
Rail	-	0.5	2.0	2.2	2.4	1.9	2.1	2.1	2.2	2.2	2.2	2.2	2.3	2.3	2.3
Ships and Other Boats	-	+	0.1	0.1	0.2	+	+	+	+	+	+	+	+	+	+
Total	**-**	**19.6**	**58.4**	**64.3**	**68.3**	**71.6**	**75.0**	**77.8**	**80.2**	**82.1**	**83.6**	**83.5**	**81.3**	**76.9**	**72.9**

Note: Totals may not sum due to independent rounding.

+ Less than 0.05 Tg CO_2 Eq.

- Unreported or zero

Contribution of Transportation and Mobile Sources to Greenhouse Gas Emissions, by Mode/Vehicle Type/Fuel Type

Table A- 113 presents estimates of greenhouse gas emissions from an expanded analysis including all transportation and additional mobile sources, as well as emissions from electricity generation by the consuming category, in CO_2 equivalents. In total, transportation and non-transportation mobile sources emitted 2,050.7 Tg CO_2 Eq. in 2012, an increase of 22 percent from 1990. Transportation sources account for 1,841.0 Tg CO_2 Eq. while non-transportation mobile sources account for 209.8 Tg CO_2 Eq. These estimates include HFC emissions for mobile AC, comfort cooling for trains and buses, and refrigerated transport. These estimates were generated using the estimates of CO_2 emissions from transportation sources reported in the Carbon Dioxide Emissions from Fossil Fuel Combustion section, and CH_4 emissions and N_2O emissions reported in the Mobile Combustion section of the Energy chapter; information on HFCs from mobile air conditioners, comfort cooling for trains and buses, and refrigerated transportation from Chapter 4; and estimates of CO_2 emitted from non-transportation mobile sources reported in Table A- 109 above.

Although all emissions reported here are based on estimates reported throughout this inventory, some additional calculations were performed in order to provide a detailed breakdown of emissions by mode and vehicle category. In the case of N_2O and CH_4, additional calculations were performed to develop emissions estimates by type of aircraft and type of heavy-duty vehicle (i.e., medium- and heavy-duty trucks or buses) to match the level of detail for CO_2 emissions. N_2O estimates for jet fuel and aviation gasoline and CH_4 estimates for aviation gasoline were developed for individual aircraft types by multiplying the emissions estimates for aircraft for each fuel type (jet fuel and aviation gasoline) by the portion of fuel used by each aircraft type (from FAA 2014). Emissions of CH_4 from jet fuels are no longer considered to be emitted across the time series from aircraft gas turbine engines burning jet fuel A at higher power settings.[54] Recent research indicates that modern aircraft jet engines are typically net consumers of methane (Santoni et al, 2011). Methane is emitted at low power and idle operation, but at higher power modes aircraft engines consumer methane. Over the range of engine operating modes, aircraft engines are net consumers of methane on average. Based on this data, methane emissions factors for jet aircraft were reported as zero to reflect the latest emissions testing data.

Similarly, N_2O and CH_4 estimates were developed for medium- and heavy-duty trucks and buses by multiplying the emission estimates for heavy-duty vehicles for each fuel type (gasoline, diesel) from the Mobile Combustion section in the Energy chapter, by the portion of fuel used by each vehicle type (from DOE 1993 through 2013). Otherwise, the table and figure are drawn directly from emission estimates presented elsewhere in the inventory, and are dependent on the methodologies presented in Annex 2.1 (for CO_2), Chapter 4, and Annex 3.8 (for HFCs), and earlier in this Annex (for CH_4 and N_2O).

Transportation sources include on-road vehicles, aircraft, boats and ships, rail, and pipelines (note: pipelines are a transportation source but are stationary, not mobile sources). In addition, transportation-related greenhouse gas emissions also include HFC released from mobile air conditioners and refrigerated transportation, and the release of CO_2 from lubricants (such as motor oil) used in transportation. Together, transportation sources were responsible for 1,841.0 Tg CO_2 Eq. in 2012.

On-road vehicles were responsible for about 76 percent of all transportation and non-transportation mobile GHG emissions in 2012. Although passenger cars make up the largest component of on-road vehicle greenhouse gas emissions, light-duty and medium- and heavy-duty trucks have been the primary sources of growth in on-road vehicle emissions. Between 1990 and 2012, greenhouse gas emissions from passenger cars increased by 21 percent, while emissions from light-duty trucks increased by one percent. [55] Meanwhile, greenhouse gas emissions from medium- and heavy-duty trucks increased 75 percent between 1990 and 2012, reflecting the increased volume of total freight movement and an increasing share transported by trucks.

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[54] Recommended Best Practice for Quantifying Speciated Organic Gas Emissions from Aircraft Equipped with Turbofan, Turbojet and Turboprop Engines," EPA-420-R-09-901, May 27, 2009 (see http://www.epa.gov/otaq/regs/nonroad/aviation/420r09901.pdf>

[55] In 2011 FHWA changed how they defined vehicle types for the purposes of reporting VMT for the years 2007-2010. The old approach to vehicle classification was based on body type and split passenger vehicles into "Passenger Cars" and "Other 2 Axle 4-Tire Vehicles". The new approach is a vehicle classification system based on wheelbase. Vehicles with a wheelbase less than or equal to 121 inches are counted as "Light-duty Vehicles –Short Wheelbase". Passenger vehicles with a Wheelbase greater than 121 inches are counted as "Light-duty Vehicles - Long Wheelbase". This change in vehicle classification has moved some smaller trucks and sport utility vehicles from the light truck category to the passenger vehicle category in this emission inventory. These changes are reflected in a large drop in light-truck emissions between 2006 and 2007.

Greenhouse gas emissions from aircraft decreased 23 percent between 1990 and 2012. Emissions from military aircraft decreased 65 percent between 1990 and 2012. Commercial aircraft emissions rose 27 percent between 1990 and 2007 then dropped 19 percent from 2007 to 2012, a change of approximately 3.1 percent between 1990 and 2012.

Non-transportation mobile sources, such as construction/mining equipment, agricultural equipment, and industrial/commercial equipment, emitted approximately 209.8 Tg CO_2 Eq. in 2012. Together, these sources emitted more greenhouse gases than ships and boats, and rail combined. Emissions from non-transportation mobile sources increased rapidly, growing approximately 63 percent between 1990 and 2012. CH_4 and N_2O emissions from these sources are included in the “Mobile Combustion” section and CO_2 emissions are included in the relevant economic sectors.

Contribution of Transportation and Mobile Sources to Greenhouse Gas Emissions, by Gas

Table A- 114 presents estimates of greenhouse gas emissions from transportation and other mobile sources broken down by greenhouse gas. As this table shows, CO_2 accounts for the vast majority of transportation greenhouse gas emissions (approximately 96 percent in 2012). Emissions of CO_2 from transportation and mobile sources increased by 323.1 Tg CO_2 Eq. between 1990 and 2012. In contrast, the combined emissions of CH_4 and N_2O decreased by 30.4 Tg CO_2 Eq. over the same period, due largely to the introduction of control technologies designed to reduce criteria pollutant emissions.[56] Meanwhile, HFC emissions from mobile air conditioners and refrigerated transport increased from virtually no emissions in 1990 to 72.9 Tg CO_2 Eq. in 2012 as these chemicals were phased in as substitutes for ozone depleting substances. It should be noted, however, that the ozone depleting substances that HFCs replaced are also powerful greenhouse gases, but are not included in national greenhouse gas inventories due to their mandated phase out.

Greenhouse Gas Emissions from Freight and Passenger Transportation

Table A- 115 and Table A- 116 present greenhouse gas estimates from transportation, broken down into the passenger and freight categories. Passenger modes include light-duty vehicles, buses, passenger rail, aircraft (general aviation and commercial aircraft), recreational boats, and mobile air conditioners, and are illustrated in Table A- 115. Freight modes include medium- and heavy-duty trucks, freight rail, refrigerated transport, waterborne freight vessels, pipelines, and commercial aircraft and are illustrated in Table A- 116. Commercial aircraft do carry some freight, in addition to passengers, and for this Inventory, the emissions have been split between passenger and freight transportation. (In previous Inventories, all commercial aircraft emissions were considered passenger transportation.) The amount of commercial aircraft emissions to allocate to the passenger and freight categories was calculated using BTS data on freight shipped by commercial aircraft, and the total number of passengers enplaned. Each passenger was considered to weigh an average of 150 pounds, with a luggage weight of 50 pounds. The total freight weight and total passenger weight carried were used to determine percent shares which were used to split the total commercial aircraft emissions estimates. The remaining transportation and mobile emissions were from sources not considered to be either freight or passenger modes (e.g., construction/mining and agricultural equipment, lubricants).

The estimates in these tables are derived from the estimates presented in Table A- 113. In addition, estimates of fuel consumption from DOE (1993 through 2013) were used to allocate rail emissions between passenger and freight categories.

In 2012, passenger transportation modes emitted 1,296.0Tg CO_2 Eq., while freight transportation modes emitted 524.5 Tg CO_2 Eq. Between 1990 and 2012, the percentage growth of greenhouse gas emissions from freight sources was 49 percent, while emissions from passenger sources grew by 12 percent. This difference in growth is due largely to the rapid increase in emissions associated with medium- and heavy-duty trucks.

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[56] The decline in CFC emissions is not captured in the official transportation estimates.

Table A- 113: Total U.S. Greenhouse Gas Emissions from Transportation and Mobile Sources (Tg CO_2 Eq.)

Mode / Vehicle Type / Fuel Type	1990	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Percent Change 1990-2012
Transportation Total[a]	**1,556.3**	**1700.4**	**1933.6**	**1920.2**	**1961.0**	**1953.7**	**2002.0**	**2022.0**	**2019.8**	**2031.5**	**1939.9**	**1866.9**	**1880.9**	**1856.4**	**1841.0**	**18%**
On-Road Vehicles	**1,235.2**	**1371.9**	**1577.8**	**1589.5**	**1628.4**	**1641.1**	**1677.5**	**1687.7**	**1687.7**	**1694.1**	**1621.6**	**1581.4**	**1587.9**	**1564.6**	**1558.4**	**26%**
Passenger Cars	**657.4**	**646.0**	**696.6**	**703.2**	**716.9**	**695.6**	**693.1**	**712.6**	**688.0**	**855.4**	**817.9**	**811.5**	**805.8**	**798.0**	**793.8**	**21%**
Gasoline	649.4	627.9	667.3	671.6	683.9	661.3	658.0	676.9	651.6	818.6	781.2	775.7	771.7	766.2	764.4	18%
Diesel	7.9	7.9	3.7	3.7	3.7	4.2	4.3	4.2	4.1	4.1	3.7	3.6	3.8	4.1	4.2	-47%
AFVs	+	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	421%
HFCs from Mobile AC	+	10.1	25.6	27.9	29.3	30.0	30.8	31.4	32.2	32.6	32.9	32.1	30.4	27.6	25.2	NA
Light-Duty Trucks	**336.6**	**437.1**	**513.5**	**520.4**	**531.6**	**567.1**	**589.9**	**553.1**	**566.9**	**371.7**	**354.8**	**359.9**	**359.1**	**343.1**	**338.4**	**1%**
Gasoline	324.5	414.6	469.8	473.2	481.4	509.7	528.9	493.0	504.7	321.7	304.4	309.5	308.6	293.5	290.3	-11%
Diesel	11.5	14.9	20.1	20.8	21.9	27.2	29.0	25.9	26.8	13.6	12.1	12.1	12.6	13.2	13.2	15%
AFVs	0.6	0.5	0.5	0.6	0.7	0.8	0.9	1.3	1.2	1.0	1.8	1.2	1.3	1.5	1.5	164%
HFCs from Mobile AC	+	7.1	23.1	25.8	27.6	29.4	31.2	32.8	34.2	35.4	36.4	37.0	36.5	34.9	33.3	NA
Medium- and Heavy-Duty Trucks	**231.1**	**277.8**	**354.6**	**353.8**	**368.1**	**365.9**	**377.7**	**408.4**	**418.6**	**444.7**	**427.0**	**389.2**	**402.9**	**402.4**	**403.4**	**75%**
Gasoline	39.5	36.8	37.0	36.1	36.5	31.6	31.9	35.8	36.3	47.6	48.1	44.3	44.2	40.7	40.3	2%
Diesel	190.7	238.6	309.9	309.3	322.6	323.8	334.7	361.0	370.4	385.0	366.5	332.6	346.3	349.3	350.6	84%
AFVs	0.9	0.6	0.3	0.4	0.4	0.5	0.4	0.5	0.6	0.5	0.8	0.7	0.7	0.8	0.8	-12%
HFCs from Refrigerated Transport	+	1.7	7.4	8.1	8.7	10.0	10.7	11.1	11.4	11.5	11.6	11.6	11.6	11.7	11.7	NA
Buses	**8.4**	**9.2**	**11.2**	**10.3**	**10.0**	**10.8**	**15.0**	**12.1**	**12.3**	**18.0**	**17.4**	**16.5**	**16.3**	**17.5**	**18.6**	**122%**
Gasoline	0.4	0.4	0.4	0.4	0.3	0.3	0.5	0.4	0.4	0.7	0.8	0.8	0.8	0.8	0.8	131%
Diesel	8.0	8.7	10.2	9.3	8.8	9.5	13.5	10.6	10.8	15.9	15.2	14.1	14.1	15.2	16.3	103%
AFVs	+	0.1	0.5	0.5	0.6	0.7	0.9	0.9	0.8	1.0	1.1	1.2	1.1	1.1	1.1	40484%
HFCs from Comfort Cooling	+	0.0	0.1	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.4	0.4	0.4	0.4	0.4	NA
Motorcycles	**1.8**	**1.8**	**1.9**	**1.7**	**1.7**	**1.7**	**1.8**	**1.7**	**1.9**	**4.3**	**4.5**	**4.3**	**3.8**	**3.7**	**4.3**	**141%**
Gasoline	1.8	1.8	1.9	1.7	1.7	1.7	1.8	1.7	1.9	4.3	4.5	4.3	3.8	3.7	4.3	141%
Aircraft	**189.2**	**176.7**	**199.4**	**194.0**	**189.4**	**183.1**	**190.7**	**193.7**	**186.4**	**183.4**	**176.7**	**157.5**	**154.8**	**149.9**	**146.5**	**-23%**
General Aviation Aircraft	**43.0**	**35.8**	**35.9**	**43.7**	**45.1**	**36.9**	**41.9**	**40.1**	**30.1**	**24.4**	**30.5**	**21.2**	**26.7**	**22.5**	**19.9**	**-54%**
Jet Fuel	39.8	33.0	33.4	41.2	42.7	34.7	39.7	37.6	27.7	22.2	28.5	19.4	24.8	20.6	18.2	-54%
Aviation Gasoline	3.2	2.8	2.6	2.5	2.4	2.1	2.2	2.5	2.4	2.2	2.0	1.9	1.9	1.9	1.8	-44%
Commercial Aircraft	**110.9**	**116.4**	**140.7**	**125.8**	**122.5**	**124.1**	**126.0**	**134.0**	**138.3**	**141.0**	**128.5**	**120.7**	**114.4**	**115.7**	**114.4**	**3%**
Jet Fuel	110.9	116.4	140.7	125.8	122.5	124.1	126.0	134.0	138.3	141.0	128.5	120.7	114.4	115.7	114.4	3%
Military Aircraft	**35.3**	**24.5**	**22.9**	**24.5**	**21.9**	**22.2**	**22.7**	**19.5**	**18.0**	**18.0**	**17.7**	**15.6**	**13.7**	**11.7**	**12.2**	**-65%**
Jet Fuel	35.3	24.5	22.9	24.5	21.9	22.2	22.7	19.5	18.0	18.0	17.7	15.6	13.7	11.7	12.2	-65%
Ships and Boats[b]	**45.1**	**58.6**	**61.0**	**42.7**	**47.6**	**37.3**	**40.1**	**45.2**	**48.4**	**55.2**	**45.9**	**39.3**	**45.3**	**47.0**	**40.8**	**-10%**
Gasoline	12.6	14.1	10.0	14.6	14.6	14.4	14.4	14.2	14.1	14.0	13.6	13.5	13.3	13.1	13.1	4%
Distillate Fuel	9.6	14.9	17.1	15.8	15.4	15.3	11.5	11.4	10.9	11.7	11.5	11.6	11.3	14.2	11.6	20%
Residual Fuel	22.9	29.5	33.8	12.2	17.4	7.6	14.2	19.6	23.4	29.5	20.7	14.2	20.8	19.7	16.1	-30%
HFCs from Refrigerated Transport	+	0.0	0.1	0.1	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	NA
Rail	**39.0**	**43.7**	**48.1**	**48.6**	**48.2**	**49.5**	**52.3**	**53.0**	**55.1**	**54.4**	**50.7**	**43.4**	**46.3**	**48.0**	**46.9**	**20%**
Distillate Fuel	35.8	40.0	42.5	42.6	42.3	43.2	45.6	46.0	48.3	47.0	43.6	36.6	39.4	41.4	40.6	13%
Electricity	3.1	3.1	3.5	3.7	3.5	4.3	4.6	4.8	4.6	5.1	4.7	4.5	4.5	4.3	3.9	27%

Other Emissions from Rail Electricity Use	0.1	0.1	+	+	+	+	0.1	0.1	0.1	0.1	+	+	+	+	+	-31%
HFCs from Comfort Cooling	+	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	NA
HFCs from Refrigerated Transport	+	0.5	2.0	2.2	2.4	1.9	2.1	2.1	2.2	2.2	2.2	2.2	2.3	2.3	2.3	NA
Pipelines[c]	**36.0**	**38.2**	**35.2**	**34.4**	**36.4**	**32.5**	**31.1**	**32.2**	**32.3**	**34.2**	**35.6**	**36.7**	**37.1**	**37.8**	**40.1**	**11%**
Natural Gas	36.0	38.2	35.2	34.4	36.4	32.5	31.1	32.2	32.3	34.2	35.6	36.7	37.1	37.8	40.1	11%
Other Transportation	**11.8**	**11.3**	**12.1**	**11.1**	**10.9**	**10.1**	**10.2**	**10.2**	**9.9**	**10.2**	**9.5**	**8.5**	**9.5**	**9.0**	**8.3**	**-30%**
Lubricants	11.8	11.3	12.1	11.1	10.9	10.1	10.2	10.2	9.9	10.2	9.5	8.5	9.5	9.0	8.3	-30%
Non-Transportation Mobile Total	**128.8**	**146.8**	**158.3**	**172.3**	**177.0**	**181.7**	**188.7**	**190.7**	**195.8**	**194.8**	**194.2**	**197.7**	**204.3**	**207.0**	**209.8**	**63%**
Agricultural Equipment[d]	**31.4**	**37.0**	**39.2**	**41.4**	**42.5**	**43.6**	**46.6**	**47.3**	**49.6**	**49.0**	**45.9**	**47.2**	**48.2**	**50.0**	**51.5**	**64%**
Gasoline	7.3	8.3	5.8	7.1	7.4	7.6	9.8	9.6	11.0	9.6	5.7	6.1	6.2	7.2	7.8	7%
Diesel	24.1	28.7	33.4	34.3	35.1	36.0	36.8	37.7	38.6	39.4	40.3	41.1	41.9	42.8	43.7	81%
Construction/ Mining Equipment[e]	**42.4**	**49.4**	**55.8**	**60.1**	**61.8**	**63.6**	**65.4**	**66.5**	**67.9**	**68.4**	**69.9**	**71.2**	**73.6**	**74.8**	**76.4**	**80%**
Gasoline	4.4	4.0	3.1	5.8	6.1	6.4	6.7	6.2	6.2	5.1	5.2	5.0	5.9	5.5	5.7	30%
Diesel	38.0	45.4	52.7	54.2	55.7	57.2	58.8	60.3	61.8	63.3	64.8	66.3	67.8	69.3	70.8	86%
Other Equipment[f]	**55.0**	**60.4**	**63.4**	**70.9**	**72.7**	**74.5**	**76.7**	**76.9**	**78.3**	**77.4**	**78.4**	**79.3**	**82.5**	**82.3**	**81.8**	**49%**
Gasoline	40.3	42.6	42.5	49.3	50.5	51.7	53.1	52.7	53.4	51.8	52.2	52.4	54.9	54.0	52.9	31%
Diesel	14.7	17.8	20.9	21.5	22.2	22.9	23.5	24.2	24.9	25.6	26.2	26.9	27.6	28.3	28.9	97%
Transportation and Non-Transportation Mobile Total	**1,685.1**	**1847.1**	**2091.9**	**2092.5**	**2137.9**	**2135.4**	**2190.7**	**2212.7**	**2215.6**	**2226.3**	**2134.2**	**2064.7**	**2085.2**	**2063.4**	**2050.7**	**22%**

[a] Not including emissions from international bunker fuels.

[b] Fluctuations in emission estimates reflect data collection problems.

[c] Includes only CO_2 from natural gas used to power natural gas pipelines; does not include emissions from electricity use or non-CO_2 gases.

[d] Includes equipment, such as tractors and combines, as well as fuel consumption from trucks that are used off-road in agriculture.

[e] Includes equipment, such as cranes, dumpers, and excavators, as well as fuel consumption from trucks that are used off-road in construction.

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

+ Less than 0.05 Tg CO_2 Eq.

- Unreported or zero

NA = Not Applicable, as there were no HFC emissions allocated to the transport sector in 1990, and thus a growth rate cannot be calculated.

Table A- 114: Transportation and Mobile Source Emissions by Gas (Tg CO_2 Eq.)

	1990	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Percent Change 1990-2012
CO_2	1,636.4	1,769.3	1,977.1	1,974.6	2,020.3	2,018.2	2,072.9	2,095.6	2,099.3	2,112.9	2,023.1	1,956.6	1,981.4	1,966.3	1,959.5	20%
N_2O	44.0	54.0	53.1	50.4	46.4	42.8	40.2	36.9	33.8	29.0	25.5	22.7	20.7	18.5	16.5	-62%
CH_4	4.6	4.2	3.3	3.2	2.8	2.6	2.5	2.4	2.3	2.1	1.9	1.8	1.8	1.7	1.7	-63%
HFC	+	19.6	58.4	64.3	68.3	71.6	75.0	77.8	80.2	82.1	83.6	83.5	81.3	76.9	72.9	N/A
Total	**1,685.0**	**1,847.0**	**2,091.9**	**2,092.5**	**2,137.9**	**2,135.3**	**2,190.6**	**2,212.6**	**2,215.5**	**2,226.2**	**2,134.1**	**2,064.6**	**2,085.2**	**2,063.4**	**2,050.7**	**22%**

- Unreported or zero

NA = Not Applicable, as there were no HFC emissions allocated to the transport sector in 1990, and thus a growth rate cannot be calculated.

Figure A-4: Domestic Greenhouse Gas Emissions by Mode and Vehicle Type, 1990 to 2012 (Tg CO_2 Eq.)

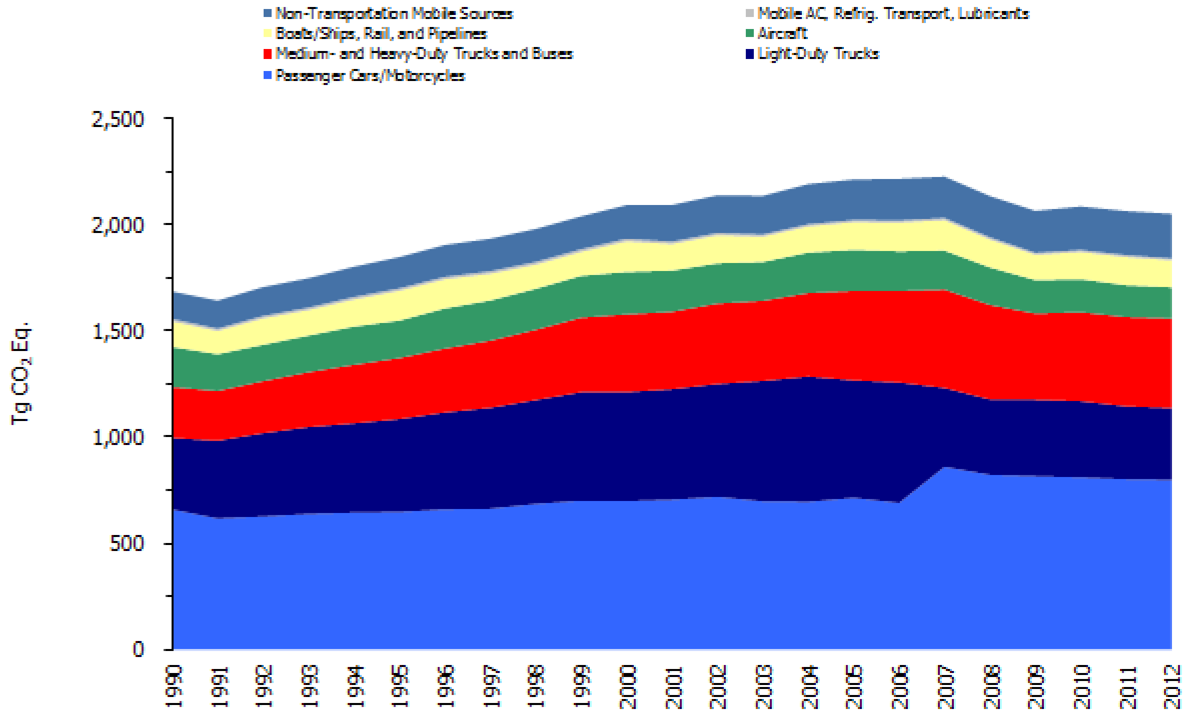

Table A- 115: Greenhouse Gas Emissions from Passenger Transportation (Tg CO_2 Eq.)

Vehicle Type	1990	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Percent Change 1990-2012
On-Road Vehicles	**1,004.1**	**1,094.1**	**1,223.2**	**1,235.7**	**1,260.2**	**1,275.2**	**1,299.9**	**1,279.4**	**1,269.1**	**1,249.4**	**1,194.5**	**1,192.3**	**1,185.1**	**1,162.2**	**1,155.1**	**15%**
Passenger Cars	657.4	646.0	696.6	703.2	716.9	695.6	693.1	712.6	688.0	855.4	817.9	811.5	805.8	798.0	793.8	21%
Light-Duty Trucks	336.6	437.1	513.5	520.4	531.6	567.1	589.9	553.1	566.9	371.7	354.8	359.9	359.1	343.1	338.4	1%
Buses	8.4	9.2	11.2	10.3	10.0	10.8	15.0	12.1	12.3	18.0	17.4	16.5	16.3	17.5	18.6	122%
Motorcycles	1.8	1.8	1.9	1.7	1.7	1.7	1.8	1.7	1.9	4.3	4.5	4.3	3.8	3.7	4.3	141%
Aircraft	**134.7**	**132.0**	**152.2**	**147.7**	**146.4**	**139.5**	**146.8**	**152.7**	**146.6**	**144.9**	**141.0**	**125.2**	**124.8**	**122.2**	**118.6**	**-12%**
General Aviation	43.0	35.8	35.9	43.7	45.1	36.9	41.9	40.1	30.1	24.4	30.5	21.2	26.7	22.5	19.9	-54%
Commercial Aircraft	91.7	96.2	116.3	104.0	101.3	102.6	104.9	112.6	116.5	120.5	110.5	104.0	98.1	99.6	98.6	8%
Recreational Boats	**14.5**	**16.4**	**12.7**	**17.4**	**17.4**	**17.4**	**17.4**	**17.4**	**17.3**	**17.3**	**17.0**	**16.9**	**16.8**	**16.8**	**16.8**	**15%**
Passenger Rail	**4.4**	**4.5**	**5.2**	**5.4**	**5.1**	**5.8**	**6.0**	**6.2**	**6.0**	**6.6**	**6.3**	**6.2**	**6.2**	**6.0**	**5.6**	**27%**
Total	**1,157.6**	**1,247.0**	**1,393.3**	**1,406.2**	**1,429.1**	**1,437.9**	**1,470.1**	**1,455.7**	**1,439.1**	**1,418.2**	**1,358.8**	**1,340.6**	**1,332.9**	**1,307.1**	**1,296.0**	**12%**

Note: Data from DOE (1993 through 2013) were used to disaggregate emissions from rail and buses. Emissions from HFCs have been included in these estimates.

Table A- 116: Greenhouse Gas Emissions from Domestic Freight Transportation (Tg CO_2 Eq.)

By Mode	1990	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	% Change 1990-2012
Trucking	231.1	277.8	354.6	353.8	368.1	365.9	377.7	408.4	418.6	444.7	427.0	389.2	402.9	402.4	403.4	75%
Freight Rail	34.5	39.1	42.8	43.1	43.1	43.7	46.2	46.7	49.0	47.8	44.4	37.2	40.0	42.0	41.2	19%
Ships and Other Boats	30.6	42.2	48.3	25.4	30.1	19.9	22.7	27.9	31.1	37.9	28.9	22.4	28.5	30.3	24.0	-22%
Pipelines[a]	36.0	38.2	35.2	34.4	36.4	32.5	31.1	32.2	32.3	34.2	35.6	36.7	37.1	37.8	40.1	11%
Commercial Aircraft	19.2	20.1	24.4	21.8	21.2	21.5	21.1	21.4	21.8	20.5	18.0	16.7	16.3	16.1	15.8	-18%
Total	**351.5**	**417.4**	**505.3**	**478.5**	**499.0**	**483.4**	**498.8**	**536.5**	**552.8**	**585.0**	**553.9**	**502.2**	**524.8**	**528.5**	**524.5**	**49%**

[a] Pipelines reflect CO_2 emissions from natural gas powered pipelines transporting natural gas

Note: Data from DOE (1993 through 2013) were used to disaggregate emissions from rail and buses. Emissions from HFCs have been included in these estimates.

3.3. Methodology for Estimating Emissions from Commercial Aircraft Jet Fuel Consumption

IPCC Tier 3B Method: Commercial aircraft jet fuel burn and carbon dioxide (CO_2) emissions estimates were developed by the U.S. Federal Aviation Administration (FAA) using radar-informed data from the FAA Enhanced Traffic Management System (ETMS) for 2000 through 2012 as modeled with the Aviation Environmental Design Tool (AEDT). This bottom-up approach is built from modeling dynamic aircraft performance for each flight occurring within an individual calendar year. The analysis incorporates data on the aircraft type, date, flight identifier, departure time, arrival time, departure airport, arrival airport, ground delay at each airport, and real-world flight trajectories. To generate results for a given flight within AEDT, the radar-informed aircraft data is correlated with engine and aircraft performance data to calculate fuel burn and exhaust emissions. Information on exhaust emissions for in-production aircraft engines comes from the International Civil Aviation Organization (ICAO) Aircraft Engine Emissions Databank (EDB). This bottom-up approach is in accordance with the Tier 3B method from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories.

International Bunkers: The IPCC guidelines define international aviation (International Bunkers) as emissions from flights that depart from one country and arrive in a different country. Bunker fuel emissions estimates for commercial aircraft were developed for this report for 2000 through 2012 using the same radar-informed data modeled with AEDT. Since this process builds estimates from flight-specific information, the emissions estimates for commercial aircraft can include emissions associated with the U.S. territories (i.e., American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands). However, to allow for the alignment of emissions estimates for commercial aircraft with other data that is provided without the U.S. territories, this annex includes emissions estimates for commercial aircraft both with and without the U.S. territories included.

Time Series and Analysis Update: The FAA incrementally improves the consistency, robustness, and fidelity of the CO_2 emissions modeling for commercial aircraft, which is the basis of the Tier3B inventories presented in this report. While the FAA does not anticipate significant changes to the AEDT model in the future, recommended improvements are limited by budget and time constraints, as well as data availability. For instance, previous reports included reported annual CO_2 emission estimates for 2000 through 2005 that were modeled using the FAA's System for assessing Aviation's Global Emissions (SAGE). That tool and its capabilities were significantly improved after it was incorporated and evolved into AEDT. For this report, the AEDT model was used to generate annual CO2 emission estimates for 2000, 2005, 2010, 2011 and 2012 only. The reported annual CO_2 emissions values for 2001 through 2004 were estimated from the previously reported SAGE data. Likewise, CO_2 emissions values for 2006 through 2009 were estimated by interpolation to preserve trends from past reports.

The radar-informed method is not possible for 1990 through 1999 because radar data sets are not available for years prior to 2000. Instead, the FAA applied a Tier3B methodology by developing Official Airline Guide (OAG) schedule-informed estimates modeled with AEDT and great circle trajectories for 1990, 2000 and 2010. The ratios between the OAG schedule-informed and the radar-informed inventories for the years 2000 and 2010 were applied to the 1990 OAG scheduled-informed inventory to generate the best possible CO_2 inventory estimate for commercial aircraft in 1990. The resultant 1990 CO_2 inventory served as the reference for generating the additional 1991-1999 emissions estimates, which were established using previously available trends.

Notes on Revised 1990 CO_2 Emissions Inventory for Commercial Aircraft: In 2013, the 1990 inventory was revised to achieve time series consistency. The observed change in 1990 emissions when compared to previous GHG inventory reports (EPA GHG Sources and Sinks Report circa 2000, 2002, 2007, 2010) was purely due to using a Tier3B methodology, and not reflective of revised industry performance and should not be used to infer or evaluate such performance.

To achieve time series consistency, the 1990 jet fuel burn was modeled with the latest AEDT version using great circle trajectories and OAG schedule information. There are uncertainties associated with the modeled 1990 data that do not exist for the modeled 2000 to 2012 data. Radar-based data is not available for 1990. The OAG schedule information generally includes fewer carriers than radar information, and this will result in a different fleet mix, and in turn, different CO_2 emissions than would be quantified using a radar-based data set. For this reason, the FAA adjusted the OAG-informed schedule for 1990 with a ratio based on radar-informed information. In addition, radar trajectories are also generally longer than great circle trajectories. The revised 1990 CO_2 emissions inventory now reflects only commercial aircraft jet fuel consumption, while previous reports may have aggregated jet fuel sales data from non-commercial aircraft into this category. Thus, it would be inappropriate to compare 1990 to future years for other than qualitative purposes.

The revised 1990 commercial aircraft CO_2 emissions inventory is approximately 3 percent lower than the 2012 CO_2 emissions inventory. It is important to note that the distance flown increased 41percent over this twenty-three-year period and that fuel burn and aviation activity trends over the past two decades indicate significant improvements in commercial aviation's ability to provide increased service levels while using less fuel.[57]

Methane Emissions: Contributions of methane (CH_4) emissions from commercial aircraft are reported as zero. Years of scientific measurement campaigns conducted at the exhaust exit plane of commercial aircraft gas turbine engines have repeatedly indicated that CH_4 emissions are consumed over the full mission flight envelope (*Aircraft Emissions of Methane and Nitrous Oxide during the Alternative Aviation Fuel Experiment*, Santoni et al., Environ. Sci. Technol., 2011, 45, 7075-7082). As a result, the U.S. Environmental Protection Agency published that "*...methane is no longer considered to be an emission from aircraft gas turbine engines burning Jet A at higher power settings and is, in fact, consumed in net at these higher powers.*"[58] In accordance with the following statements in the 2006 IPCC Guidelines (IPCC 2006), the FAA does not calculate CH_4 emissions for either the domestic or international bunker commercial aircraft jet fuel emissions inventories. *"Methane (CH_4) may be emitted by gas turbines during idle and by older technology engines, but recent data suggest that little or no CH_4 is emitted by modern engines." "Current scientific understanding does not allow other gases (e.g., N_2O and CH_4) to be included in calculation of cruise emissions." (IPCC 1999).*

Results: The graph and table below, four jet fuel burn values are reported for each calendar year. These values are comprised of domestic and international fuel burn totals for the US 50 States and the US 50 States + Territories. Data are presented for domestic defined as jet fuel burn from any commercial aircraft flight departing and landing in the US 50 States and for the US 50 States + Territories. The data presented as international is respective of the two different domestic definitions, and represents flights departing from the specified domestic area and landing anywhere in the world outside of that area.

Note that the graph and table present less fuel burn for the international US 50 States + Territories than for the international US 50 States. This is because the flights between the 50 states and US Territories are "international" when only the 50 states are defined as domestic, but they are "domestic" for the US 50 States + Territories definition.

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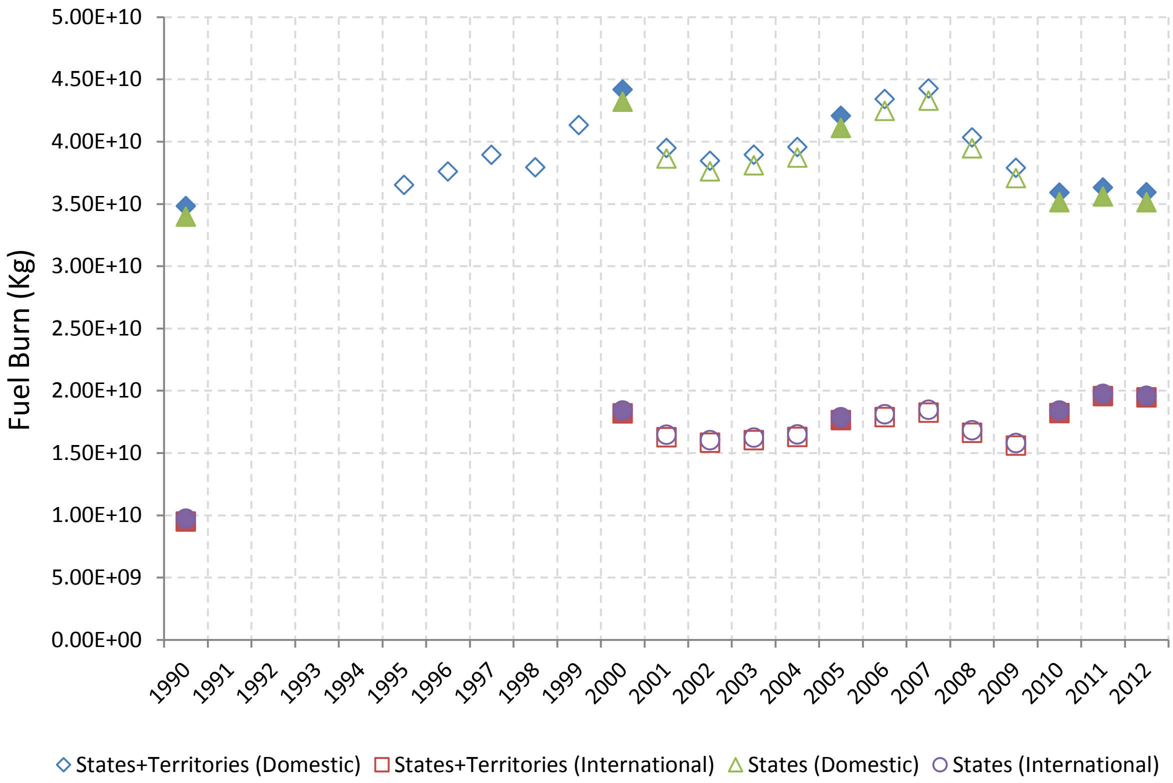
[57] Additional information on the AEDT modeling process is available at: http://www.faa.gov/about/office_org/headquarters_offices/apl/research/models/

[58] Recommended Best Practice for Quantifying Speciated Organic Gas Emissions from Aircraft Equipped with Turbofan, Turbojet and Turboprop Engines, EPA-420-R-09-901, May 27, 2009, http://www.epa.gov/otaq/aviation.htm.

Figure A-5: Commerical Aviation Fuel Burn for the United States and Terrirtories



Note: Hollow markers are estimates from data generated by prior tools and methods.
1990 is estimated using non-radar methods.

Table A- 117: Commercial Aviation Fuel Burn for the United States and Territories

Year	Region	Distance Flown	Fuel Burn (M Gallon)	Fuel Burn (Tbtu)	Fuel Burn (Kg)	CO_2 (Tg)
1990	Domestic US 50 States and US Territories	4,057,195,988	11,568	1,562	34,820,800,463	109.9
	International US 50 States and US Territories	599,486,893	3,155	426	9,497,397,919	30.0
	Domestic US 50 States	3,984,482,217	11,287	1,524	33,972,832,399	107.2
	International US 50 States	617,671,849	3,228	436	9,714,974,766	30.7
1995	Domestic US 50 States and US Territories	N/A	12,136	1,638	36,528,990,675	115.2
1996	Domestic US 50 States and US Territories	N/A	12,492	1,686	37,600,624,534	118.6
1997	Domestic US 50 States and US Territories	N/A	12,937	1,747	38,940,896,854	122.9
1998	Domestic US 50 States and US Territories	N/A	12,601	1,701	37,930,582,643	119.7
1999	Domestic US 50 States and US Territories	N/A	13,726	1,853	41,314,843,250	130.3
2000	Domestic US 50 States and US Territories	5,994,679,944	14,672	1,981	44,161,841,348	139.3
	International US 50 States and US Territories	1,309,565,963	6,040	815	18,181,535,058	57.4
	Domestic US 50 States	5,891,481,028	14,349	1,937	43,191,000,202	136.3
	International US 50 States	1,331,784,289	6,117	826	18,412,169,613	58.1
2001	Domestic US 50 States and US Territories	5,360,977,447	13,121	1,771	39,493,457,147	124.6
	International US 50 States and US Territories	1,171,130,679	5,402	729	16,259,550,186	51.3
	Domestic US 50 States	5,268,687,772	12,832	1,732	38,625,244,409	121.9
	International US 50 States	1,191,000,288	5,470	739	16,465,804,174	51.9
2002	Domestic US 50 States and US Territories	5,219,345,344	12,774	1,725	38,450,076,259	121.3
	International US 50 States and US Territories	1,140,190,481	5,259	710	15,829,987,794	49.9
	Domestic US 50 States	5,129,493,877	12,493	1,687	37,604,800,905	118.6
	International US 50 States	1,159,535,153	5,326	719	16,030,792,741	50.6
2003	Domestic US 50 States and US Territories	5,288,138,079	12,942	1,747	38,956,861,262	122.9

	International US 50 States and US Territories	1,155,218,577	5,328	719	16,038,632,384	50.6
	Domestic US 50 States	5,197,102,340	12,658	1,709	38,100,444,893	120.2
	International US 50 States	1,174,818,219	5,396	728	16,242,084,008	51.2
2004	Domestic US 50 States and US Territories	5,371,498,689	13,146	1,775	39,570,965,441	124.8
	International US 50 States and US Territories	1,173,429,093	5,412	731	16,291,460,535	51.4
	Domestic US 50 States	5,279,027,890	12,857	1,736	38,701,048,784	122.1
	International US 50 States	1,193,337,698	5,481	740	16,498,119,309	52.1
2005	Domestic US 50 States and US Territories	6,476,007,697	13,976	1,887	42,067,562,737	132.7
	International US 50 States and US Territories	1,373,543,928	5,858	791	17,633,508,081	55.6
	Domestic US 50 States	6,370,544,998	13,654	1,843	41,098,359,387	129.7
	International US 50 States	1,397,051,323	5,936	801	17,868,972,965	56.4
2006	Domestic US 50 States and US Territories	5,894,323,482	14,426	1,948	43,422,531,461	137.0
	International US 50 States and US Territories	1,287,642,623	5,939	802	17,877,159,421	56.4
	Domestic US 50 States	5,792,852,211	14,109	1,905	42,467,943,091	134.0
	International US 50 States	1,309,488,994	6,015	812	18,103,932,940	57.1
2007	Domestic US 50 States and US Territories	6,009,247,818	14,707	1,986	44,269,160,525	139.7
	International US 50 States and US Territories	1,312,748,383	6,055	817	18,225,718,619	57.5
	Domestic US 50 States	5,905,798,114	14,384	1,942	43,295,960,105	136.6
	International US 50 States	1,335,020,703	6,132	828	18,456,913,646	58.2
2008	Domestic US 50 States and US Territories	5,475,092,456	13,400	1,809	40,334,124,033	127.3
	International US 50 States and US Territories	1,196,059,638	5,517	745	16,605,654,741	52.4
	Domestic US 50 States	5,380,838,282	13,105	1,769	39,447,430,318	124.5
	International US 50 States	1,216,352,196	5,587	754	16,816,299,099	53.1
2009	Domestic US 50 States and US Territories	5,143,268,671	12,588	1,699	37,889,631,668	119.5
	International US 50 States and US Territories	1,123,571,175	5,182	700	15,599,251,424	49.2
	Domestic US 50 States	5,054,726,871	12,311	1,662	37,056,676,966	116.9
	International US 50 States	1,142,633,881	5,248	709	15,797,129,457	49.8
2010	Domestic US 50 States and US Territories	5,652,264,576	11,931	1,611	35,912,723,830	113.3
	International US 50 States and US Territories	1,474,839,733	6,044	816	18,192,953,916	57.4
	Domestic US 50 States	5,554,043,585	11,667	1,575	35,116,863,245	110.8
	International US 50 States	1,497,606,695	6,113	825	18,398,996,825	58.0
2011	Domestic US 50 States and US Territories	5,767,378,664	12,067	1,629	36,321,170,730	114.6
	International US 50 States and US Territories	1,576,982,962	6,496	877	19,551,631,939	61.7
	Domestic US 50 States	5,673,689,481	11,823	1,596	35,588,754,827	112.3
	International US 50 States	1,596,797,398	6,554	885	19,727,043,614	62.2
2012	Domestic US 50 States and US Territories	5,735,605,432	11,932	1,611	35,915,745,616	113.3
	International US 50 States and US Territories	1,619,012,587	6,464	873	19,457,378,739	61.4
	Domestic US 50 States	5,636,910,529	11,672	1,576	35,132,961,140	110.8
	International US 50 States	1,637,917,110	6,507	879	19,587,140,347	61.8

*Estimates for these years were derived from previously reported tools and methods

3.4. Methodology for Estimating CH_4 Emissions from Coal Mining

The methodology for estimating CH_4 emissions from coal mining consists of two steps. The first step is to estimate emissions from underground mines. There are two sources of underground mine emissions: ventilation systems and degasification systems. These 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 CH_4 emissions from surface mines and post-mining activities. In contrast to the methodology for underground mines, which uses mine-specific data, the methodology for estimating emissions from surface mines and post-mining activities consists of multiplying basin-specific coal production by basin-specific gas content and an emission factor.

Step 1: Estimate CH_4 Liberated and CH_4 Emitted from Underground Mines

Underground mines generate CH_4 from ventilation systems and from degasification systems. Some mines recover and use the generated CH_4, thereby reducing emissions to the atmosphere. Total CH_4 emitted from underground mines equals the CH_4 liberated from ventilation systems, plus the CH_4 liberated from degasification systems, minus CH_4 recovered and used.

Step 1.1: Estimate CH_4 Liberated from Ventilation Systems

All coal mines with detectable CH_4 emissions[59] use ventilation systems to ensure that CH_4 levels remain within safe concentrations. Many coal mines do not have detectable levels of CH_4, 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 CH_4 emissions levels at underground mines. MSHA maintains a database of measurement data from all underground mines with detectable levels of CH_4 in their ventilation air (MSHA 2013). Based on the four quarterly measurements, MSHA estimates average daily CH_4 liberated at each of the underground mines with detectable emissions.

For the years 1990 through 1996, 1998 through 2006, and 2008 through 2012, 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 A-118. Well over 90 percent of all ventilation emissions were concentrated in these subsets of approximately 125-150 mines. For 1997 and 2007, the complete MSHA databases for all 586 mines (in 1997) and 730 mines (in 2007) with detectable CH_4 emissions were obtained. These mines were assumed to account for 100 percent of CH_4 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 A-118). The proportion was then applied to the years 1990 through 2006 to account for the less than 5 percent of ventilation emissions coming from mines without MSHA data.

For 1990 through 1999, average daily CH_4 emissions were multiplied by the number of days in the year (i.e., coal mine assumed in operation for all four quarters) to determine the annual emissions for each mine. For 2000 through 2011, MSHA provided quarterly emissions. The average daily CH_4 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 CH_4 emissions were multiplied by 92 days. Total ventilation emissions for a particular year were estimated by summing emissions from individual mines.

Since 2009, two coal mines have destroyed a portion of their CH_4 emissions from ventilation systems using thermal oxidation technology. The amount of methane destroyed through these two projects was determined through publicly-available emission reduction project information (CAR 2013).

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[59] 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.

Table A-118: 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
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)*
2002	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)*
2003	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)*
2004	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)*
2005	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)*
2006	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)*
2007	All Mines with Detectable Emissions (Assumed to Account for 100% of Total)
2008	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 98.96% of Total)**
2009	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 98.96% of Total)**
2010	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 98.96% of Total)**
2011	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 98.96% of Total)**
2012	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 98.96% of Total)**

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

** Factor derived from a complete set of individual mine data collected for 2007.

Step 1.2: Estimate CH_4 Liberated from Degasification Systems

Coal mines use several different types of degasification systems to remove CH_4, including vertical wells and horizontal boreholes to recover CH_4 prior to mining of the coal seam. Gob wells and cross-measure boreholes recover CH4 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 CH_4 liberated. Thus, degasification emissions were estimated on a mine-by-mine basis based on other sources of available data. For those mines that sell CH_4 recovered from degasification systems to a pipeline, gas sales records were used to estimate CH4 liberated from degasification systems (see Step 1.3). For those mines venting CH_4 from degasification wells, data reported by mines to EPA's Greenhouse Gas Reporting Program (GHGRP) were used. Since 2011, EPA's GHGRP has required underground coal mines liberating greater than 36,500,000 actual cubic feet of CH_4 per year (about 14,700 metric tons CO_2 Eq.) to report their emissions directly to EPA.

Step 1.3: Estimate CH_4 Recovered from Degasification Systems and Utilized (Emissions Avoided)

In 2012, sixteen active coal mines had CH_4 recovery and use projects, of which fourteen mines sold the recovered CH_4 to a pipeline. One of the mines that sold gas to a pipeline also used CH_4 to fuel a thermal coal dryer. One mine used recovered CH_4 for electrical power generation, and another mine used recovered CH_4 to heat mine ventilation air. For mines that utilize CH_4 on-site, either the GHGRP (EPA 2013) or project-specific information (CAR 2013) was used to estimate CH_4 liberated from degasification systems.

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. Alabama and West Virginia state agencies provided gas sales data (GSA 2013; WVGES 2013), which were used to estimate emissions avoided for these projects. Additionally, coal mine operators provided information on eligible pre-drainage wells drilled in advance of mining (JWR 2010, 2013). Emissions avoided were attributed to the year in which the coal seam was mined. For example, if a coal mine recovered and sold CH_4 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 at the time it was mined through (e.g., five years of gas production). The coal mine operators with the largest CH_4 recovery and use projects provided this information (Consol 2013; JWR 2010, 2013), which was then used to estimate emissions avoided for a particular year.

Step 2: Estimate CH_4 Emitted from Surface Mines and Post-Mining Activities

Mine-specific data were not available for estimating CH_4 emissions from surface coal mines or for post-mining activities. For surface mines, basin-specific coal production was multiplied by basin-specific gas contents and a 150 percent emission factor (to account for CH_4 from over- and under-burden) to estimate CH_4 emissions. This emission factor was revised downward in 2012 from 200 percent based on more recent studies (King 1994; Saghafi 2013). The 150 percent emission factor was applied to all inventory years since 1990, retroactively. For post-mining activities, basin-specific coal production was multiplied by basin-specific gas contents and a 32.5 percent emission factor accounting for CH_4 desorption during coal transportation and storage (Creedy 1993).

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

The first step in estimating CH_4 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 A-119, which presents coal basin definitions by basin and by state.

The Energy Information Administration's (EIA) Annual Coal Report (2013) includes 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 A-119. For two states—West Virginia and Kentucky—county-level production data was used for the basin assignments because coal production occurred in geologically distinct coal basins within these states. Table A-120 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* CH_4 content of the surface coal in each basin. Based on analyses conducted in Canada and Australia on coals similar to those present in the U.S. (King 1994; Saghafi 2013), the surface mining emission factor used was conservatively estimated to be 150 percent of the *in situ* CH_4 content of the basin. Furthermore, the post-mining emission factors used were estimated to be 25 to 40 percent of the average *in situ* CH_4 content in the basin. For this analysis, the post-mining emission factor was determined to be 32.5 percent of the *in situ* CH_4 content in the basin. Table A-121 presents the average *in situ* content for each basin, along with the resulting emission factor estimates.

Step 2.3: Estimate CH_4 Emitted

The total amount of CH_4 emitted from surface mines and post-mining activities was calculated by multiplying the coal production in each basin by the appropriate emission factors.

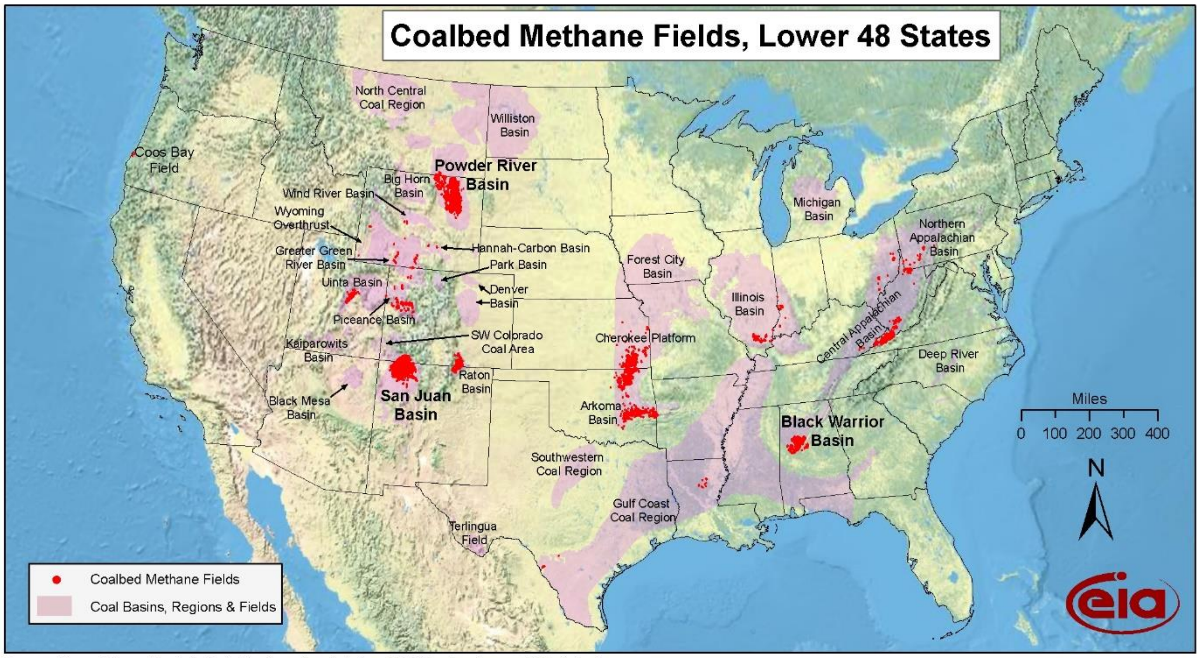
Table A-119 lists each of the major coal mine basins in the U.S. and the states in which they are located. As shown in Figure A-6, several coal basins span several states. Table A-120 shows annual underground, surface, and total coal production (in short tons) for each coal basin. Table A-121 shows the surface, post-surface, and post-underground emission factors used for estimating CH_4 emissions for each of the categories. Table A-122 presents annual estimates of CH_4 emissions for ventilation and degasification systems, and CH_4 used and emitted by underground coal mines. Table A-123 presents annual estimates of total CH_4 emissions from underground, post-underground, surface, and post-surface activities. Table A-124 provides the total net CH_4 emissions by state.

Table A-119: 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

Figure A-6: Locations of U.S Coal Basins



Source: Energy Information Administration based on data from USGS and various published studies
Updated: April 8, 2009

Table A-120: Annual Coal Production (Thousand Short Tons)

Basin	1990	2005	2008	2009	2010	2011	2012
Underground Coal Production	**423,556**	**368,611**	**357,074**	**332,061**	**337,155**	**345,607**	**342,387**
N. Appalachia	103,865	111,151	105,228	99,629	103,109	105,752	103,408
Cent. Appalachia	198,412	123,083	114,998	98,689	96,354	94,034	78,067
Warrior	17,531	13,295	12,281	11,505	12,513	10,879	12,570
Illinois	69,167	59,180	64,609	67,186	72,178	81,089	92,500
S. West/Rockies	32,754	60,865	55,781	50,416	44,368	45,139	45,052
N. Great Plains	1,722	572	3,669	4,248	8,208	8,179	10,345
West Interior	105	465	508	388	425	535	445
Northwest	+	+	+	+	+	+	+
Surface Coal Production	**602,753**	**762,191**	**813,321**	**740,175**	**764,709**	**754,871**	**672,748**
N. Appalachia	60,761	28,873	30,413	26,552	26,082	26,382	21,411
Cent. Appalachia	94,343	112,222	118,962	97,778	89,788	90,778	69,721
Warrior	11,413	11,599	11,172	10,731	11,406	10,939	9,705
Illinois	72,000	33,702	34,266	34,837	32,911	34,943	34,771
S. West/Rockies	43,863	42,756	34,283	32,167	28,889	31,432	30,475
N. Great Plains	249,356	474,056	538,387	496,290	507,995	502,734	455,320
West Interior	64,310	52,263	44,361	39,960	46,136	55,514	49,293
Northwest	6,707	6,720	1,477	1,860	2,151	2,149	2,052
Total Coal Production	**1,026,309**	**1,130,802**	**1,170,395**	**1,072,236**	**1,101,864**	**1,100,478**	**1,015,135**
N. Appalachia	164,626	140,024	135,641	126,181	129,191	132,134	124,819
Cent. Appalachia	292,755	235,305	233,960	196,467	186,142	184,812	147,788
Warrior	28,944	24,894	23,453	22,236	23,919	21,818	22,275
Illinois	141,167	92,882	98,875	102,023	105,089	116,032	127,271
S. West/Rockies	76,617	103,621	90,064	82,583	73,257	76,571	75,527
N. Great Plains	251,078	474,628	542,056	500,538	516,203	510,913	465,665
West Interior	64,415	52,728	44,869	40,348	46,561	56,049	49,738
Northwest	6,707	6,720	1,477	1,860	2,151	2,149	2,052

Source for 1990-2012 data: EIA (1990 through 2012), Annual Coal Report. U.S. Department of Energy, Washington, DC, Table 1. Source for 2012 data: spreadsheet for the 2012 Annual Coal Report.

Note: Totals may not sum due to independent rounding.

Table A-121: Coal Underground, Surface, and Post-Mining CH_4 Emission Factors (ft^3 per Short Ton)

Basin	Surface Average *in situ* Content	Underground Average *In situ* Content	Surface Mine Factors	Post-Mining Surface Factors	Post Mining Underground
Northern Appalachia	59.5	138.4	119.0	19.3	45.0
Central Appalachia (WV)	24.9	136.8	49.8	8.1	44.5
Central Appalachia (VA)	24.9	399.1	49.8	8.1	129.7
Central Appalachia (E KY)	24.9	61.4	49.8	8.1	20.0
Warrior	30.7	266.7	61.4	10.0	86.7
Illinois	34.3	64.3	68.6	11.1	20.9
Rockies (Piceance Basin)	33.1	196.4	66.2	10.8	63.8
Rockies (Uinta Basin)	16.0	99.4	32.0	5.2	32.3
Rockies (San Juan Basin)	7.3	104.8	14.6	2.4	34.1
Rockies (Green River Basin)	33.1	247.2	66.2	10.8	80.3
Rockies (Raton Basin)	33.1	127.9	66.2	10.8	41.6
N. Great Plains (WY, MT)	20.0	15.8	40.0	6.5	5.1
N. Great Plains (ND)	5.6	15.8	11.2	1.8	5.1
West Interior (Forest City, Cherokee Basins)	34.3	64.3	68.6	11.1	20.9
West Interior (Arkoma Basin)	74.5	331.2	149.0	24.2	107.6
West Interior (Gulf Coast Basin)	11.0	127.9	22.0	3.6	41.6
Northwest (AK)	16.0	160.0	32.0	1.8	52.0
Northwest (WA)	16.0	47.3	32.0	5.2	15.4

Sources: 1986 USBM Circular 9067, *Results of the Direct Method Determination of the Gas Contents of U.S. Coal Basins*, 1983 U.S. DOE Report (DOE/METC/83-76), *Methane Recovery from Coalbeds: A Potential Energy Source*, 1986-88 Gas Research Institute Topical Reports, A Geologic Assessment of Natural Gas from Coal Seams; *Surface Mines Emissions Assessment*, U.S. EPA Draft Report, November 2005.

Table A-122: Underground Coal Mining CH_4 Emissions (Billion Cubic Feet)

Activity	1990	2005	2008	2009	2010	2011	2012
Ventilation Output	112	75	100	114	117	97	90
Adjustment Factor for Mine Data*	97.8%	97.8%	99.0%	99.0%	99%	99%	99%
Adjusted Ventilation Output	114	77	101	115	118	98	91
Degasification System Liberated	54	48	49	49	58	48	45
Total Underground Liberated	168	124	150	163	177	147	137
Recovered & Used	(14)	(37)	(40)	(40)	(49)	(42)	(38)
Total	**154**	**87**	**110**	**123**	**128**	**104**	**98**

* Refer to Table A-118.

Note: Totals may not sum due to independent rounding

Table A-123: Total Coal Mining CH_4 Emissions (Billion Cubic Feet)

Activity	1990	2005	2008	2009	2010	2011	2012
Underground Mining	154	87	110	123	128	104	98
Surface Mining	22	25	27	24	24	24	21
Post-Mining (Underground)	19	16	15	14	14	14	14
Post-Mining (Surface)	5	5	6	5	5	5	5
Total	**200**	**132**	**157**	**166**	**171**	**148**	**138**

Note: Totals may not sum due to independent rounding.

Table A-124: Total Coal Mining CH_4 Emissions by State (Million Cubic Feet)

State	1990	2005	2008	2009	2010	2011	2012
Alabama	32,097	15,789	20,992	22,119	21,377	18,530	18,129
Alaska	50	42	43	54	63	63	60
Arizona	151	161	107	100	103	108	100
Arkansas	5	+	237	119	130	348	391
California	1	+	-	-	-	-	-
Colorado	10,187	13,441	12,871	13,999	16,470	11,187	9,305
Illinois	10,180	6,488	7,568	7,231	8,622	7,579	9,763
Indiana	2,232	3,303	5,047	5,763	5,938	6,203	7,374
Iowa	24	+	-	-	-	-	-
Kansas	45	11	14	12	8	2	1
Kentucky	10,018	6,898	9,986	12,035	12,303	10,592	7,993
Louisiana	64	84	77	73	79	168	80
Maryland	474	361	263	219	238	263	197

Mississippi	-		199		159	193	224	154	165
Missouri	166		3		15	28	29	29	26
Montana	1,373		1,468		1,629	1,417	1,495	1,445	1,160
New Mexico	363		2,926		3,411	3,836	3,956	4,187	2,148
North Dakota	299		306		303	306	296	289	281
Ohio	4,406		3,120		3,686	4,443	3,614	3,909	3,389
Oklahoma	226		825		932	624	436	360	499
Pennsylvania	21,864		17,904		20,684	22,939	23,372	17,708	17,773
Tennessee	276		115		86	69	67	60	35
Texas	1,119		922		783	704	823	922	887
Utah	3,587		4,787		5,524	5,449	5,628	3,651	3,624
Virginia	46,041		8,649		9,223	8,042	9,061	8,526	6,516
Washington	146		154		-	-	-	-	-
West Virginia	48,335		29,745		36,421	40,452	40,638	35,709	33,608
Wyoming	6,671		14,745		16,959	15,627	16,032	15,916	14,507
Total	**200,399**		**132,481**		**157,112**	**165,854**	**171,000**	**147,908**	**138,012**

Zero Cubic Feet

+ 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.

3.5. Methodology for Estimating CH_4 and CO_2 Emissions from Natural Gas Systems

As described in the main body text on Natural Gas Systems, the GHG Inventory methodology involves the calculation of CH_4 and CO_2 emissions for over 100 emissions sources, and then the summation of emissions for each natural gas sector stage.

Step 1: Calculate Potential Methane

Potential Methane Factors

The primary basis for potential CH_4 factors and emission factors for non-combustion-related CO_2 emissions from the U.S. natural gas industry is a detailed study by the Gas Research Institute and EPA (EPA/GRI 1996). The EPA/GRI study developed over 80 CH_4 emission factors to characterize emissions from the various components within the operating stages of the U.S. natural gas system. Since the time of this study, practices and technologies have changed. While this study still represents best available data in many cases, using these emission factors alone to represent actual emissions without adjusting for emissions controls would in many cases overestimate emissions. For this reason, "potential methane" are calculated using the data, and then more recent data on voluntary and regulatory emission reduction activities (step 3) is deducted to calculate actual emissions. See main body text on Natural Gas Systems for more information.

For certain CH_4 emissions sources, new data and information allows for net emissions to be calculated directly: gas well completions and workovers with hydraulic fracturing, liquids unloading, condensate storage tanks, and centrifugal compressors. For these sources, EPA developed emissions factors that directly reflect the use of control technologies. For gas well completions and workovers with hydraulic fracturing, separate emissions estimates were developed for hydraulically fractured completions and workovers that vent, flared hydraulic fracturing completions and workovers, hydraulic fracturing completions and workovers with RECs, and hydraulic fracturing completions and workovers with RECs that flare. For liquids unloading, separate emissions estimates were developed for wells with plunger lifts, and wells without plunger lifts. Likewise, for condensate tanks, emissions estimates were developed for tanks with and without control devices. Finally, for centrifugal compressors, separate emissions estimates were developed for compressors with wet and dry seals.

For potential CH_4 factors and emission factors used in the Inventory, see Table A-125 to Table A-130. Methane compositions from GTI 2001 are adjusted year to year using gross production for National Energy Modeling System (NEMS) oil and gas supply module regions from the EIA. These adjusted region-specific annual CH_4 compositions are presented in Table A-131 (for general sources), Table A-132 (for gas wells without hydraulic fracturing), and Table A-133 (for gas wells with hydraulic fracturing). Therefore, emission factors may vary from year to year due to slight changes in the CH_4 composition between each NEMS oil and gas supply module region.

1990-2012 Inventory updates to potential emission factors and emission factors

The current Inventory includes an update to emission factors for gas well completions and workovers with hydraulic fracturing. Technology- specific national emission factors were developed based on 2011 and 2012 GHGRP data. The emission factors used for gas well completions and workovers with hydraulic fracturing are not potential factors, but are factors for actual emissions because control technologies are taken into account through the use of separate emission factors for each of the aforementioned categories. The updated factors are included in Table A-125.

Activity Data

Activity data were taken from the following sources: DrillingInfo, Inc (DrillingInfo 2014); American Gas Association (AGA 1991–1998); Bureau of Ocean Energy Management, Regulation and Enforcement (previous Minerals and Management Service) (BOEMRE 2011a, 2011b, 2011c, 2011d); Monthly Energy Review (EIA 2012f, 2012g, 2012h, 2011a, 2011b, 2011c, 2011d); Natural Gas Liquids Reserves Report (EIA 2005); Natural Gas Monthly (EIA 2012c, 2012d, 2012e, 2013a, 2013b, 2013c); the Natural Gas STAR Program annual emissions savings (EPA 2012a, 2013c); Oil and Gas Journal (OGJ 1997–2013); Pipeline and Hazardous Materials Safety Administration (PHMSA 2013); Federal Energy Regulatory Commission (FERC 2011); GHGRP data for natural gas systems (40 CFR 98, subpart W); and other Energy Information Administration publications (EIA 2001, 2004, 2010, 2011, 2012i, 2014). Data for estimating emissions from hydrocarbon production tanks were incorporated (EPA 1999). Coalbed CH_4 well activity factors were taken from the Wyoming Oil and Gas Conservation Commission (Wyoming 2013) and the Alabama State Oil and Gas Board (Alabama 2013). Activity data are presented in Table A-125 through Table A-130.

For many sources, recent direct activity data were not available. For these sources, either 2011 data was used as proxy for 2012 data or a set of industry activity data drivers was developed and was used to update activity data. Drivers include statistics on gas production, number of wells, system throughput, miles of various kinds of pipe, and other statistics that characterize the changes in the U.S. natural gas system infrastructure and operations. For example, recent data on various types of field separation equipment in the production stage (i.e., heaters, separators, and dehydrators) were unavailable. EPA determined that each of these types of field separation equipment relate to the number of non-associated gas wells. Using the number of each type of field separation equipment estimated by GRI/EPA in 1992, and the number of non-associated gas wells in 1992, EPA developed a factor that is used to estimate the number of each type of field separation equipment throughout the time series. The key activity drivers are presented in Table A-134.

EPA used DI Desktop, a production database maintained by DrillingInfo, Inc. (DrillingInfo) (DrillingInfo 2014), covering U.S. oil and natural gas wells to populate activity data for associated gas wells, non-associated gas wells, gas wells with hydraulic fracturing, and completions with hydraulic fracturing. EPA queried DI Desktop for relevant data on an individual well basis—including location, natural gas and liquids (i.e., oil and condensate) production by year, drill type (e.g., horizontal or vertical), and date of completion or first production. Associated gas wells were identified as any well within DI Desktop that EPA classified as producing "oil" or "oil and gas" based on the production type description and that had non-zero natural gas and liquids production. Non-associated gas wells were identified as any well that met either of the following criteria: (1) classified as "oil" or "oil and gas" producing and had zero liquids production, but non-zero natural gas production; or (2) classified as "gas" producing and had non-zero gas production. Both oil and condensate are included in the liquids production data in DI Desktop; therefore, the count of associated gas wells may include wells that produce gas and condensate only. Gas wells with hydraulic fracturing were assumed to be the subset of the non-associated gas wells that were horizontally drilled and/or located in an unconventional formation (i.e., shale, tight sands, or coalbed). Unconventional formations were identified based on well basin, reservoir, and field data reported in DI Desktop referenced against a formation type crosswalk developed by EIA (EIA 2012a).

For 1990 through 2010, gas well completions with hydraulic fracturing were identified as a subset of the gas wells with hydraulic fracturing that had a date of completion or first production in the specified year. To calculate workovers for 1990 through 2010, EPA applied a refracture rate of 1 percent (i.e. 1 percent of all wells with hydraulic fracturing are assumed to be refractured in a given year) to the total counts of wells with hydraulic fracturing from the DrillingInfo data. For 2011 and 2012, EPA used GHGRP data for the total number of well completions and workovers. The GHGRP data represents a subset of the national completions and workovers, due to the reporting threshold, and therefore using this data without scaling it up to national level results in an underestimate. However, because EPA's GHGRP counts of completions and workovers were higher than national counts of completions and workovers, obtained using DIDesktop data, EPA directly used the GHGPR data for completions and workovers for 2011 and 2012.

The methodological update for gas well completions and workovers with hydraulic fracturing required updated activity data on RECs use and flaring for use with the new emission factors. EPA calculated the percentage of gas well completions and workovers with hydraulic fracturing in the each of the four categories using 2011 Subpart W data. EPA assumed 0 percent RECs use from 1990 through 2000, used GHGRP RECs percentage for 2011 and 2012, and then used linear interpolation between the 2000 and 2011 percentages. For flaring, EPA used an assumption of 10 percent (the average of the percent of completions and workovers that were flared in 2011 and 2012 GHGRP data) flaring from 1990-2010 to recognize that some flaring has occurred over that time period. For 2011 and 2012, EPA used the GHGRP data on flaring.

Step 2: Compile Reductions Data

The emissions calculated in Step 1 above represent expected emissions from an activity in the absence of emissions controls (with the exceptions of gas well completions and workovers with hydraulic fracturing, liquids unloading, centrifugal compressors, and condensate tanks, as noted above), and do not take into account any use of technologies or practices that reduce emissions. To take into account use of such technologies, data were collected on voluntary and regulatory reductions. Voluntary reductions included in the Inventory were those reported to Gas STAR for activities such as replacing a high bleed pneumatic device with a low bleed device and replacing wet seals with dry seals at reciprocating compressors. Regulatory actions reducing emissions include NESHAP regulations for dehydrator vents and condensate tanks.

Voluntary reductions. Industry partners report CH_4 emission reductions by project to the Natural Gas STAR Program. The reductions from the implementation of specific technologies and practices (e.g., vapor recovery units, centrifugal compressors are calculated by the reporting partners using actual measurement data or equipment-specific emission factors. Natural Gas STAR Partners do not report reductions when they are required due to regulation. Therefore, the Inventory assumes there is no overlap between the reductions reported through Natural Gas STAR and reductions due to state regulations. The reductions undergo quality assurance and quality control checks to identify errors, inconsistencies, or irregular data before being incorporated into the Inventory. In general, the Inventory uses aggregated Gas STAR reductions by natural gas system stage (i.e., production, processing, transmission and storage, and distribution). However, aggregate emissions reductions data by Gas STAR technology are provided for several sources, as shown in Table A-135 of the Annex. For those sources, EPA has also used data on potential emissions, and the Gas STAR data on reductions, to calculate net emissions, as shown in Table A-141 of the Annex. Many of the activities reported to Gas Star are cross-cutting and apply to more than one emissions source and therefore cannot be assigned to one emissions source, but instead are included in the "other" category. For Inventory sources with emission factors that already take into account the use of control technologies (i.e., gas well completions and workovers with hydraulic fracturing, liquids unloading, and condensate storage tanks) Natural Gas STAR reported reductions for those activities are not incorporated into the Inventory, as this would double count reductions. CH_4 emission reductions from the Natural Gas STAR Program are summarized in Table A-135.

Federal regulations. The 1990 Clean Air Act (CAA) sets limits on the amount of hazardous air pollutants (HAPs) that can be emitted in the United States. The NESHAP regulations set the standards to limit emissions of HAPs. The emission sources are required to use the Maximum Achievable Control Technology (MACT), giving the operators flexibility to choose the type of control measure(s) to implement. In regards to the oil and natural gas industry, the NESHAP regulation addresses HAPs from the oil and natural gas production sectors and the natural gas transmission and storage sectors of the industry. Though the regulation deals specifically with HAPs reductions, methane emissions are also incidentally reduced.

The NESHAP regulation requires that glycol dehydration unit vents and storage tanks that have HAP emissions and exceed a gas throughput and liquids throughput threshold, respectively, be connected to a closed loop emission control system that reduces emissions by 95 percent. Also, gas processing plants exceeding the threshold natural gas throughput limit are required to routinely implement Leak Detection and Repair (LDAR) programs. The emissions reductions achieved as a result of NESHAP regulations were calculated using data provided in the Federal Register Background Information Document (BID) for this regulation. The BID provides the levels of control measures in place before the enactment of regulation. The emissions reductions were estimated by analyzing the portion of the industry without control measures already in place that would be impacted by the regulation. CH_4 emission reductions from federal regulations, such as NESHAP, are summarized in Table A-136. In addition to the NESHAP applicable to natural gas, future Inventories will reflect the 2012 NSPS for oil and gas. By separating gas well completions and workovers with hydraulic fracturing into four categories and developing control technology-specific methane emission factors for each category, EPA is implicitly accounting for NSPS reductions from hydraulically fractured gas wells. The rule also has VOC reduction requirements for compressors, storage vessels, pneumatic controllers, and equipment leaks at processing plants, which will also impact CH_4 emissions in future Inventories.

Step 3: Calculate Net Emissions

For CH_4, the reductions described above in Step 2 are summed and deducted from the potential CH_4 emissions calculated in Step 1. These net emissions are reported in the Natural Gas Systems inventory text.

The same procedure for estimating CH_4 emissions holds true for estimating non-energy related CO_2 emissions, except the emission estimates are not adjusted for reductions due to the Natural Gas STAR program or regulations.

Produced natural gas is composed of primarily CH_4, but as shown in Table A-142, the natural gas contains, in some cases, as much as 8 percent CO_2. The same vented and fugitive natural gas that led to CH_4 emissions also contains a certain volume of CO_2. Accordingly, the CO_2 emissions for each sector can be estimated using the same activity data for these vented and fugitive sources. The emission factors used to estimate CH_4 were also used to calculate non-combustion CO_2 emissions. The Gas Technology Institute's (GTI, formerly GRI) Unconventional Natural Gas and Gas Composition Databases (GTI 2001) were used to adapt the CH_4 emission factors into non-combustion related CO_2 emission factors. Additional information about CO_2 content in transmission quality natural gas was obtained from numerous U.S. transmission companies to help further develop the non-combustion CO_2 emission factors. For the CO_2 content used to develop CO_2 emission factors from CH4 potential factors, see Table A-142. The detailed source emission estimates for CH_4 and CO_2 from the production sector are presented in Table A-137 and Table A-137, respectively.

In the processing sector, the CO_2 content of the natural gas remains the same as the CO_2 content in the production sector for the equipment upstream of the acid gas removal unit because produced natural gas is usually only minimally treated after being produced and then transported to natural gas processing plants via gathering pipelines. The CO_2 content in gas for the remaining equipment that is downstream of the acid gas removal is the same as in pipeline quality gas. The EPA/GRI study estimates the average CH_4 content of natural gas in the processing sector to be 87 percent CH_4. Consequently, the processing sector CO_2 emission factors were developed using CH_4 emission factors, proportioned to reflect the CO_2 content of either produced natural gas or pipeline quality gas using the same methodology as the production sector. The detailed source emission estimates for CH_4 and CO_2 from the processing sector are presented in Table A-138 and Table A-144, respectively.

For the transmission sector, CO_2 content in natural gas transmission pipelines was estimated for the top 20 transmission pipeline companies in the United States (separate analyses identified the top 20 companies based on gas throughput and total pipeline miles). The weighted average CO_2 content in the transmission pipeline quality gas in both cases—total gas throughput and total miles of pipeline—was estimated to be about 1 percent. To estimate the CO_2 emissions for the transmission sector, the CH_4 emission factors were proportioned from the 93.4 percent CH_4 reported in EPA/GRI (1996) to reflect the 1 percent CO_2 content found in transmission quality natural gas. The detailed source emissions estimates for CH_4 and CO_2 for the transmission sector are presented in Table A-139 and Table A-145, respectively.

The natural gas in the distribution sector of the system has the same characteristics as the natural gas in the transmission sector. The CH_4 content (93.4 percent) and CO_2 content (1 percent) are identical to transmission segment contents due to the absence of any further treatment between sector boundaries. Thus, the CH_4 emissions factors were converted to CO_2 emission factors using the same methodology as discussed for the transmission sector. The detailed source emission estimates for CH_4 and CO_2 for the distribution sector are presented in Table A-140 and Table A-146, respectively.

Three exceptions to this methodology are CO_2 emissions from flares, CO_2 from acid gas removal units, and CO_2 from condensate tanks. In the case of flare emissions, a direct CO_2 emission factor from EIA (1996) was used. This emission factor was applied to the portion of offshore gas that is not vented and all of the gas reported as vented and flared onshore by EIA, including associated gas. The amount of CO_2 emissions from an acid gas unit in a processing plant is equal to the difference in CO_2 concentrations between produced natural gas and pipeline quality gas applied to the throughput of the plant. This methodology was applied to the national gas throughput using national average CO_2 concentrations in produced gas (3.45 percent) and transmission quality gas (1 percent). Data were unavailable to use annual values for CO_2 concentration. For condensate tanks, a series of E&P Tank (EPA 1999) simulations provide the total CO_2 vented per barrel of condensate throughput from fixed roof tank flash gas for condensate gravities of API 45 degree and higher. The ratios of emissions to throughput were used to estimate the CO_2 emission factor for condensate passing through fixed roof tanks.

Table A-125 through Table A-130 display the 2012 activity data, CH_4 emission factors, and calculated potential CH_4 emissions for each stage.

The tables provide references for emission factors and activity data in footnotes (i.e., lettered footnotes). The tables also provide information on which method was used for supplying activity data for 2012 (i.e., numbered footnotes).

Table A-125: 2012 Data and Calculated CH_4 Potential Emissions (Mg) for the Natural Gas Production Stage, by NEMS Region

	2012 EPA Inventory Values				
Activity	**Activity Data**		**Emission Factor (Potential)[aa]**		**Calculated Potential (Mg)[bb]**
North East					
Gas Wells					
NE - Associated Gas Wells[cc,dd]	38,770	wells[a,1]	NA		NA
NE - Non-associated Gas Wells (less wells with hydraulic fracturing)	112,607	wells[a,1]	7.67	scfd/well[b]	6,071.08
NE - Gas Wells with Hydraulic Fracturing	46,367	wells[a,1]	7.54	scfd/well[b]	2,457.18
Field Separation Equipment					
Heaters	318	heaters[b,2]	15.38	scfd/heater[b]	34.37
Separators	112,872	separators[b,2]	0.97	scfd/separator[b]	771.31
Dehydrators	22,164	dehydrators [b,2]	23.53	scfd/dehydrator[b]	3,665.46
Meters/Piping	7,910	meters [c,2]	9.75	scfd/meter[b]	542.00
Gathering Compressors					
Small Reciprocating Compressors	159	compressors [b,2]	289.63	scfd/compressor[b]	323.68
Large Reciprocating Compressors	24	compressors [b,2]	16,447.52	scfd/compressor[b]	2,774.99
Large Reciprocating Stations	3	stations [b,2]	8,920.47	scfd/station[b]	188.13
Pipeline Leaks	77,956	miles [c,2]	57.50	scfd/mile[b]	31,508.62
Drilling, Well Completion, and Well Workover					
Gas Well Completions without Hydraulic Fracturing[ee]	268	completions/yr [d,2]	791	scf/completion[b]	4.08
Gas Well Workovers without Hydraulic Fracturing	4,898	workovers/yr [a,1]	2,647	scf/workover[b]	249.74
Gas Well Completions and Workovers with Hydraulic Fracturing	2,985 384	completions/yr[o] workovers/yr[o]		See Table A-126[p]	68,559.0
Well Drilling	6,359	wells[f,1]	2,751	scf/well[g]	336.92
Normal Operations					
Pneumatic Device Vents	77,261	controllers [b,2]	373	scfd/device[b]	202,695.69
Chemical Injection Pumps	795	active pumps [b,2]	268	scfd/pump[b]	1,499.03
Kimray Pumps	6,487,241	MMscf/yr [b,2]	1,073	scf/MMscf[b]	134,073.18
Dehydrator Vents	7,280,854	MMscf/yr [b,2]	298	scf/MMscf[b]	41,805.34
Condensate Tank Vents					
Condensate Tanks without Control Devices	1	MMbbl/yr [h,1]	21.87	scf/bbl[i,ff]	421.22
Condensate Tanks with Control Devices	1	MMbbl/yr [h,1]	4.37	scf/bbl[i,ff]	84.24
Compressor Exhaust Vented					
Gas Engines	-	MMHPhr [b,2]	0.26	scf/HPhr[b]	-
Liquids Unloading					
Liquids Unloading (with plunger lifts)	6,924	venting wells[a,j,2a,j,2]	268,185	scfy/venting well[j,gg]	35,764.16
Liquids Unloading (without plunger lifts)	17,906	venting wells[a,j,2]	141,646	scfy/venting well[j,gg]	48,849.27
Blowdowns					
Vessel Blowdown	135,353	vessels [b,2]	84	scfy/vessel[b]	219.96
Pipeline Blowdown	77,956	miles (gathering) [c,2]	334	scfy/mile[b]	501.85
Compressor Blowdown	159	compressors [b,2]	4,082	scfy/compressor[b]	12.50
Compressor Starts	159	compressors [b,2]	9,133	scfy/compressor[b]	27.96
Upsets					
Pressure Relief Valves	354,796	PRV [b,2]	36.78	scfy/PRV[b]	251.32
Mishaps	19,489	miles [c,2]	724	scf/mile[b]	271.64
Midcontinent					
Gas Wells					
MC - Associated Gas Wells[cc,dd]	27,470	wells[a,1]	NA		-
MC - Non-associated Gas Wells (less wells with hydraulic fracturing)	77,896	wells[a,1]	7.45	scfd/well[b]	4,080.19
MC - Gas Wells with Hydraulic Fracturing	30,156	wells[a,1]	8.35	scfd/well[b]	1,770.61
Field Separation Equipment					
Heaters	43,869	heaters [b,2]	14.90	scfd/heater[b]	4,595.66
Separators	47,003	separators [b,2]	0.94	scfd/separator[b]	311.30

Dehydrators	15,064	dehydrators [b,2]	95.54	scfd/dehydrator[b]	10,117.92
Meters/Piping	143,186	meters [c,2]	9.45	scfd/meter[b]	9,509.40
Gathering Compressors					
Small Reciprocating Compressors	12,210	compressors [b,2]	280.71	scfd/compressor[b]	24,094.82
Large Reciprocating Compressors	24	compressors [b,2]	15,941	scfd/compressor[b]	2,689.55
Large Reciprocating Stations	3	stations [b,2]	8,646	scfd/station[b]	182.34
Pipeline Leaks	81,359	miles [c,2]	55.72	scfd/mile[b]	31,871.63
Drilling, Well Completion, and Well Workover					
Gas Well Completions without Hydraulic Fracturing[ee]	182	completions/yr [d,2]	768	scf/completion[b]	2.70
Gas Well Workovers without Hydraulic Fracturing	3,388	workovers/yr [a,1]	2,572	scf/workover[b]	167.84
Gas Well Completions and Workovers with Hydraulic Fracturing	1,139 143	completions/yr[o] workovers/yr[o]		See Table A-126[p]	26,118.0
Well Drilling	4,322	wells [f,1]	2,666	scf/well[g]	221.95
Normal Operations					
Pneumatic Device Vents	167,589	controllers [b,2]	362	scfd/device[b]	426,133.39
Chemical Injection Pumps	15,343	active pumps [b,2]	260	scfd/pump[b]	28,044.95
Kimray Pumps	4,409,271	MMscf/yr [b,2]	1,040	scf/MMscf[b]	88,321.70
Dehydrator Vents	4,948,676	MMscf/yr [b,2]	288.9	scf/MMscf[b]	27,539.58
Condensate Tank Vents					
Condensate Tanks without Control Devices	19	MMbbl/yr [h,1]	302.75	scf/bbl[i,ff]	107,874.48
Condensate Tanks with Control Devices	19	MMbbl/yr [h,1]	60.55	scf/bbl[i,ff]	21,574.90
Compressor Exhaust Vented					
Gas Engines	19,041	MMHPhr [b,2]	0.25	scf/HPhr[b]	92,278.23
Liquids Unloading					
Liquids Unloading (with plunger lifts)	2,516	venting wells [a,j,2]	1,140,052	scfy/venting well[j,gg]	55,244.84
Liquids Unloading (without plunger lifts)	4,469	venting wells [a,j,2]	190,179	scfy/venting well[j,gg]	16,369.26
Blowdowns					
Vessel Blowdown	105,936	vessels [b,2]	82	scfy/vessel[b]	166.85
Pipeline Blowdown	81,359	miles (gathering) [c,2]	324	scfy/mile[b]	507.64
Compressor Blowdown	12,210	compressors [b,2]	3,957	scfy/compressor[b]	930.47
Compressor Starts	12,210	compressors [b,2]	8,852	scfy/compressor[b]	2,081.60
Upsets					
Pressure Relief Valves	241,149	PRV [b,2]	36	scfy/PRV[b]	165.56
Mishaps	20,340	miles [c,2]	701	scf/mile[b]	274.77
Rocky Mountain					
Gas Wells					
RM - Associated Gas Wells[cc,dd]	32,598	wells [a,1]	NA		-
RM - Non-associated Gas Wells (less wells with hydraulic fracturing)	9,665	wells [a,1]	35.05	scfd/well[b]	2,381.29
RM - Gas Wells with Hydraulic Fracturing	73,755	wells [a,1]	40.72	scfd/well[b]	21,115.06
Field Separation Equipment					
Heaters	38,040	heaters [b,2]	56.73	scfd/heater[b]	15,171.70
Separators	41,627	separators [b,2]	120	scfd/separator[b]	35,099.35
Dehydrators	11,630	dehydrators [b,2]	89.58	scfd/dehydrator[b]	7,324.14
Meters/Piping	97,399	meters [c,2]	52.01	scfd/meter[b]	35,608.50
Gathering Compressors					
Small Reciprocating Compressors	9,260	compressors [b,2]	263.20	scfd/compressor[b]	17,133.02
Large Reciprocating Compressors	32	compressors [b,2]	14,947	scfd/compressor[b]	3,362.38
Large Reciprocating Stations	4	stations [b,2]	8,107	scfd/station[b]	227.95
Pipeline Leaks	107,797	miles [c,2]	52.25	scfd/mile[b]	39,594.37
Drilling, Well Completion, and Well Workover					
Gas Well Completions without Hydraulic Fracturing[ee]	141	completions/yr [d,2]	705	scf/completion[b]	1.91
Gas Well Workovers without Hydraulic Fracturing	420	workovers/yr [a,1]	2,360	scf/workover[b]	19.11
Gas Well Completions and Workovers with Hydraulic Fracturing	2,334 275	completions/yr[o] workovers/yr[o]		See Table A-126[p]	53,087.0
Well Drilling	3,337	wells [f,1]	2,500	scf/well[g]	160.66
Normal Operations					
Pneumatic Device Vents	122,127	controllers [b,2]	339	scfd/device[b]	291,165.83
Chemical Injection Pumps	14,849	active pumps [b,2]	244	scfd/pump[b]	25,447.90

Kimray Pumps	3,404,114	MMscf/yr [b,2]	975	scf/MMscf[b]	63,934.16
Dehydrator Vents	3,820,555	MMscf/yr [b,2]	270.9	scf/MMscf[b]	19,935.30
Condensate Tank Vents					
Condensate Tanks without Control Devices	5	MMbbl/yr [h,1]	21.87	scf/bbl[i,ff]	1,895.47
Condensate Tanks with Control Devices	5	MMbbl/yr [h,1]	4.37	scf/bbl[i,ff]	379.09
Compressor Exhaust Vented					
Gas Engines	14,701	MMHPhr [b,2]	0.24	scf/HPhr[b]	66,798.21
Liquids Unloading					
Liquids Unloading (with plunger lifts)	10,741	venting wells [a,j,2]	119,523	scfy/venting well[j,gg]	24,726.01
Liquids Unloading (without plunger lifts)	1,267	venting wells [a,j,2]	1,998,082	scfy/venting well[j,gg]	48,758.03
Blowdowns					
Vessel Blowdown	91,296	vessels [b,2]	77	scfy/vessel[b]	134.82
Pipeline Blowdown	107,797	miles (gathering) [c,2]	304	scfy/mile[b]	630.64
Compressor Blowdown	9,260	compressors [b,2]	3,710	scfy/compressor[b]	661.63
Compressor Starts	9,260	compressors [b,2]	8,300	scfy/compressor[b]	1,480.15
Upsets					
Pressure Relief Valves	186,176	PRV b,2	33	scfy/PRV[b]	119.84
Mishaps	26,949	miles c,2	658	scf/mile[b]	341.34
Produced Water from Coal Bed Methane					
Powder River	20,602,022,700	gallons produced water [k,1]	2.3E-09	Gg/gallon water drainage [k]	47,244.27
South West					
Gas Wells					
SW - Associated Gas Wells[cc,dd]	155,119	wells [a,1]	NA		-
SW - Non-associated Gas Wells (less wells with hydraulic fracturing)	13,860	wells [a,1]	37.24	scfd/well[b]	3,628.27
SW - Gas Wells with Hydraulic Fracturing	27,627	wells [a,1]	37.24	scfd/well[b]	7,232.19
Field Separation Equipment					
Heaters	11,243	heaters [b,2]	58.97	scfd/heater[b]	4,661.03
Separators	23,316	separators [b,2]	125	scfd/separator[b]	20,435.18
Dehydrators	5,784	dehydrators [b,2]	93.11	scfd/dehydrator[b]	3,786.17
Meters/Piping	55,885	meters [c,2]	54.06	scfd/meter[b]	21,236.97
Gathering Compressors					
Small Reciprocating Compressors	5,642	compressors [b,2]	274	scfd/compressor[b]	10,851.59
Large Reciprocating Compressors	16	compressors [b,2]	15,536	scfd/compressor[b]	1,747.50
Large Reciprocating Stations	2	stations [b,2]	8,426	scfd/station[b]	118.47
Pipeline Leaks	60,832	miles [c,2]	54.31	scfd/mile[b]	23,225.26
Drilling, Well Completion, and Well Workover					
Gas Well Completions without Hydraulic Fracturing[ee]	70	completions/yr [d,2]	749	scf/completion[b]	1.01
Gas Well Workovers without Hydraulic Fracturing	603	workovers/yr [a,1]	2,507	scf/workover[b]	29.12
Gas Well Completions and Workovers with Hydraulic Fracturing	649 116	completions/yr[o] workovers/yr[o]		See Table A-126[p]	15,601.0
Well Drilling	1,660	wells [f,1]	2,598	scf/well[g]	83.05
Normal Operations					
Pneumatic Device Vents	55,095	controllers [b,2]	353	scfd/device[b]	136,534.04
Chemical Injection Pumps	2,531	active pumps [b,2]	253	scfd/pump[b]	4,508.22
Kimray Pumps	1,692,957	MMscf/yr [b,2]	1,014	scf/MMscf[b]	33,050.39
Dehydrator Vents	1,900,064	MMscf/yr [b,2]	282	scf/MMscf[b]	10,305.44
Condensate Tank Vents					
Condensate Tanks without Control Devices	10	MMbbl/yr [h,1]	303	scf/bbl[i,ff]	55,395.00
Condensate Tanks with Control Devices	10	MMbbl/yr [h,1]	60.55	scf/bbl[i,ff]	11,079.00
Compressor Exhaust Vented					
Gas Engines	7,311	MMHPhr [b,2]	0.25	scf/HPhr[b]	34,530.94
Liquids Unloading					
Liquids Unloading (with plunger lifts)	1,379	venting wells [a,j,2]	2,856	scfy/venting well[j,gg]	75.85
Liquids Unloading (without plunger lifts)	8,078	venting wells [a,j,2]	77,899	scfy/venting well[j,gg]	12,119.67
Blowdowns					
Vessel Blowdown	40,343	vessels [b,2]	80	scfy/vessel[b]	61.93
Pipeline Blowdown	60,832	miles (gathering) [c,2]	316	scfy/mile[b]	369.92

Compressor Blowdown	5,642	compressors [b,2]	3,856	scfy/compressor[b]	419.06
Compressor Starts	5,642	compressors [b,2]	8,627	scfy/compressor[b]	937.49
Upsets					
Pressure Relief Valves	92,590	PRV [b,2]	35	scfy/PRV[b]	61.95
Mishaps	15,208	miles [c,2]	684	scf/mile[b]	200.22
West Coast					
Gas Wells					
WC - Associated Gas Wells[cc,dd]	29,726	wells [a,1]	NA		-
WC - Non-associated Gas Wells (less wells with hydraulic fracturing)	1,999	wells [a,1]	42.49	scfd/well[b]	597.13
WC - Gas Wells with Hydraulic Fracturing	95	wells [a,1]	42.49	scfd/well[b]	28.38
Field Separation Equipment					
Heaters	2,094	heaters [b,2]	67.29	scfd/heater[b]	990.60
Separators	1,529	separators [b,2]	142	scfd/separator[b]	1,528.80
Dehydrators	292	dehydrators [b,2]	106	scfd/dehydrator[b]	218.06
Meters/Piping	3,994	meters [c,2]	61.68	scfd/meter[b]	1,732.08
Gathering Compressors					
Small Reciprocating Compressors	2,431	compressors [b,2]	312	scfd/compressor[b]	5,335.45
Large Reciprocating Compressors	8	compressors [b,2]	17,728	scfd/compressor[b]	997.03
Large Reciprocating Stations	1	stations [b,2]	9,615	scfd/station[b]	67.59
Pipeline Leaks	16,712	miles [c,2]	61.97	scfd/mile[b]	7,280.76
Drilling, Well Completion, and Well Workover					
Gas Well Completions without Hydraulic Fracturing[ee]	4	completions/yr [d,2]	855	scf/completion[b]	0.06
Gas Well Workovers without Hydraulic Fracturing	87	workovers/yr [a,1]	2,861	scf/workover[b]	4.79
Gas Well Completions and Workovers with Hydraulic Fracturing	2 1	completions/yr[o] workovers/yr[o]		See Table A-126[p]	123.0
Well Drilling	84	wells [f,1]	2,965	scf/well[g]	4.78
Normal Operations					
Pneumatic Device Vents	2,098	controllers [b,2]	402	scfd/device[b]	5,933.29
Chemical Injection Pumps	1,422	active pumps [b,2]	289	scfd/pump[b]	2,890.21
Kimray Pumps	85,450	MMscf/yr [b,2]	1,157	scf/MMscf[b]	1,903.54
Dehydrator Vents	95,903	MMscf/yr [b,2]	321	scf/MMscf[b]	593.54
Condensate Tank Vents					
Condensate Tanks without Control Devices	10	MMbbl/yr [h,1]	21.87	scf/bbl[i,ff]	4,212.16
Condensate Tanks with Control Devices	10	MMbbl/yr [h,1]	4.37	scf/bbl[i,ff]	842.43
Compressor Exhaust Vented					
Gas Engines	369	MMHPhr [b,2]	0.28	scf/HPhr[b]	1,988.81
Liquids Unloading					
Liquids Unloading (with plunger lifts)	159	wells [a,j,2]	317,292	scfy/venting well[j,gg]	971.66
Liquids Unloading (without plunger lifts)	142	wells [a,j,2]	279,351	scfy/venting well[j,gg]	764.00
Blowdowns					
Vessel Blowdown	3,915	vessels [b,2]	90.94	scfy/vessel[b]	6.86
Pipeline Blowdown	16,712	miles (gathering) [c,2]	360	scfy/mile[b]	115.96
Compressor Blowdown	2,431	compressors [b,2]	4,400	scfy/compressor[b]	206.04
Compressor Starts	2,431	compressors [b,2]	9,844	scfy/compressor[b]	460.94
Upsets					
Pressure Relief Valves	4,673	PRV [b,2]	40	scfy/PRV[b]	3.57
Mishaps	4,178	miles [c,2]	780	scf/mile[b]	62.77
Gulf Coast					
Gas Wells					
GC - Associated Gas Wells[cc,dd]	39,709	wells [a,1]	NA		-
GC - Non-associated Gas Wells (less wells with hydraulic fracturing)	27,024	wells [a,1]	7.96	scfd/well[b]	1,511.56
GC - Gas Wells with Hydraulic Fracturing	49,862	wells [a,1]	7.96	scfd/well[b]	2,789.34
Field Separation Equipment					
Heaters	17,222	heaters [b,2]	64.60	scfd/heater[b]	7,821.18
Separators	50,591	separators [b,2]	136.57	scfd/separator[b]	48,571.24
Dehydrators	10,719	dehydrators [b,2]	102.00	scfd/dehydrator[b]	7,686.19
Meters/Piping	90,288	meters [c,2]	59.21	scfd/meter[b]	37,584.36
Gathering Compressors					
Small Reciprocating Compressors	6,228	compressors [b,2]	300	scfd/compressor[b]	13,120.51
Large Reciprocating Compressors	32	compressors [b,2]	17,019	scfd/compressor[b]	3,828.46

Large Reciprocating Stations	4	stations [b,2]	9,230	scfd/station[b]	259.55
Pipeline Leaks	100,479	miles [c,2]	59.49	scfd/mile[b]	42,022.30
Drilling, Well Completion, and Well Workover					
Gas Well Completions without Hydraulic Fracturing[ee]	130	completions/yr [d,2]	820	scf/completion[b]	2.05
Gas Well Workovers without Hydraulic Fracturing	1,176	workovers/yr [a,1]	2,746	scf/workover[b]	62.18
Gas Well Completions and Workovers with Hydraulic Fracturing	2,357 279	completions/yr[o] workovers/yr[o]		See Table A-126[p]	53,643.0
Well Drilling	3,076	wells [f,1]	2,846	scf/well[g]	168.61
Normal Operations					
Pneumatic Device Vents	53,436	controllers [b,2]	386	scfd/device[b]	145,057.07
Chemical Injection Pumps	2,537	active pumps [b,2]	278	scfd/pump[b]	4,951.09
Kimray Pumps	3,137,482	MMscf/yr [b,2]	1,110	scf/MMscf[b]	67,094.63
Dehydrator Vents	3,521,304	MMscf/yr [b,2]	308	scf/MMscf[b]	20,920.77
Condensate Tank Vents					
Condensate Tanks without Control Devices	43	MMbbl/yr [h,1]	21.87	scf/bbl[i,ff]	17,901.69
Condensate Tanks with Control Devices	43	MMbbl/yr [h,1]	4.37	scf/bbl[i,ff]	3,580.34
Compressor Exhaust Vented					
Gas Engines	13,549	MMHPhr [b,2]	0.27	scf/HPhr[b]	70,100.25
Liquids Unloading					
Liquids Unloading (with plunger lifts)	1,784	venting wells [a,j,2]	61,758	scfy/venting well[j,gg]	2,121.99
Liquids Unloading (without plunger lifts)	5,445	venting wells [a,j,2]	265,120	scfy/venting well[j,gg]	27,803.30
Blowdowns					
Vessel Blowdown	78,533	vessels [b,2]	87	scfy/vessel[b]	132.05
Pipeline Blowdown	100,479	miles (gathering) [c,2]	346	scfy/mile[b]	669.31
Compressor Blowdown	6,228	compressors [b,2]	4,224	scfy/compressor[b]	506.67
Compressor Starts	6,228	compressors [b,2]	9,450	scfy/compressor[b]	1,133.51
Upsets					
Pressure Relief Valves	171,593	PRV [b,2]	38	scfy/PRV[b]	125.77
Mishaps	25,120	miles [c,2]	749	scf/mile[b]	362.28
Produced Water from Coal Bed Methane Wells					
Black Warrior	5,517	wells [l,1]	2.33E-03	Gg/well [l]	12,779.20
Offshore Platforms					
Shallow water Gas Platforms (GoM and Pacific)	1,973	shallow water gas platforms [m,3]	19,178	scfd/platform [n]	266,066.46
Deepwater Gas Platforms (GoM and Pacific)	41	deepwater gas platforms [m,3]	79,452	scfd/platform [n]	22,950.41
Regulatory Reductions (Gg)					**(99.2)**
Voluntary Reductions (Gg)					**(1,635.7)**
Total Reductions (Gg)					**(1,734.8)**
Total Potential Emissions (Gg)					**3,726.6**
Total Net Emissions (Gg)					**1,991.8**

[a] DI Desktop (2014)

[b].EPA/GRI (1996), Methane Emissions from the Natural Gas Industry

[c] ICF (1996), Estimation of Activity Factors for the Natural Gas Exploration and Production Industry in the U.S.

[d] API/ICF memo (1997)

[e] EPA NSPS Technical Support Document (2012)

[f] EIA Monthly Energy Review

[g] Radian (1992), Global Emissions of Methane Sources

[h] EIA US Crude Oil, Natural Gas, and Natural Gas Liquids Reserves Annual Report

[i] EP&P/API Tank Calc runs

[j] API/ANGA (2012), Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production – Summary and Analysis of API and ANGA Survey Responses

[k] Wyoming Oil and Gas Conservation Commission (2013)

[l] Alabama State Oil and Gas Board (2013)

[m] Bureau of Ocean Energy Management, Regulation and Enforcement (2011)

[n] MMS (2000), 2000 Gulfwide Offshore Activity Data System

[o] 2012 GHGRP - Subpart W data

[p] Emissions for hydraulic fracturing completions and workovers are split into 4 categories and the same emission factors (shown in Table A-2) are used for all NEMS regions. For more details, refer to EPA memo "Updating GHG Inventory Estimate for Hydraulically Fractured." The factors for hydraulically fractured completions and workovers in Table A-2 represent actual emissions and can be used to calculate emissions directly

[q] Emissions for hydraulic fracturing completions and workovers are calculated together.

[aa] Emission factors listed in this table are for potential emissions (unless otherwise indicated in a footnote). For many of these sources, emission reductions are subtracted from potential emissions to calculate net emissions. For this reason, emission factors presented in these tables cannot be used to directly estimate net emissions from these sources. See detailed explanation of methodology above.

[bb] Totals may not sum due to independent rounding.

[cc] Emissions from oil wells that produce associated gas are estimated in the Petroleum Systems model. In the Natural Gas Systems model, the oil wells counts are used as a driver only.

[dd] NA = not applicable (i.e., this data is not applicable for the Natural Gas Systems model).

[ff] Emission factors for condensate tanks represent actual emissions and can be used to calculate emissions directly.

[gg] Emission factors for liquids unloading represent actual emissions and can be used to calculate emissions directly.

[1] Activity data for 2012 available from source.

[2] Ratios relating other factors for which activity data are available.

[3] 2011 activity data are used to determine some or all of the 2012 activity.

Table A-126: 2012 National Activity Data and Emission Factors, and Emissions (Mg), by category for Hydraulically Fractured Gas Well Completions and Workovers

	2012 EPA Inventory Values				
Activity	**Activity Data**		**Emission Factor**		**Emissions (Mg)[aa]**
Hydraulic Fracturing Completions and Workovers that vent	4,688	completions and workovers/year[a]	41	Mg/comp or workover[b]	192,208
Flared Hydraulic Fracturing Completions and Workovers	775	completions and workovers/year[a]	5	Mg/comp or workover[b]	3,875
Hydraulic Fracturing Completions and Workovers with RECs	3,386	completions and workovers/year[a]	3	Mg/comp or workover[b]	10,158
Hydraulic Fracturing Completions and Workovers with RECs that flare	1,815	completions and workovers/year[a]	6	Mg/comp or workover[b]	10,890

[a] 2012 GHGRP - Subpart W data. The GHGRP data represents a subset of national completions and workovers, due to the reporting threshold. Please see the section on “Activity Data” above for more information and the Planned Improvements section of the Inventory report.

[b] Emissions for hydraulic fracturing completions and workovers are split into 4 categories and the same emission factors are used for all NEMS regions. For more details, refer to EPA memo “Updating GHG Inventory Estimate for Hydraulically Fractured.”

[aa] Totals may not sum due to independent rounding.

Table A-127: U.S. Activity Data for Hydraulic Fracturing Completions and Workovers split by 4 categories

Activity	1990	1995	2000	2005	2011[a]	2012[a]
Hydraulic Fracturing Completions and Workovers that vent	5,345	4,852	7,434	10,129	4,678	4,688
Flared Hydraulic Fracturing Completions and Workovers	591	536	823	1,464	1,381	775
Hydraulic Fracturing Completions and Workovers with RECs	-	-	-	2,302	3,882	3,386
Hydraulic Fracturing Completions and Workovers with RECs that flare	-	-	-	767	1,292	1,815
Total	**5,936**	**5,388**	**8,257**	**14,662**	**11,233**	**10,664**

[a] 2011 and 2012 GHGRP - Subpart W data

Table A-128: 2012 Data and CH_4 Emissions (Mg) for the Natural Gas Processing Stage

	2012 EPA Inventory Values				
Activity	**Activity Data**		**Emission Factor (Potential)[aa]**		**Calculated Potential Emissions (Mg)**
Normal Fugitives					
Plants	606	plants[a,1]	7,906	scfd/plant[b]	33,680.5
Reciprocating Compressors	5,624	compressors [c,2]	11,196	scfd/compressor[b]	442,633.5
Centrifugal Compressors (wet seals)	658	compressors [d,2]	51,370	scfd/compressor[d]	237,724.1
Centrifugal Compressors (dry seals)	248	compressors [d,2]	25,189	scfd/compressor[d]	43,936.6
Compressor Exhaust					
Gas Engines	40,403	MMHPhr [c,2]	0.24	scf/HPhr[b]	186,760.5
Gas Turbines	47,907	MMHPhr [c,2]	0.01	scf/HPhr[b]	5,259.3
AGR Vents	307	AGR units[b,2]	6,083	scfd/AGR[b]	13,134.2
Kimray Pumps	1,463,675	MMscf/yr [c,2]	178	scf/MMscf[b]	5,010.8
Dehydrator Vents	13,186,262	MMscf/yr [c,2]	122	scf/MMscf[b]	30,869.7
Pneumatic Devices	606	gas plants [a,1]	164,721	scfy/plant[b]	1,922.6
Compressor Exhaust					
Blowdowns/Venting	606	gas plants [a,1]	4,060	Mscfy/plant[b]	47,386.5
Regulatory Reductions (Gg)					**(16.3)**
Voluntary Reductions (Gg)					**(140.4)**
Total Reductions (Gg)					**(156.8)**
Total Potential Emissions (Gg)					**1,048.3**
Total Net Emissions (Gg)					**891.5**

[a] Oil and Gas Journal

[b] EPA/GRI (1996), Methane Emissions from the Natural Gas Industry

[c] ICF (2008), Natural Gas Model Activity Factor Basis Change

[d] ICF (2010), Emissions from Centrifugal Compressors

[aa] Emission factors listed in this table are for potential emissions (unless otherwise indicated in a footnote). For many of these sources, emission reductions are subtracted from potential emissions to calculate net emissions. For this reason, emission factors presented in these tables cannot be used to directly estimate net emissions from these sources. See detailed explanation of methodology above.

[1] Activity data for 2012 available from source.

[2] Ratios relating other factors for which activity data are available.

Table A-129: 2012 Data and CH_4 Emissions (Mg) for the Natural Gas Transmission Stage

	2012 EPA Inventory Values				
Activity	Activity Data		Emission Factor (Potential)[aa]		Calculated Potential Emissions (Mg)
Fugitives					
Pipeline Leaks	303,126	miles[a,1]	1.55	Scfd/ mile[b]	3,311.4
Compressor Stations (Transmission)					
Station	1,799	stations[c,2]	8,778	Scfd/station[b]	111,037.1
Reciprocating Compressor	7,235	compressors [c,2]	15,205	Scfd/ compressor[b]	773,294.3
Centrifugal Compressor (wet seals)	659	compressors [d,2]	50,222	Scfd/ compressor[d]	232,825.7
Centrifugal Compressor (dry seals)	66	compressors [d,2]	32,208	Scfd/ compressor[d]	14,971.9
Compressor Stations (Storage)					
Station	344	stations [e,2]	21,507	Scfd/ station[b]	52,013.2
Reciprocating Compressor	1,012	compressors [e,2]	21,116	Scfd/ compressor[b]	150,224.7
Centrifugal Compressor (wet seals)	70	compressors [d,2]	45,441	Scfd/ compressor[d]	22,346.7
Centrifugal Compressor (dry seals)	29	compressors [d,2]	31,989	Scfd/ compressor[d]	6,531.7
Wells (Storage)	16,042	wells [b,2]	115	Scfd/well[b]	12,912.2
M&R (Trans. Co. Interconnect)	2,698	stations [c,2]	3,984	scfd/station[b]	75,573.6
M& R (Farm Taps + Direct Sales)	80,009	stations [c,2]	31	scfd/station[b]	17,548.7
Vented and Combusted					
Dehydrator vents (Transmission)	1,146,991	MMscf/year [b,2]	93.72	scf/MMscf[b]	2,070.4
Dehydrator vents (Storage)	1,782,492	MMscf/year [b,2]	117	scf/MMscf[b]	4,022.9
Compressor Exhaust					
Engines (Transmission)	50,908	MMHPhr [b,2]	0.24	scf/HPhr[b]	235,315.3
Turbines (Transmission)	12,147	MMHPhr [b,2]	0.01	scf/HPhr[b]	1,333.5
Engines (Storage)	4,387	MMHPhr [b,2]	0.24	scf/HPhr[b]	20,277.1
Turbines (Storage)	1,541	MMHPhr [b,2]	0.01	scf/HPhr[b]	169.2
Generators (Engines)	2,491	MMHPhr [b,2]	0.24	scf/HPhr[b]	11,515.2
Generators (Turbines)	29	MMHPhr [b,2]	0.01	scf/HPhr[b]	3.2
Pneumatic Devices Transmission + Storage					
Pneumatic Devices Transmission	70,827	devices [f,2]	162,197	Scfy/device[b]	221,256.9
Pneumatic Devices Storage	13,542	devices [e,2]	162,197	Scfy/device[b]	42,304.0
Routine Maintenance/Upsets					
Pipeline venting	303,126	miles [a,1]	31.65	Mscfy/mile[b]	184,779.2
Station Venting Transmission + Storage					
Station Venting Transmission	1,799	compressor stations [c,2]	4,359	Mscfy/station[b]	151,065.9
Station Venting Storage	344	compressor stations [e,2]	4,359	Mscfy/station[b]	28,882.0
LNG Storage					-
LNG Stations	70	stations [f,g,3]	21,507	scfd/station[b]	10,622.8
LNG Reciprocating Compressors	270	compressors [f,g,3]	21,116	scfd/comp[b]	40,146.5
LNG Centrifugal Compressors	64	compressors [f,g,3]	30,573	scfd/comp[b]	13,766.0
LNG Compressor Exhaust					
LNG Engines	579	MMHPhr [f,g,3]	0.24	scf/HPhr[b]	2,677.7
LNG Turbines	113	MMHPhr [f,g,3]	0.01	scf/HPhr[b]	12.4
LNG Station Venting	70	stations [f,g,3]	4,359	Mscfy/station[b]	5,898.6
LNG Import Terminals					
LNG Stations	8	stations [f,g,3]	21,507	scfd/station[b]	1,164.2
LNG Reciprocating Compressors	37	compressors [f,g,3]	21,116	scfd/compressor[b]	5,551.8
LNG Centrifugal Compressors	7	compressors [f,g,3]	30,573	scfd/compressor[b]	1,418.5
LNG Compressor Exhaust					
LNG Engines	774	MMHPhr [f,g,3]	0.24	scf/HPhr[b]	3,576.6
LNG Turbines	178	MMHPhr [f,g,3]	0.01	scf/HPhr[b]	19.5
LNG Station Venting	8	stations [f,g,3]	4,359	Mscfy/station[b]	646.4
Regulatory Reductions (Gg)					**(0.0)**
Voluntary Reductions (Gg)					**(390.1)**

Total Reductions (Gg)	**(390.1)**
Total Potential Emissions (Gg)	**2,461.1**
Total Net Emissions (Gg)	**2,071.0**

[a] Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS) (2013)

[b] EPA/GRI (1996), Methane Emissions from the Natural Gas Industry

[c] ICF (2008), Natural Gas Model Activity Factor Basis Change

[d] ICF (2010), Emissions from Centrifugal Compressors

[e] ICF (1997), Additional Changes to Activity Factors for Portions of the Gas Industry

[f] ICF (1996), Estimation of Activity Factors for the Natural Gas Exploration and Production Industry in the U.S.

[g] EIA (2004), US LNG Markets and Uses

[1] Activity data for 2012 available from source.

[2] Ratios relating other factors for which activity data are available.

[3] 2011 activity data are used to determine some or all of the 2012 activity (to be updated).

[aa] Emission factors listed in this table are for potential emissions (unless otherwise indicated in a footnote). For many of these sources, emission reductions are subtracted from potential emissions to calculate net emissions. For this reason, emission factors presented in these tables cannot be used to directly estimate net emissions from these sources. See detailed explanation of methodology above.

Table A-130: 2012 Data and CH_4 Emissions (Mg) for the Natural Gas Distribution Stage

	2012 EPA Inventory Values				
Activity	**Activity Data**		**Emission Factor (Potential)[aa]**		**Calculated Potential Emissions (Mg)**
Pipeline Leaks					
Mains—Cast Iron	32,418	miles [a,1]	239	Mscf/mile-yr[b]	149,037.3
Mains—Unprotected steel	63,727	miles [a,1]	110	Mscf/mile-yr[b]	135,245.1
Mains—Protected steel	487,225	miles [a,1]	3.07	Mscf/mile-yr[b]	28,779.7
Mains—Plastic	661,100	miles [a,1]	9.91	Mscf/mile-yr[c]	126,181.9
Services—Unprotected steel	3,916,353	services [a,1]	1.70	Mscf/service[b]	128,287.1
Services Protected steel	14,951,473	services [a,1]	0.18	Mscf/service[b]	50,824.7
Services—Plastic	45,147,410	services [a,1]	0.01	Mscf/service[b]	8,085.1
Services—Copper	1,009,255	services [a,1]	0.25	Mscf/service[b]	4,943.6
Meter/Regulator (City Gates)					
M&R >300	3,465	stations [d,2]	180	scfh/station[b]	105,101.3
M&R 100-300	12,644	stations [d,2]	95.60	scfh/station[b]	203,935.5
M&R <100	6,758	stations [d,2]	4.31	scfh/station[b]	4,914.3
Reg >300	3,788	stations [d,2]	162	scfh/station[b]	103,468.3
R-Vault >300	2,225	stations [d,2]	1.30	scfh/station[b]	487.9
Reg 100-300	11,459	stations [d,2]	40.50	scfh/station[b]	78,300.9
R-Vault 100-300	5,148	stations [d,2]	0.18	scfh/station[b]	156.3
Reg 40-100	34,387	stations [d,2]	1.04	scfh/station[b]	6,033.8
R-Vault 40-100	30,494	stations [d,2]	0.09	scfh/station[b]	445.0
Reg <40	14,581	stations [d,2]	0.13	scfh/station[b]	327.2
Customer Meters					
Residential	35,693,769	outdoor meters [b,2]	143	scfy/meter[b]	98,493.2
Commercial/Industry	4,481,003	meters [b,2]	47.90	scfy/meter[b]	4,134.0
Routine Maintenance					
Pressure Relief Valve Releases	1,244,470	mile main [a,1]	0.05	Mscf/mile[b]	1,198.4
Pipeline Blowdown	1,156,453	miles [b,2]	0.10	Mscfy/mile[b]	2,271.9
Upsets					
Mishaps (Dig-ins)	1,156,453	miles [b,2]	1.59	Mscfy/mile[b]	35,414.5
Regulatory Reductions (Gg)					**(0.0)**
Voluntary Reductions (Gg)					**(44.8)**
Total Reductions (Gg)					**(44.8)**
Total Potential Emissions (Gg)					**1,276.1**
Total Net Emissions (Gg)					**1,231.3**

[a] Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS) (2012)

[b] EPA/GRI (1996), Methane Emissions from the Natural Gas Industry

[c] ICF (2005), Plastic Pipe Emission Factors

[d] ICF (2008), Natural Gas Model Activity Factor Basis Change

[aa] Emission factors listed in this table are for potential emissions (unless otherwise indicated in a footnote). For many of these sources, emission reductions are subtracted from potential emissions to calculate net emissions. For this reason, emission factors presented in these tables cannot be used to directly estimate net emissions from these sources. See detailed explanation of methodology above.

[1] Activity data for 2012 available from source.

[2] Ratios relating other factors for which activity data are available.

Table A-131: U.S. Production Sector CH_4 Content in Natural Gas by NEMS Region (General Sources)

	U.S. Region						
Year	North East	Midcontinent	Rocky Mountain	South West	West Coast	Gulf Coast	Lower 48 States
1990	84.0%	78.3%	67.4%	64.4%	75.3%	79.8%	n/a
1991	83.8%	78.7%	69.3%	67.1%	78.1%	80.1%	n/a
1992	83.5%	79.1%	71.2%	74.4%	80.8%	82.7%	n/a
1993	82.9%	79.9%	73.4%	76.1%	83.6%	84.1%	n/a
1994	82.0%	80.7%	75.5%	77.4%	86.4%	85.6%	n/a
1995	81.5%	81.6%	77.6%	79.0%	89.1%	87.2%	n/a
1996	81.2%	82.6%	80.5%	80.5%	91.9%	88.7%	84.2%
1997	80.3%	82.5%	80.4%	80.5%	91.9%	88.6%	84.1%
1998	81.0%	82.5%	80.5%	80.5%	91.9%	88.6%	84.2%
1999	80.5%	82.5%	80.4%	80.5%	91.9%	88.7%	84.2%
2000	80.8%	82.5%	80.2%	80.5%	91.9%	88.7%	84.0%
2001	80.3%	82.5%	79.5%	80.5%	91.9%	88.7%	83.8%
2002	80.4%	82.5%	79.3%	80.5%	91.9%	88.6%	83.5%
2003	76.4%	82.6%	79.1%	80.5%	91.9%	88.6%	83.2%
2004	80.4%	82.7%	79.0%	80.5%	91.9%	88.6%	83.4%
2005	80.1%	82.7%	79.0%	80.5%	91.9%	88.6%	83.4%
2006	79.5%	83.0%	79.0%	80.5%	91.9%	88.6%	83.5%
2007	85.8%	82.7%	77.5%	80.5%	91.9%	88.6%	83.9%
2008	86.0%	82.7%	77.7%	80.5%	91.9%	88.5%	83.9%
2009	85.1%	82.7%	77.5%	80.5%	91.9%	88.5%	83.6%
2010	84.3%	82.8%	77.4%	80.5%	91.9%	88.3%	83.4%
2011	85.2%	82.6%	77.5%	80.5%	91.9%	88.2%	83.3%
2012	85.2%	82.6%	77.5%	80.5%	91.9%	88.2%	83.3%

Table A-132: U.S. Production Sector CH_4 Content in Natural Gas by NEMS Region (Gas Wells Without Hydraulic Fracturing)

	U.S. Region						
Year	North East	Midcontinent	Rocky Mountain	South West	West Coast	Gulf Coast	Lower 48 States
1990	84.0%	78.3%	67.4%	64.4%	75.3%	79.8%	n/a
1991	83.8%	78.7%	69.3%	67.1%	78.1%	80.1%	n/a
1992	83.5%	79.1%	71.2%	74.4%	80.8%	82.7%	n/a
1993	82.9%	79.9%	73.4%	76.1%	83.6%	84.1%	n/a
1994	82.0%	80.7%	75.5%	77.4%	86.4%	85.6%	n/a
1995	81.5%	81.6%	77.6%	79.0%	89.1%	87.2%	n/a
1996	81.2%	82.5%	79.6%	80.5%	91.9%	88.6%	84.0%
1997	80.5%	82.5%	79.5%	80.5%	91.9%	88.6%	83.9%
1998	81.2%	82.5%	79.6%	80.5%	91.9%	88.6%	84.0%
1999	80.7%	82.5%	79.5%	80.5%	91.9%	88.7%	83.9%
2000	81.0%	82.5%	79.2%	80.5%	91.9%	88.7%	83.8%
2001	80.4%	82.5%	78.3%	80.5%	91.9%	88.6%	83.5%
2002	80.5%	82.5%	78.1%	80.5%	91.9%	88.6%	83.2%
2003	76.5%	82.6%	77.9%	80.5%	91.9%	88.6%	82.9%
2004	80.5%	82.6%	77.8%	80.5%	91.9%	88.6%	83.1%
2005	80.3%	82.7%	77.7%	80.5%	91.9%	88.6%	83.1%
2006	79.6%	83.0%	77.7%	80.5%	91.9%	88.6%	83.1%
2007	85.6%	82.7%	75.8%	80.5%	91.9%	88.6%	83.5%
2008	85.6%	82.7%	76.0%	80.5%	91.9%	88.5%	83.5%
2009	84.7%	82.7%	75.8%	80.5%	91.9%	88.5%	83.2%
2010	83.8%	82.8%	75.7%	80.5%	91.9%	88.3%	82.9%
2011	85.0%	82.6%	75.8%	80.5%	91.9%	88.2%	82.8%
2012	85.0%	82.6%	75.8%	80.5%	91.9%	88.2%	82.8%

Table A-133: U.S. Production Sector CH_4 Content in Natural Gas by NEMS Region (Gas Wells With Hydraulic Fracturing)

	U.S. Region						
Year	North East	Midcontinent	Rocky Mountain	South West	West Coast	Gulf Coast	Lower 48 States
1990	84.0%	78.3%	67.4%	64.4%	75.3%	79.8%	n/a
1991	83.8%	78.7%	69.3%	67.1%	78.1%	80.1%	n/a
1992	83.5%	79.1%	71.2%	74.4%	80.8%	82.7%	n/a

1993	82.9%	79.9%	73.4%	76.1%	83.6%	84.1%	n/a
1994	82.0%	80.7%	75.5%	77.4%	86.4%	85.6%	n/a
1995	81.5%	81.6%	77.6%	79.0%	89.1%	87.2%	n/a
1996	83.2%	92.6%	74.4%	80.5%	91.9%	88.7%	82.1%
1997	83.1%	92.6%	74.9%	80.5%	91.9%	88.6%	82.1%
1998	83.1%	92.6%	75.5%	80.5%	91.9%	88.6%	82.3%
1999	83.1%	92.6%	75.4%	80.5%	91.9%	88.7%	82.0%
2000	83.0%	92.6%	76.4%	80.5%	91.9%	88.7%	82.5%
2001	83.0%	92.6%	78.9%	80.5%	91.9%	88.7%	83.6%
2002	83.0%	92.6%	80.5%	80.5%	91.9%	88.6%	84.4%
2003	83.1%	92.6%	81.4%	80.5%	91.9%	88.6%	84.9%
2004	83.0%	92.6%	81.7%	80.5%	91.9%	88.6%	85.2%
2005	83.0%	92.6%	82.0%	80.5%	91.9%	88.6%	85.3%
2006	83.0%	92.6%	82.3%	80.5%	91.9%	88.6%	85.5%
2007	83.5%	92.6%	86.5%	80.5%	91.9%	88.6%	88.7%
2008	84.1%	92.6%	86.2%	80.5%	91.9%	88.5%	88.4%
2009	84.1%	92.6%	86.8%	80.5%	91.9%	88.5%	88.7%
2010	84.3%	92.6%	86.8%	80.5%	91.9%	88.3%	89.0%
2011	83.6%	92.6%	87.9%	80.5%	91.9%	88.2%	89.4%
2012	83.6%	92.6%	88.1%	80.5%	91.9%	88.2%	89.5%

Table A-134: Key Activity Data Drivers

Variable	Units	1990	1995	2000	2005	2011	2012
Transmission Pipelines Length	**miles**	**291,925**	**296,947**	**298,957**	**300,468**	**304,954**	**303,126**
Wells							
NE—Associated Gas Wells[a,1]	# wells	25,835	23,534	24,522	29,536	37,115	38,770
NE—Non-associated Gas Wells[a,1]	# wells	64,134	90,350	103,760	129,765	156,158	158,974
MC—Associated Gas Wells[a,1]	# wells	37,568	32,508	28,605	27,496	27,926	27,470
MC—Non-associated Gas Wells[a,1]	# wells	65,317	69,934	75,000	89,817	108,559	108,052
RM—Associated Gas Wells[a,1]	# wells	18,565	19,852	19,332	21,032	29,243	32,598
RM—Non-associated Gas Wells[a,1]	# wells	26,036	31,574	42,324	66,975	84,349	83,420
SW—Associated Gas Wells[a,1]	# wells	233,236	175,589	156,865	148,294	154,144	155,119
SW—Non-associated Gas Wells[a,1]	# wells	22,146	22,653	25,472	33,600	41,380	41,487
WC—Associated Gas Wells[a,1]	# wells	17,130	14,035	15,775	18,765	29,318	29,726
WC—Non-associated Gas Wells[a,1]	# wells	2,041	1,929	2,029	2,030	2,152	2,094
GC—Associated Gas Wells[a,1]	# wells	101,151	69,484	50,089	41,391	38,319	39,709
GC—Non-associated Gas Wells[a,1]	# wells	36,692	38,279	43,419	57,415	76,828	76,886
Platforms[aa]							
Gulf of Mexico and Pacific OCS Off-shore Platforms[b,2]	# platforms	3,941	3,978	4,016	3,909	3,432	3,432
GoM and Pacific OCS Deep Water Platforms[b,2]	# platforms	17	23	38	59	70	70
Gas Plants[c,1]	**# gas plants**	**761**	**675**	**585**	**566**	**606**	**606**
Distribution Services	**# of services**	**47,883,083**	**54,644,033**	**56,761,042**	**61,832,574**	**64,731,838**	**65,024,491**
Steel—Unprotected[d,1]	# of services	7,633,526	6,151,653	5,675,520	5,507,356	4,140,616	3,916,353
Steel—Protected[d,1]	# of services	19,781,581	21,002,455	17,855,560	16,529,118	15,267,357	14,951,473
Plastic[d,1]	# of services	18,879,865	26,044,545	31,795,871	38,549,089	44,269,061	45,147,410
Copper[d,1]	# of services	1,588,111	1,445,380	1,434,091	1,247,011	1,054,804	1,009,255
Distribution Mains	**miles**	**944,157**	**1,001,706**	**1,048,485**	**1,162,560**	**1,231,045**	**1,244,470**
Cast Iron[d,1]	miles	58,292	50,625	44,750	39,645	33,586	32,418
Steel—Unprotected[d,1]	miles	108,941	94,058	82,800	72,458	64,092	63,727
Steel—Protected[d,1]	miles	465,538	503,288	471,510	490,156	488,265	487,225
Plastic[d,1]	miles	311,386	353,735	449,425	560,301	645,102	661,100

[aa] Number of platforms include both oil and gas platforms

[a] DI Desktop (2014)

[b] Bureau of Ocean Energy Management, Regulation and Enforcement (2011)

[c] Oil and Gas Journal

[d] Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS) (2013)

[1] Activity data for 2012 available from source.

[2] 2011 activity data are used to determine some or all of the 2012 activity (to be updated).

Table A-135: CH_4 Reductions Derived from the Natural Gas STAR Program (Gg)

Process	1990	1995	2000	2005	2011	2012
Production	**(9.0)**	**(86.4)**	**(302.5)**	**(579.0)**	**(1,603.0)**	**(1,635.7)**
Pipeline Leaks	(0.0)	(0.0)	-	(2.4)	-	-
Pneumatic Device Vents	(5.4)	(25.8)	(118.4)	(226.4)	(806.7)	(873.1)
Chemical Injection Pumps	-	-	-	(0.0)	(2.1)	(2.8)
Gas Engines	(0.0)	(13.8)	(53.2)	(97.9)	(137.2)	(139.9)
Compressor Starts	-	(0.0)	(0.1)	(0.2)	(0.5)	(0.5)
Other Production	(3.5)	(46.8)	(130.9)	(251.9)	(656.5)	(619.3)
Processing	**(1.5)**	**(21.8)**	**(42.8)**	**(155.5)**	**(140.4)**	**(140.4)**
Fugitives Reciprocating Compressors	-	-	-	-	-	-
Gas Engines	-	-	(0.1)	(1.1)	(6.1)	(6.1)
AGR Vents	-	-	-	-	-	-
Dehydrator Vents	(1.3)	-	(0.2)	(2.1)	(9.3)	(9.3)
Other Processing	(0.2)	(21.8)	(42.6)	(152.2)	(125.0)	(125.0)
Transmission and Storage	**-**	**(107.7)**	**(264.0)**	**(506.8)**	**(355.0)**	**(390.1)**
Fugitives Reciprocating Compressors	-	(0.6)	-	(0.2)	(0.2)	(0.7)
Engines	-	(12.5)	(49.3)	(83.2)	(121.6)	(123.9)
Pneumatic Device Vents (Transmission)	-	(5.4)	(8.9)	(10.5)	(13.0)	(14.1)
Pipeline Vents	-	(36.3)	(33.3)	(124.9)	(58.9)	(100.1)
Other Transmission	-	(52.8)	(172.5)	(288.1)	(161.3)	(151.2)
Distribution	**-**	**(19.7)**	**(29.9)**	**(48.4)**	**(58.1)**	**(44.8)**
Fugitives Cast Iron	-	(0.0)	(0.1)	(0.1)	(0.1)	(0.1)
Mishaps (Dig-ins)	-	-	-	(0.3)	(4.7)	(0.7)
Other Distribution	-	(19.7)	(29.9)	(48.0)	(53.3)	(44.0)
Total	**(10.5)**	**(235.6)**	**(639.3)**	**(1,289.6)**	**(2,156.5)**	**(2,211.0)**

These reductions will not match the Natural Gas STAR program reductions. These numbers are adjusted for reductions prior to the 1992 base year, and do not include a "sunsetting" period. Totals may not sum due to independent rounding.

This table presents aggregate Gas STAR reduction data for each natural gas system stage, and also presents reductions for select technologies for which disaggregated Gas STAR data can be matched to an Inventory source category. In general, the Inventory uses aggregated Gas STAR reductions by natural gas system stage (i.e., production, processing, transmission and storage, and distribution). In some cases, emissions reductions reported to Gas STAR have been matched to potential emissions calculated in the Inventory, to provide a net emissions number for specific emissions sources. This table presents sources for which Gas STAR reductions can be matched to Inventory emissions sources. Net emissions values for these sources are presented in Table A-141. Some reported Gas STAR reduction activities are cross-cutting and cover multiple Inventory sources. It is not possible to attribute those reductions to specific Inventory source categories, and they are included in the "Other" category.

Table A-136: CH_4 Reductions Derived from Regulations (Gg)

Process	1990	1995	2000	2005	2011	2012
Production	**NA**	**NA**	**(45.5)**	**(62.7)**	**(99.0)**	**(99.2)**
Dehydrator vents (NESHAP)	NA	NA	(23.8)	(30.8)	(38.7)	(38.9)
Condensate tanks (NESHAP)	NA	NA	(21.7)	(31.9)	(60.3)	(60.3)
Processing	**(0.0)**	**(0.0)**	**(12.9)**	**(12.1)**	**(15.5)**	**(16.3)**
Dehydrator vents (NESHAP)	(0.0)	(0.0)	(12.9)	(12.1)	(15.5)	(16.3)
Transmission and Storage	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**
Distribution	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**
Total	**(0.0)**	**(0.0)**	**(58.4)**	**(74.8)**	**(114.6)**	**(115.5)**

NA Not applicable

Note: Totals may not sum due to independent rounding.

Table A-137: National CH_4 Potential Emission Estimates from the Natural Gas Production Stage, and Reductions from the Natural Gas STAR Program and Regulations (Gg)

Activity	1990	1995	2000	2005	2011	2012
Normal Fugitives						
Associated Gas Wells	IE	IE	IE	IE	IE	IE
Non-Associated Gas Wells (less wells with hydraulic fracturing)	10.8	12.7	13.7	15.8	18.3	18.3
Gas Wells with Hydraulic Fracturing	8.5	12.1	15.9	26.0	35.5	35.4
Field Separation Equipment						
Heaters	12.9	15.9	19.4	26.9	33.5	33.3

Activity	**1990**	**1995**	**2000**	**2005**	**2011**	**2012**
Separators	40.9	50.1	60.7	84.0	107.1	106.7
Dehydrators	14.4	17.2	20.0	26.3	32.9	32.8
Meters/ Piping	46.2	54.1	63.4	84.9	106.5	106.2
Gathering Compressors						
Small Reciprocating Compressors	33.2	39.1	45.2	58.1	71.3	70.9
Large Reciprocating Compressors	7.3	8.9	10.0	11.7	15.4	15.4
Large Reciprocating Stations	0.5	0.6	0.7	0.8	1.0	1.0
Pipeline Leaks	89.1	105.7	118.8	146.3	175.5	175.5
Vented and Combusted						
Drilling, Well Completion, and Well Workover						
Gas Well Completions without Hydraulic Fracturing	0.0	0.0	0.0	0.0	0.0	0.0
Gas Well Workovers without Hydraulic Fracturing	0.3	0.4	0.4	0.5	0.5	0.5
Hydraulic Fracturing Completions and Workovers that vent	219.1	198.9	304.8	415.3	191.8	192.2
Flared Hydraulic Fracturing Completions and Workovers	3.0	2.7	4.1	7.3	6.9	3.9
Hydraulic Fracturing Completions and Workovers with RECs	-	-	-	5.4	11.6	10.2
Hydraulic Fracturing Completions and Workovers with RECs that flare	-	-	-	3.6	7.8	10.9
Well Drilling	0.7	0.5	1.0	1.6	1.0	1.0
Produced Water from Coal Bed Methane Wells						
Powder River	0.0	1.5	31.4	50.0	47.2	47.2
Black Warrior	2.7	6.3	6.8	9.9	12.7	12.8
Normal Operations						
Pneumatic Device Vents	529.6	642.7	745.8	973.5	1,209.0	1,207.5
Chemical Injection Pumps	30.0	35.8	42.1	55.5	67.8	67.3
Kimray Pumps	165.9	206.0	238.0	307.6	387.1	388.4
Dehydrator Vents	51.7	64.2	74.2	95.9	120.7	121.1
Condensate Tank Vents						
Condensate Tanks without Control Device	77.7	58.1	67.5	99.3	187.7	187.7
Condensate Tanks with Control Device	15.5	11.6	13.5	19.9	37.5	37.5
Compressor Exhaust Vented						
Gas Engines	117.6	139.0	162.0	213.9	266.8	265.7
Liquids Unloading						
Liquids Unloading (with plunger lifts)	-	16.5	37.8	72.2	118.8	118.9
Liquids Unloading (without plunger lifts)	893.0	912.5	831.3	678.5	154.4	154.7
Blowdowns						
Vessel Blowdown	0.3	0.4	0.4	0.6	0.7	0.7
Pipeline Blowdown	1.4	1.7	1.9	2.3	2.8	2.8
Compressor Blowdown	1.3	1.5	1.7	2.2	2.8	2.7
Compressor Starts	2.9	3.4	3.9	5.0	6.2	6.1
Upsets						
Pressure Relief Valves	0.3	0.4	0.4	0.6	0.7	0.7
Mishaps	0.8	0.9	1.0	1.3	1.5	1.5
Offshore						
Offshore Water Gas Platforms (Gulf of Mexico & Pacific)	290.5	307.3	323.7	321.8	266.1	266.1
Deepwater Gas Platforms (Gulf of Mexico & Pacific)	5.2	7.4	12.8	20.4	23.0	23.0
Regulatory Reductions	**-**	**-**	**(45.5)**	**(62.7)**	**(99.0)**	**(99.2)**
Voluntary Reductions	**(9.0)**	**(86.4)**	**(302.5)**	**(579.0)**	**(1,603.0)**	**(1,635.7)**
Total Reductions	**(9.0)**	**(86.4)**	**(348.0)**	**(641.6)**	**(1,702.0)**	**(1,734.8)**
Total Potential Emissions	**2,673.4**	**2,936.2**	**3,274.5**	**3,847.6**	**3,729.8**	**3,726.6**
Total Net Emissions	**2,664.5**	**2,849.8**	**2,926.5**	**3,206.0**	**2,027.7**	**1,991.8**

Note 1: Totals may not sum due to independent rounding.

IE: Included Elsewhere. These emissions are included in the Petroleum Systems estimates.

Table A-138: Potential CH_4 Emission Estimates from the Natural Gas Processing Plants, and Reductions from the Natural Gas STAR Program and Regulations (Gg)

Activity	1990	1995	2000	2005	2011	2012
Normal Fugitives						
Plants	42.3	37.5	32.5	31.5	33.7	33.7
Reciprocating Compressors	324.9	338.4	349.5	327.9	420.9	442.6
Centrifugal Compressors (wet seals)	240.3	248.6	251.3	229.2	236.1	237.7
Centrifugal Compressors (dry seals)	-	0.8	3.5	6.5	36.8	43.9
Vented and Combusted	-					
Normal Operations						
Compressor Exhaust						
Gas Engines	137.1	142.8	147.5	138.3	177.6	186.8
Gas Turbines	3.9	4.0	4.2	3.9	5.0	5.3
AGR Vents	16.5	14.6	12.7	12.3	13.1	13.1
Kimray Pumps	3.7	3.8	4.0	3.7	4.8	5.0
Dehydrator Vents	22.7	23.6	24.4	22.9	29.4	30.9
Pneumatic Devices	2.4	2.1	1.9	1.8	1.9	1.9
Routine Maintenance						
Blowdowns/Venting	59.5	52.8	45.7	44.3	47.4	47.4
Regulatory Reductions	**-**	**-**	**(12.9)**	**(12.1)**	**(15.5)**	**(16.3)**
Voluntary Reductions	**(1.5)**	**(21.8)**	**(42.8)**	**(155.5)**	**(140.4)**	**(140.4)**
Total Reductions	**(1.5)**	**(21.8)**	**(55.7)**	**(167.6)**	**(155.9)**	**(156.8)**
Total Potential Emissions	**853.2**	**869.2**	**877.1**	**822.2**	**1,006.6**	**1,048.3**
Total Net Emissions	**851.8**	**847.3**	**821.3**	**654.6**	**850.7**	**891.5**

Note 1: Totals may not sum due to independent rounding.

Table A-139: Potential CH_4 Emission Estimates from the Natural Gas Transmission and Storage, and Reductions from the Natural Gas STAR Program and Regulations (Gg)

Activity	1990	1995	2000	2005	2011	2012
Fugitives						
Pipelines Leaks	3.2	3.2	3.3	3.3	3.3	3.3
Compressor Stations (Transmission)						
Station	106.9	108.8	109.5	110.1	111.7	111.0
Recip Compressor	744.7	757.5	762.7	766.5	778.0	773.3
Centrifugal Compressor (wet seals)	246.7	249.7	243.0	234.1	234.4	232.8
Centrifugal Compressor (dry seals)	-	0.8	6.2	12.7	15.0	15.0
Compressor Stations (Storage)						
Station	54.6	60.4	62.2	60.1	58.7	52.0
Recip Compressor	157.8	174.3	179.6	173.5	169.4	150.2
Centrifugal Compressor (wet seals)	33.2	36.6	34.4	30.9	26.5	22.3
Centrifugal Compressor (dry seals)	-	0.1	2.5	4.1	6.5	6.5
Wells (Storage)	13.6	15.0	15.4	14.9	14.6	12.9
M&R (Trans. Co. Interconnect)	72.8	74.0	74.5	74.9	76.0	75.6
M&R (Farm Taps + Direct Sales)	16.9	17.2	17.3	17.4	17.7	17.5
Vented and Combusted						
Normal Operation						
Dehydrator Vents (Transmission)	2.0	2.0	2.0	2.1	2.1	2.1
Dehydrator Vents (Storage)	4.2	4.7	4.8	4.6	4.5	4.0
Compressor Exhaust						
Engines (Transmission)	176.9	204.9	215.3	203.1	225.0	235.3
Turbines (Transmission)	1.0	1.2	1.2	1.2	1.3	1.3
Engines (Storage)	21.3	23.5	24.2	23.4	22.9	20.3
Turbines (Storage)	0.2	0.2	0.2	0.2	0.2	0.2
Generators (Engines)	8.7	10.0	10.5	9.9	11.0	11.5
Generators (Turbines)	0.0	0.0	0.0	0.0	0.0	0.0
Pneumatic Devices Transmission + Storage						
Pneumatic Devices Trans	213.1	216.7	218.2	219.3	222.6	221.3
Pneumatic Devices Storage	44.4	49.1	50.6	48.8	47.7	42.3
Routine Maintenance/Upsets						

Activity	1990	1995	2000	2005	2011	2012
Pipeline Venting	178.0	181.0	182.2	183.2	185.9	184.8
Station venting Transmission + Storage						
Station Venting Transmission	145.5	148.0	149.0	149.7	152.0	151.1
Station Venting Storage	30.3	33.5	34.5	33.4	32.6	28.9
LNG Storage						
LNG Stations	9.2	9.8	10.3	10.6	10.6	10.6
LNG Reciprocating Compressors	34.5	36.7	38.8	40.1	40.1	40.1
LNG Centrifugal Compressors	11.8	12.5	13.3	13.8	13.8	13.8
LNG Compressor Exhaust						
LNG Engines	2.6	2.6	2.7	2.7	2.7	2.7
LNG Turbines	0.0	0.0	0.0	0.0	0.0	0.0
LNG Station Venting	5.1	5.4	5.7	5.9	5.9	5.9
LNG Import Terminals						
LNG Stations	0.2	0.2	0.2	0.4	1.2	1.2
LNG Reciprocating Compressors	1.0	1.0	1.0	2.0	5.6	5.6
LNG Centrifugal Compressors	0.3	0.3	0.3	0.5	1.4	1.4
LNG Compressor Exhaust						
LNG Engines	1.7	0.5	4.4	12.2	6.9	3.6
LNG Turbines	0.0	0.0	0.0	0.1	0.0	0.0
LNG Station Venting	0.1	0.1	0.1	0.2	0.6	0.6
Regulatory Reductions	**-**	**-**	**-**	**-**	**-**	**-**
Voluntary Reductions	**-**	**(107.7)**	**(264.0)**	**(506.8)**	**(355.0)**	**(390.1)**
Total Reductions	**-**	**(107.7)**	**(264.0)**	**(506.8)**	**(355.0)**	**(390.1)**
Total Potential Emissions	**2,342.6**	**2,441.6**	**2,480.4**	**2,470.0**	**2,508.2**	**2,461.1**
Total Net Emissions	**2,342.6**	**2,333.9**	**2,216.4**	**1,963.2**	**2,153.1**	**2,071.0**

Note: Totals may not sum due to independent rounding.

Table A-140: Potential CH$_4$ Emission Estimates from the Natural Gas Distribution Stage, and Reductions from the Natural Gas STAR Program, and Regulations (Gg)

Activity	1990	1995	2000	2005	2011	2012
Pipeline Leaks						
Mains—Cast Iron	268.0	232.7	205.7	182.3	154.4	149.0
Mains—Unprotected steel	231.2	199.6	175.7	153.8	136.0	135.2
Mains—Protected steel	27.5	29.7	27.9	29.0	28.8	28.8
Mains—Plastic	59.4	67.5	85.8	106.9	123.1	126.2
Services—Unprotected steel	250.0	201.5	185.9	180.4	135.6	128.3
Services Protected steel	67.2	71.4	60.7	56.2	51.9	50.8
Services—Plastic	3.4	4.7	5.7	6.9	7.9	8.1
Services—Copper	7.8	7.1	7.0	6.1	5.2	4.9
Meter/Regulator (City Gates)						
M&R >300	110.4	122.0	125.6	121.4	118.5	105.1
M&R 100-300	214.2	236.6	243.8	235.5	230.0	203.9
M&R <100	5.2	5.7	5.9	5.7	5.5	4.9
Reg >300	108.7	120.1	123.7	119.5	116.7	103.5
R-Vault >300	0.5	0.6	0.6	0.6	0.6	0.5
Reg 100-300	82.3	90.9	93.6	90.4	88.3	78.3
R-Vault 100-300	0.2	0.2	0.2	0.2	0.2	0.2
Reg 40-100	6.3	7.0	7.2	7.0	6.8	6.0
R-Vault 40-100	0.5	0.5	0.5	0.5	0.5	0.4
Reg <40	0.3	0.4	0.4	0.4	0.4	0.3
Customer Meters						
Residential	103.5	114.3	117.7	113.7	111.1	98.5
Commercial/Industry	4.0	4.8	4.7	3.9	4.1	4.1
Routine Maintenance						
Pressure Relief Valve Releases	0.9	1.0	1.0	1.1	1.2	1.2
Pipeline Blowdown	2.4	2.6	2.7	2.6	2.6	2.3
Upsets						
Mishaps (Dig-ins)	37.2	41.1	42.3	40.9	39.9	35.4
Regulatory Reductions	**-**	**-**	**-**	**-**	**-**	**-**

Activity	1990	1995	2000	2005	2011	2012
Voluntary Reductions	**-**	**(19.7)**	**(29.9)**	**(48.4)**	**(58.1)**	**(44.8)**
Total Reductions	**-**	**(19.7)**	**(29.9)**	**(48.4)**	**(58.1)**	**(44.8)**
Total Potential Emissions	**1,591.1**	**1,561.9**	**1,524.3**	**1,464.9**	**1,369.4**	**1,276.1**
Total Net Emissions	**1,591.1**	**1,542.1**	**1,494.4**	**1,416.5**	**1,311.3**	**1,231.3**

Note: Totals may not sum due to independent rounding.

Table A-141: Net emissions for select sources (Gg)

Stage/Activity	1990	1995	2000	2005	2011	2012
Production	**2,664.5**	**2,849.8**	**2,926.5**	**3,206.0**	**2,027.7**	**1,991.8**
Hydraulic Fracturing Completions and Workov	222.1	201.6	308.9	434.1	218.1	217.1
Liquids Unloading	893.0	929.0	869.1	750.7	273.2	273.6
Dehydrator Vents	51.7	64.2	50.4	65.1	82.0	82.2
Condensate Tanks	93.2	69.7	59.3	87.3	164.9	164.9
Pipeline Leaks	89.1	105.7	118.8	143.8	175.5	175.5
Pneumatic Device Vents	524.2	616.9	627.4	747.1	402.2	334.4
Chemical Injection Pumps	30.0	35.8	42.1	55.5	65.7	64.6
Gas Engines	117.6	125.3	108.8	116.0	129.6	125.8
Compressor Starts	2.9	3.4	3.8	4.8	5.6	5.6
Other Production	640.7	698.2	737.9	801.5	510.8	548.1
Processing	**851.8**	**847.3**	**821.3**	**654.6**	**850.7**	**891.5**
Fugitives Reciprocating Compressors	324.9	338.4	349.5	327.9	420.9	442.6
Gas Engines	137.1	142.8	147.4	137.2	171.5	180.7
AGR Vents	16.5	14.6	12.7	12.3	13.1	13.1
Dehydrator Vents	21.3	23.6	11.3	8.6	4.5	5.2
Other Processing	351.9	327.9	300.5	168.6	240.8	249.9
Transmission and Storage	**2,342.6**	**2,333.9**	**2,216.4**	**1,963.2**	**2,153.1**	**2071.0**
Fugitives Reciprocating Compressors	744.7	756.9	762.7	766.3	777.7	772.6
Engines	176.9	192.4	166.0	119.9	103.4	111.4
Pneumatic Device Vents (Transmission)	213.1	211.4	209.3	208.9	209.6	207.2
Pipeline Vents	178.0	144.7	149.0	58.3	126.9	84.7
Other Transmission	1,030.0	1,028.6	929.4	809.8	935.4	895.2
Distribution	**1,591.1**	**1,542.1**	**1,494.4**	**1,416.5**	**1,311.3**	**1231.3**
Fugitives Cast Iron	268	233	206	182	154	149
Mishaps (Dig-ins)	37	41	42	41	35	34.7
Other Distribution	1,286	1,268	1,246	1,194	1,222	1,048
Total	**7,450**	**7,573**	**7,459**	**7,240**	**6,343**	**6,186**

Note: This table presents net emissions for each natural gas system stage, and also presents net emissions for select emissions sources for which disaggregated Gas STAR data and/or regulation reduction data can be matched to an Inventory source category, and sources for which emissions are calculated using net emission factors. In general, the Inventory uses aggregated Gas STAR reductions by natural gas system stage (i.e., production, processing, transmission and storage, and distribution). In some cases, emissions reductions reported to Gas STAR have been matched to potential emissions calculated in the Inventory, to provide a net emissions number for specific emissions sources. This table presents sources for which Gas STAR reductions and/or regulatory reductions can be matched to Inventory emissions sources. Net emission values presented here were calculated by deducting the voluntary reductions (Table A-135) and the regulatory reductions (Table A-136) from the potential emissions values in Table A-137 throughTable A-140. Some reported Gas STAR reduction activities are cross-cutting and cover multiple Inventory sources. It is not possible to attribute those reductions to specific Inventory source categories, and they are included in the "Other" category.

Table A-142: U.S. Production Sector CO_2 Content in Natural Gas by NEMS Region and Formation Type for all years

	U.S. Region						
Formation Types	**North East**	**Midcontinent**	**Gulf Coast**	**South West**	**Rocky Mountain**	**West Coast**	**Lower-48 States**
Conventional	0.92%	0.79%	2.17%	3.81%	7.95%	0.16%	3.41%
Non-conventional*	7.42%	0.31%	0.23%	NA	0.64%	NA	4.83%
All types	3.04%	0.79%	2.17%	3.81%	7.58%	0.16%	3.45%

Source: GRI-01/0136 GTI's Gas Resource Database: Unconventional Natural Gas and Gas Composition Databases. Second Edition. August, 2001

*In GTI, this refers to shale, coal bed methane, and tight geologic formations.

Table A- 143: CO_2 Emission Estimates from the Natural Gas Production Stage (Gg)

Activity	1990	1995	2000	2005	2011	2012
Normal Fugitives						
Gas Wells						
Non-Associated Gas Wells	1.0	1.1	1.1	1.3	1.5	1.5

Activity	1990	1995	2000	2005	2011	2012
Gas Wells with Hydraulic Fracturing	0.4	0.5	0.7	0.9	1.0	1.0
Field Separation Equipment						
Heaters	1.9	2.2	2.8	4.2	5.3	5.2
Separators	5.9	6.6	8.2	12.0	15.3	15.2
Dehydrators	1.4	1.6	2.0	2.8	3.6	3.5
Meters/ Piping	6.3	6.8	8.3	11.9	15.0	14.9
Gathering Compressors						
Small Reciprocating Compressors	3.0	3.3	4.1	6.0	7.5	7.4
Large Reciprocating Compressors	0.8	0.9	1.0	1.3	1.7	1.7
Large Reciprocating Stations	0.1	0.1	0.1	0.1	0.1	0.1
Pipeline Leaks	9.8	10.9	12.6	16.7	20.1	20.1
Vented and Combusted						
Drilling, Well Completion, and Well Workover						
Gas Well Completions without Hydraulic Fracturing[b]	0.0	0.0	0.0	0.0	0.0	0.0
Gas Well Workovers without Hydraulic Fracturing[b]	0.0	0.0	0.0	0.0	0.0	0.0
Gas Well Completions with Hydraulic Fracturing	106.8	96.5	211.3	296.6	242.5	208.9
Gas Well Workovers with Hydraulic Fracturing	16.9	21.5	28.2	43.1	44.1	26.1
Well Drilling	0.1	0.1	0.1	0.2	0.1	0.1
Produced Water from Coal Bed Methane Wells						
Powder River[1]	NE	NE	NE	NE	NE	NE
Black Warrior[a]	NE	NE	NE	NE	NE	NE
Normal Operations						
Pneumatic Device Vents	52.4	61.5	75.4	108.0	134.8	134.3
Chemical Injection Pumps	3.1	3.6	4.6	6.8	8.6	8.5
Kimray Pumps	16.2	19.7	23.6	32.7	40.6	40.7
Dehydrator Vents	5.1	6.1	7.4	10.2	12.7	12.7
Condensate Tank Vents						
Condensate Tanks without Control Device	10.3	8.8	9.3	10.3	15.7	15.7
Condensate Tanks with Control Device	2.1	1.8	1.9	2.1	3.1	3.1
Compressor Exhaust Vented						
Gas Engines[a]	NE	NE	NE	NE	NE	NE
Liquids Unloading						
Liquids Unloading – Vent with plunger Lifts	-	1.7	4.2	8.9	14.7	14.6
Liquids Unloading – Vent without plunger Lifts	266.2	244.3	220.8	183.2	27.2	27.1
Blowdowns						
Vessel Blowdowns[b]	0.0	0.0	0.0	0.1	0.1	0.1
Pipeline Blowdowns	0.2	0.2	0.2	0.3	0.3	0.3
Compressor Blowdowns	0.1	0.1	0.2	0.2	0.3	0.3
Compressor Starts	0.3	0.3	0.4	0.5	0.6	0.6
Upsets						
Pressure Relief Valves[b]	0.0	0.0	0.0	0.1	0.1	0.1
Mishaps	0.1	0.1	0.1	0.1	0.2	0.2
Flaring Emissions – Onshore Production and Processing	9,092.7	17,167.8	5,525.0	7,193.0	12,534.7	12,738.8
Offshore						
Shallow water Gas Platforms (Gulf of Mexico & Pacific)	1.5	1.6	1.6	1.6	1.4	1.4
Deepwater Gas Platforms (Gulf of Mexico & Pacific) [b]	0.0	0.0	0.1	0.1	0.1	0.1
Flaring Emissions – Offshore	230.4	197.2	204.3	180.7	358.0	358.0
Total	**9,834.9**	**17,866.9**	**6,359.7**	**8,135.8**	**13,511.1**	**13,662.6**

[a] Energy use CO_2 emissions not estimated to avoid double counting. NE = not estimated.
[b] Emissions are not actually 0, but too small to show at this level of precision.
Note: Totals may not sum due to independent rounding.

Table A-144: CO_2 Emission Estimates from the Natural Gas Processing Stage (Gg)

Activity	1990	1995	2000	2005	2011	2012
Normal Fugitives						
Plants – Before CO_2 removal	2.6	2.3	2.0	1.9	2.0	2.0
Plants – After CO_2 removal	0.6	0.5	0.4	0.4	0.5	0.5
Reciprocating Compressors – Before CO_2 removal	19.7	20.5	21.2	19.8	25.5	26.8
Reciprocating Compressors – After CO_2 removal	4.4	4.5	4.7	4.4	5.7	5.9
Centrifugal Compressors (wet seals) – Before CO_2 removal	14.5	15.0	15.2	13.9	14.3	14.4
Centrifugal Compressors (wet seals) – After CO_2 removal	3.2	3.3	3.4	3.1	3.2	3.2
Centrifugal Compressors (dry seals) – Before CO_2 removal	-	0.0	0.2	0.4	2.2	2.7
Centrifugal Compressors (dry seals) – After CO_2 removal	-	0.0	0.0	0.1	0.5	0.6
Vented and Combusted						
Normal Operations						
Compressor Exhaust						
Gas Engines[a]	NE	NE	NE	NE	NE	NE
Gas Turbines[a]	NE	NE	NE	NE	NE	NE
AGR Vents	27,708.2	24,576.9	23,288.2	21,694.3	21,403.6	21,403.6
Kimray Pumps	0.4	0.4	0.4	0.4	0.5	0.5
Dehydrator Vents	2.4	2.5	2.6	2.4	3.1	3.3
Pneumatic Devices	0.3	0.3	0.2	0.2	0.2	0.2
Routine Maintenance						
Blowdowns/Venting	6.4	5.6	4.9	4.7	5.1	5.1
Total	**27,762.6**	**24,632.0**	**23,343.5**	**21,746.1**	**21,466.3**	**21,468.8**

[a] Energy use CO_2 emissions not estimated to avoid double counting. NE = not estimated.
Note: Totals may not sum due to independent rounding.

Table A-145: CO_2 Emission Estimates from the Natural Gas Transmission and Storage Stage (Gg)

Activity	1990	1995	2000	2005	2011	2012
Fugitives						
Pipelines Leaks	0.1	0.1	0.1	0.1	0.1	0.1
Compressor Stations (Transmission)						
Station	3.1	3.1	3.2	3.2	3.2	3.2
Reciprocating Compressor	21.5	21.9	22.0	22.1	22.4	22.3
Centrifugal Compressor (wet seals)	7.1	7.2	7.0	6.8	6.8	6.7
Centrifugal Compressor (dry seals)	-	0.0	0.2	0.4	0.4	0.4
Compressor Stations (Storage)						
Station	1.6	1.7	1.8	1.7	1.7	1.5
Reciprocating Compressor	4.6	5.0	5.2	5.0	4.9	4.3
Centrifugal Compressor (wet seals)	1.0	1.1	1.0	0.9	0.8	0.6
Centrifugal Compressor (dry seals)	-	0.0	0.1	0.1	0.2	0.2
Wells (Storage)	0.4	0.4	0.4	0.4	0.4	0.4
M&R (Trans. Co. Interconnect)	2.1	2.1	2.1	2.2	2.2	2.2
M&R (Farm Taps + Direct Sales)	0.5	0.5	0.5	0.5	0.5	0.5
Vented and Combusted						
Normal Operation						
Dehydrator Vents (Transmission)	0.1	0.1	0.1	0.1	0.1	0.1
Dehydrator Vents (Storage)	0.1	0.1	0.1	0.1	0.1	0.1
Compressor Exhaust						
Engines (Transmission)[1]	NE	NE	NE	NE	NE	NE
Turbines (Transmission)[1]	NE	NE	NE	NE	NE	NE
Engines (Storage)[1]	NE	NE	NE	NE	NE	NE
Turbines (Storage)[1]	NE	NE	NE	NE	NE	NE
Generators (Engines)[1]	NE	NE	NE	NE	NE	NE
Generators (Turbines)[1]	NE	NE	NE	NE	NE	NE

Activity	1990	1995	2000	2005	2011	2012
Pneumatic Devices Transmission + Storage						
Pneumatic Devices Transmission	6.1	6.3	6.3	6.3	6.4	6.4
Pneumatic Devices Storage	1.3	1.4	1.5	1.4	1.4	1.2
Routine Maintenance/Upsets						
Pipeline Venting	5.1	5.2	5.3	5.3	5.4	5.3
Station Venting Transmission + Storage						
Station Venting Transmission	4.2	4.3	4.3	4.3	4.4	4.4
Station Venting Storage	0.9	1.0	1.0	1.0	0.9	0.8
LNG Storage						
LNG Stations	0.3	0.3	0.3	0.4	0.4	0.4
LNG Reciprocating Compressors	1.2	1.2	1.3	1.3	1.3	1.3
LNG Centrifugal Compressors	0.4	0.4	0.4	0.5	0.5	0.5
LNG Compressor Exhaust						
LNG Engines[1]	NE	NE	NE	NE	NE	NE
LNG Turbines[1]	NE	NE	NE	NE	NE	NE
LNG Station Venting	0.2	0.2	0.2	0.2	0.2	0.2
LNG Import Terminals						
LNG Stations	0.0	0.0	0.0	0.0	0.0	0.0
LNG Reciprocating Compressors	0.0	0.0	0.0	0.1	0.2	0.2
LNG Centrifugal Compressors	0.0	0.0	0.0	0.0	0.0	0.0
LNG Compressor Exhaust						
LNG Engines[1]	NE	NE	NE	NE	NE	NE
LNG Turbines[1]	NE	NE	NE	NE	NE	NE
LNG Station Venting[2]	0.0	0.0	0.0	0.0	0.0	0.0
Total	**61.7**	**63.7**	**64.4**	**64.3**	**64.9**	**63.4**

[a] Energy use CO_2 emissions not estimated to avoid double counting. NE = not estimated.

[2] Emissions are not actually 0, but too small to show at this level of precision.

Note: Totals may not sum due to independent rounding.

Table A-146: CO_2 Emission Estimates from the Natural Gas Distribution Stage (Gg)

Activity	1990	1995	2000	2005	2011	2012
Pipeline Leaks						
Mains—Cast Iron	7.7	6.7	5.9	5.3	4.5	4.3
Mains—Unprotected steel	6.7	5.8	5.1	4.4	3.9	3.9
Mains—Protected steel	0.8	0.9	0.8	0.8	0.8	0.8
Mains—Plastic	1.7	1.9	2.5	3.1	3.6	3.6
Total Pipeline Miles						
Services—Unprotected steel	7.2	5.8	5.4	5.2	3.9	3.7
Services Protected steel	1.9	2.1	1.8	1.6	1.5	1.5
Services—Plastic	0.1	0.1	0.2	0.2	0.2	0.2
Services—Copper	0.2	0.2	0.2	0.2	0.1	0.1
Meter/Regulator (City Gates)						
M&R >300	3.2	3.5	3.6	3.5	3.4	3.0
M&R 100-300	6.2	6.8	7.0	6.8	6.6	5.9
M&R <100	0.1	0.2	0.2	0.2	0.2	0.1
Reg >300	3.1	3.5	3.6	3.4	3.4	3.0
R-Vault >300	0.0	0.0	0.0	0.0	0.0	0.0
Reg 100-300	2.4	2.6	2.7	2.6	2.5	2.3
R-Vault 100-300	0.0	0.0	0.0	0.0	0.0	0.0
Reg 40-100	0.2	0.2	0.2	0.2	0.2	0.2
R-Vault 40-100	0.0	0.0	0.0	0.0	0.0	0.0
Reg <40	0.0	0.0	0.0	0.0	0.0	0.0
Customer Meters						
Residential	3.0	3.3	3.4	3.3	3.2	2.8
Commercial/Industry	0.1	0.1	0.1	0.1	0.1	0.1
Routine Maintenance						
Pressure Relief Valve Releases	0.0	0.0	0.0	0.0	0.0	0.0
Pipeline Blowdown	0.1	0.1	0.1	0.1	0.1	0.1
Upsets						
Mishaps (Dig-ins)	1.1	1.2	1.2	1.2	1.2	1.0

Activity	1990	1995	2000	2005	2011	2012
Total	**45.9**	**45.1**	**44.0**	**42.3**	**39.5**	**36.8**

Note: Totals may not sum due to independent rounding.

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3.6. Methodology for Estimating CH_4 and CO_2 Emissions from Petroleum Systems

The methodology for estimating CH_4 and non-combustion CO_2 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* (EPA/GRI 1996). Sixty-four activities that emit CH_4 and thirty activities that emit non-combustion CO_2 from petroleum systems were examined from these reports. Most of the activities analyzed involve crude oil production field operations, which accounted for over 98 percent of total oil industry CH_4 emissions. Crude transportation and refining accounted for the remaining CH_4 emissions of less than 0.4 and less than 1.3 percent, respectively. Non-combustion CO_2 emissions were analyzed for production operations and asphalt blowing in refining operations. Non-combustion CO_2 emissions from transportation operations are not included because they are negligible. The following steps were taken to estimate CH_4 and CO_2 emissions from petroleum systems.

Step 1: Calculate Potential Methane and Carbon Dioxide

Activity Data

Activity levels change from year to year. Some data changes 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 the rate and number of facilities.

For most sources, activity data for 1995 found in EPA/GRI 1996 are extrapolated to other years using publicly-available data sources. For the remaining sources, the activity data are obtained directly from publicly available data.

For both sets of data, a determination was made on a case-by-case basis as to which measure of petroleum industry activity best reflects the change in annual activity. Publicly-reported data from the Bureau of Ocean Energy Management (BOEM), Energy Information Administration (EIA), American Petroleum Institute (API), the Oil & Gas Journal (O&GJ), the Interstate Oil and Gas Compact Commission (IOGCC), and the U.S Army Corps of Engineers (USACE) were used to extrapolate the activity data from the base year to each year between 1990 and 2012. Data used include total domestic crude oil production, number of domestic crude oil wells, total imports and exports of crude oil, total petroleum refinery crude runs, and number of oil-producing offshore platforms. The activity data for the total crude transported in the transportation sector is not available. In this case, all the crude oil that was transported was assumed to go to refineries. Therefore, the activity data for the refining sector was used also for the transportation sector. In the few cases where no data was located, oil industry data based on expert judgment was used. In the case of non-combustion CO_2 emission sources, the activity factors are the same as for CH_4 emission sources.

Potential methane factors and emission factors

The CH_4 emission factors for the majority of the activities are taken from the 1999 EPA draft report, which contained the most recent and comprehensive determination of CH_4 emission factors for the 64 CH_4-emitting activities in the oil industry at that time. Emission factors for pneumatic devices in the production sector were recalculated in 2002 using emissions data in the EPA/GRI 1996c study. The gas engine emission factor is taken from the EPA/GRI 1996b study. The oil tank venting emission factor is taken from the API E&P Tank Calc weighted average for API gravity less than 45 API degrees with the distribution of gravities taken from a sample of production data from the HPDI database. Offshore emissions from shallow water and deep water oil platforms are taken from analysis of the Gulf-wide Offshore Activity Data System (GOADS) report (EPA 2005, BOEMRE 2004). The emission factors were assumed to be representative of emissions from each source type over the period 1990 through 2012. Therefore, the same emission factors are used for each year throughout this period.

The CO_2 emission factors were derived from the corresponding source CH_4 emission factors. The amount of CO_2 in the crude oil stream changes as it passes through various equipment in petroleum production operations. As a result, four distinct stages/streams with varying CO_2 contents exist. The four streams that are used to estimate the emissions factors are the associated gas stream separated from crude oil, hydrocarbons flashed out from crude oil (such as in storage tanks), whole crude oil itself when it leaks downstream, and gas emissions from offshore oil platforms. The standard approach used to estimate CO_2 emission factors was to use the existing CH_4 emissions factors and multiply them by a conversion factor, which is the ratio of CO_2 content to methane content for the particular stream. Ratios of CO_2 to CH_4 volume in emissions are presented in Table A-151. The two exceptions are the emissions factor for storage tanks, which is estimated using API E&P Tank Calc simulation runs of tank emissions for crude oil of different gravities less than 45 API degrees; and the emissions factor for uncontrolled asphalt blowing, which is estimated using the data and methods provided by API (2009).

Step 2: Compile Reductions Data

The methane emissions calculated in Step 1 above generally represent expected emissions from an activity in the absence of emissions controls, and do not take into account any use of technologies or practices that reduce emissions. To take into account use of such technologies, data were collected on voluntary reductions. Voluntary reductions included in the Petroleum Sector calculations were those reported to Gas STAR for the following activities: Artificial lift: gas lift, Artificial lift: use compression, Artificial lift: use pumping unit, Consolidate crude oil prod and water storage tanks, Lower heater-treater temperature, Re-inject gas for enhanced oil recovery, Re-inject gas into crude, and Route casinghead gas to VRU or compressor.

Industry partners report CH_4 emission reductions by project to the Natural Gas STAR Program. The reductions from the implementation of specific technologies and practices are calculated by the reporting partners using actual measurement data or equipment-specific emission factors. The reductions undergo quality assurance and quality control checks to identify errors, inconsistencies, or irregular data before being incorporated into the Inventory. The Inventory uses aggregated Gas STAR reductions for the petroleum sector.

Step 3: Calculate Net Methane and Carbon Dioxide Emissions for Each Activity for Each Year

Annual CH_4 emissions from each of the 64 petroleum system activities and CO_2 emissions from the 30 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 CH_4 and CO_2 emissions, respectively. Gas Star reductions data is summed for each year and deducted from the potential CH_4 calculated in Step 1 to estimate net CH_4 emissions for the Inventory.

Table A-147, Table A-148, Table A-149, and Table A-152 provide 2012 activity data, emission factors, and emission estimates and Table A-150 and Table A-153 provide a summary of emission estimates for the years 1990, 1995, 2000, and 2005 through 2012. Table A-151 provides the CO_2 content in natural gas for equipment in different crude streams to estimate CO_2 emission factors using CH_4 emission factors.

The tables provide references for emission factors and activity data in footnotes (the lettered footnotes). The tables also provide information on which method was used for supplying activity data for 2012 (the numbered footnotes).

<u>Key to table notations on methods for supplying activity data for 2012 for all tables</u>:

1. Ratios relating other factors for which activity data are available. For example, EPA (1996) found that the number of heater treaters (a source of CH_4 emissions) is related to both number of producing wells and annual production. To estimate the activity data for heater treaters, reported statistics for wells and production were used, along with the ratios developed for EPA (1996).
2. Activity data for 2012 available from source.
3. Activity data was held constant from 1990 through 2012 based on EPA (1999).
4. 2009, 2010, or 2011 activity data are used to determine some or all of the 2012 activity data.

Table A-147: 2012 CH_4 Emissions from Petroleum Production Field Operations

	2012 EPA Inventory Values					
Activity/Equipment	**Emission Factor**		**Activity Data**		**Emissions (Bcf/yr)**	**Emissions (Gg/yr)**
Vented Emissions					**71.623**	**1,377.373**
Oil Tanks	7.39	scf of CH_4/bbl crude[a]	1,878	MMbbl/yr (non stripper wells)[b,c,d,1,4]	13.890	267.121
Pneumatic Devices, High Bleed	330	scfd CH_4/device[f]	145,179	No. of high-bleed devices[c,e,g,1]	17.508	336.692
Pneumatic Devices, Low Bleed	52	scfd CH_4/device[f]	269,618	No. of low-bleed devices[c,e,g,1]	5.117	98.411
Chemical Injection Pumps	248	scfd CH_4/pump[h]	28,702	No. of pumps[g,i,p1]	2.599	49.973
Vessel Blowdowns	78	scfy CH_4/vessel[h]	189,710	No. of vessels[c,g,i,1]	0.015	0.285
Compressor Blowdowns	3,775	scf/yr of CH_4/compressor[h]	2,582	No. of compressors[c,g,i,1]	0.010	0.187
Compressor Starts	8,443	scf/yr of CH_4/compressor[h]	2,582	No. of compressors[c,g,i,1]	0.022	0.419
Stripper wells	2,345	scf/yr of CH_4/stripper well[f]	315,213	No. of stripper wells vented[f,1,4]	0.739	14.21

	2012 EPA Inventory Values					
Activity/Equipment	**Emission Factor**		**Activity Data**		**Emissions (Bcf/yr)**	**Emissions (Gg/yr)**
Well Completion Venting	733	scf/completion[h]	15,753	Oil well completions[c,2]	0.012	0.222
Well Workovers	96	scf CH_4/workover[i]	40,200	Oil well workovers[g,i,1]	0.004	0.074
Pipeline Pigging	2.40	scfd of CH_4/pig station[j]	0	No. of crude pig stations[e,3]	-	-
Offshore Platforms, Shallow water Oil, fugitive, vented and combusted	54,795	scfd CH_4/platform[k]	1,447	No. of shallow water oil platforms[l,4]	28.930	556.353
Offshore Platforms, Deepwater oil, fugitive, vented and combusted	260,274	scfd CH_4/platform[k]	29	No. of deep water oil platforms[l,4]	2.778	53.419
Fugitive Emissions					**2.669**	**51.330**
Oil Wellheads (heavy crude)	0.13	scfd/well[e,m]	15,565	No. of hvy. crude wells[d,g,i,1,4]	0.001	0.014
Oil Wellheads (light crude)	16.6	scfd/well[e,m]	205,222	No. of lt. crude wells[d,g,i,1,4]	1.246	23.956
Separators (heavy crude)	0.15	scfd CH_4/separator[e,m]	11,142	No. of hvy. crude seps.[c,g,i,1]	0.001	0.012
Separators (light crude)	14	scfd CH_4/separator[e,m]	101,402	No. of lt. crude seps.[c,g,i,1]	0.513	9.860
Heater/Treaters (light crude)	19	scfd CH_4/heater[e,m]	77,166	No. of heater treaters[c,g,i,1]	0.541	10.396
Headers (heavy crude)	0.08	scfd CH_4/header[e,m]	13,982	No. of hvy. crude hdrs.[g,i,1]	0.000*	0.008
Headers (light crude)	11	scfd CH_4/header[e,m]	43,344	No. of lt. crude hdrs.[g,i,1]	0.172	3.303
Floating Roof Tanks	338,306	scf CH_4/floating roof tank/yr[m,n]	24	No. of floating roof tanks[e,3]	0.008	0.159
Compressors	100	scfd CH_4/compressor[e]	2,582	No. of compressors[c,g,i,1]	0.094	1.812
Large Compressors	16,360	scfd CH_4/compressor[e]	0	No. of large comprs.[e,3]	-	-
Sales Areas	41	scf CH_4/loading[e]	1,974,334	Loadings/year[c,1]	0.080	1.540
Pipelines	NE	scfd of CH_4/mile of pipeline	14,077	Miles of gathering line[o,2]	NE	NE
Well Drilling	NE	scfd of CH_4/oil well drilled	17,774	No. of oil wells drilled[c,2]	NE	NE
Battery Pumps	0.24	scfd of CH_4/pump[m]	160,800	No. of battery pumps[g,e,1]	0.014	0.271
Combustion Emissions					**5.188**	**99.765**
Gas Engines	0.24	scf CH_4/HP-hr[h]	16,264	MMHP-hr[c,g,i,1]	3.903	75.063
Heaters	0.52	scf CH_4/bbl[n]	2,369.6	MMbbl/yr[c,2]	1.235	23.746
Well Drilling	2,453	scf CH_4/well drilled[m]	17,774	Oil wells drilled[c,2]	0.044	0.838
Flares	20	scf CH_4/Mcf flared[j]	305,587	Mcf flared/yr [b,c,d,1,4]	0.006	0.118
Process Upset Emissions					**0.155**	**2.980**
Pressure Relief Valves	35	scf/yr/PR valve	197,931	No. of PR valves	0.007	0.132
Well Blowouts Onshore	2.5	MMscf/blowout	59.2	No. of blowouts/yr	0.148	2.848
				Voluntary Reductions	**2.34**	**45**
				Total Potential Emissions	**79.64**	**1,531.447**
				Total Net Emissions	**77.29**	**1,486**

[a] TankCALC
[b] EPA / ICF International (1999)
[c] Energy Information Administration (EIA) Monthly Energy Review
[d] Interstate Oil & Gas Compact Commission (IOGCC) Marginal Wells Report
[e] Consensus of Industrial Review Panel
[f] Expert Judgment
[g] EIA Annual Energy Review
[h] Gas Research Institute (GRI) / EPA (1996)
[i] Radian (1999)
[j] Canadian Association of Petroleum Producers (CAPP) (1992)
[k] Adapted from the Minerals Management Service (MMS) Gulfwide Offshore Activities Data System (GOADS) by ICF (2005)
[l] Bureau of Ocean Energy Management (BOEM)
[m] American Petroleum Institute (API) (1996)
[n] EPA, AP 42 Compilation of Air Pollutant Emission Factors
[o] Oil and Gas Journal (OGJ) Petroleum Economics Issue
[p] Percentage of chemical injection pumps (CIPs) that are gas-driven was determined through based on an estimate provided in 1997 by Ron Rayman. From Dresser Texsteam, a major manufacturer of CIPs at the time.
- Zero Emissions
* Emissions are not actually 0, but too small to show at this level of precision.

Table A-148: 2012 CH_4 Emissions from Petroleum Transportation

Activity/Equipment	Emission Factor	Units	Activity Factor	Units	Emissions (Bcf/yr)	Emissions (Gg/yr)
Vented Emissions					**0.256**	**4.928**
Tanks	0.021	scf CH_4/yr/bbl of crude delivered to refineries[a]	5,490	MMbbl crude feed/yr[b,2]	0.113	2.175
Truck Loading	0.520	scf CH_4/yr/bbl of crude transported by truck[c]	131.3	MMbbl crude trans. by truck[d,2]	0.068	1.313
Marine Loading	2.544	scf CH_4/1000 gal crude marine loadings[c]	17,518,599	1,000 gal/yr loaded[e,1,4]	0.045	0.857
Rail Loading	0.520	scf CH_4/yr/bbl of crude transported by rail[c]	30.1	MMbbl Crude by rail/yr[d,2]	0.016	0.301
Pump Station Maintenance	36.80	scf CH_4/station/yr[f]	513	No. of pump stations[g,1]	0.000*	0.000*
Pipeline Pigging	39	scfd of CH_4/pig station[h]	1,027	No. of pig stations[g,1]	0.015	0.281
Fugitive Emissions					**0.050**	**0.959**
Pump Stations	25	scf CH_4/mile/yr[f]	51,349	No. of miles of crude p/l[g,2]	0.001	0.025
Pipelines	NE	scf CH_4/bbl crude transported by pipeline[f]	7,471	MMbbl crude piped[g,2]	NE	NE
Floating Roof Tanks	58,965	scf CH_4/floating roof tank/yr[i]	824	No. of floating roof tanks[3]	0.049	0.934
Combustion Emissions					**NE**	**NE**
Pump Engine Drivers	0.24	scf CH_4/hp-hr[j]	NE	No. of hp-hrs	NE	NE
Heaters	0.521	scf CH_4/bbl burned[k]	NE	No. of bbl Burned	NE	NE
Total					**0.306**	**5.887**

[a] API (1992)
[b] Energy Information Administration (EIA) Petroleum Supply Annual, Volume 1.
[c] EPA, AP 42 Compilation of Air Pollutant Emission Factors
[d] EIA Refinery Capacity Report
[e] EIA Monthly Energy Review
[f] Radian (1996)
[g] OGJ Petroleum Economics Issue
[h] CAPP (1992)
[i] API TANK
[j] GRI / EPA (1996)
[k] EPA / ICF International (1999)
* Emissions are not actually 0, but too small to show at this level of precision.
NE: Not estimated for lack of data

Table A-149: 2012 CH_4 Emissions from Petroleum Refining

	2012 EPA Inventory Values					
Activity/Equipment	**Emission Factor**		**Activity Factor**		**Emissions (Bcf/yr)**	**Emissions (Gg/yr)**
Vented Emissions					**0.798**	**15.349**
Tanks	20.6	scf CH_4/Mbbl[a]	1,930	Mbbl/calendar day heavy crude feed[b,c,1]	0.015	0.279
System Blowdowns	137	scf CH_4/Mbbl[c]	15,040	Mbbl/calendar day refinery feed[b,2]	0.751	14.443
Asphalt Blowing	2,555	scf CH_4/Mbbl[c]	35	Mbbl/calendar day production[b,2]	0.033	0.627
Fugitive Emissions					**0.087**	**1.672**
Fuel Gas System	439	Mscf CH_4/refinery/yr[a]	144	Refineries[d,2]	0.063	1.216
Floating Roof Tanks	587	scf CH_4/floating roof tank/yr[e]	767	No. of floating roof tanks[3]	0.000*	0.009
Wastewater Treating	1.88	scf CH_4/Mbbl[c]	15,040	Mbbl/calendar day refinery feed[b,2]	0.010	0.199
Cooling Towers	2.36	scf CH_4/Mbbl[c]	15,040	Mbbl/calendar day refinery feed[b,2]	0.013	0.249
Combustion Emissions					**0.096**	**1.842**
Atmospheric Distillation	3.61	scf CH_4/Mbbl[c]	15,362	Mbbl/calendar day refinery	0.020	0.389

Activity/Equipment	Emission Factor		Activity Factor		Emissions (Bcf/yr)	Emissions (Gg/yr)
	2012 EPA Inventory Values					
				feed[d,2]		
Vacuum Distillation	3.61	scf CH_4/Mbbl[c]	7,133	Mbbl/calendar day feed[f,1]	0.009	0.181
Thermal Operations	6.01	scf CH_4/Mbbl[c]	2,295	Mbbl/calendar day feed [f,1]	0.005	0.097
Catalytic Cracking	5.17	scf CH_4/Mbbl[c]	5,034	Mbbl/calendar day feed [f,1]	0.010	0.183
Catalytic Reforming	7.22	scf CH_4/Mbbl[c]	3,112	Mbbl/calendar day feed [f,1]	0.008	0.158
Catalytic Hydrocracking	7.22	scf CH_4/Mbbl[c]	1,548	Mbbl/calendar day feed [f,1]	0.004	0.078
Hydrorefining	2.17	scf CH_4/Mbbl[c]	2,268	Mbbl/calendar day feed [f,1]	0.002	0.034
Hydrotreating	6.50	scf CH_4/Mbbl[c]	10,401	Mbbl/calendar day feed [f,1]	0.025	0.474
Alkylation/Polymerization	12.6	scf CH_4/Mbbl[c]	1,088	Mbbl/calendar day feed [f,1]	0.005	0.096
Aromatics/Isomeration	1.80	scf CH_4/Mbbl[c]	1,011	Mbbl/calendar day feed [f,1]	0.001	0.013
Lube Oil Processing	0.00	scf CH_4/Mbbl[c]	171	Mbbl/calendar day feed [f,1]	0.000	0.000
Engines	0.006	scf CH_4/hp-hr[g]	1,084	MMhp-hr/yr[f,1]	0.006	0.119
Flares	0.189	scf CH_4/Mbbl[c,e]	15,040	Mbbl/calendar day refinery feed[b,2]	0.001	0.020
Total					**0.981**	**18.864**

[a] API (1992)
[b] EIA Petroleum Supply Annual, Volume 1.
[c] Radian (1996)
[d] EIA Petroleum Navigator
[e] EPA, AP 42 Compilation of Air Pollutant Emission Factors
[f] OGJ Refinery Worldwide Report
[g] GRI / EPA (1996)
* Emissions are not actually 0, but too small to show at this level of precision.

Table A-150: Summary of CH_4 Emissions from Petroleum Systems (Gg)

Activity	1990	1995	2000	2007	2008	2009	2010	2011	2012
Production Field Operations	**1,680**	**1,581**	**1,488**	**1,415**	**1,425**	**1,432**	**1,443**	**1,474**	**1,531**
Pneumatic device venting	489	463	428	398	416	419	416	428	435
Tank venting	250	226	214	193	185	202	211	222	267
Combustion & process upsets	115	106	97	90	94	94	95	98	103
Misc. venting & fugitives	799	762	726	714	706	694	700	702	703
Wellhead fugitives	26	25	22	20	24	23	22	24	24
Crude Oil Transportation	**7**	**6**	**5**	**5**	**5**	**5**	**5**	**5**	**6**
Refining	**18**	**18**	**19**	**19**	**19**	**18**	**19**	**19**	**19**
Voluntary Reductions	**0.2**	**1.4**	**17**	**64**	**77**	**67**	**60**	**45**	**45**
Total Potential Emissions	**1,704**	**1,605**	**1,513**	**1,439**	**1,449**	**1,455**	**1,467**	**1,498**	**1,556**
Total Net Emissions	**1,704**	**1,604**	**1,496**	**1,376**	**1,372**	**1,388**	**1,407**	**1,453**	**1,511**

Note: Totals may not sum due to independent rounding.

Table A-151: Ratios of CO_2 to CH_4 Volume in Emissions from Petroleum Production Field Operations

	Whole Crude, Post-Separator	Associated Gas	Tank Flash Gas	Offshore
Ratio %CO_2 / %CH_4	0.052	0.020	0.017	0.004

Table A-152: 2012 CO_2 Emissions from Petroleum Production Field Operations and Petroleum Refining

Activity/Equipment	Emission Factor		Activity Factor		Emissions (Bcf/yr)	Emissions (Gg/yr)
	2012 EPA Inventory Values					
Vented Emissions					**7.363**	**389.364**
Oil Tanks	3.53	scf of CO_2/bbl crude[a]	1,878	MMbbl/yr (non stripper wells)[b,c,d,1,4]	6.627	350.477
Pneumatic Devices, High Bleed	6.704	scfd CO_2/device[f]	145,179	No. of high-bleed devices[c,e,g,1]	0.355	18.787

Activity/Equipment	2012 EPA Inventory Values					
	Emission Factor		Activity Factor		Emissions (Bcf/yr)	Emissions (Gg/yr)
Pneumatic Devices, Low Bleed	1.055	scfd CO_2/device[f]	269,618	No. of low-bleed devices[c,e,g,1]	0.104	5.491
Chemical Injection Pumps	5.033	scfd CO_2/pump[h]	28,702	No. of pumps[g,i,1]	0.053	2.788
Vessel Blowdowns	1.583	scfy CO_2/vessel[h]	189,710	No. of vessels[c,g,i,1]	0.000*	0.016
Compressor Blowdowns	77	scf/yr of CO_2/compressor[h]	2,582	No. of compressors[c,g,i,1]	0.000*	0.010
Compressor Starts	171	scf/yr of CO_2/compressor[h]	2,582	No. of compressors[c,g,i,1]	0.000*	0.023
Stripper wells	48	scf/yr of CO_2/stripper well[f]	315,213	No. of stripper wells vented[f,1,4]	0.015	0.793
Well Completion Venting	14.87	scf/completion[h]	15,753	Oil well completions[c,2]	0.000*	0.012
Well Workovers	1.95	scf CO_2/workover[i]	40,200	Oil well workovers[g,i,1]	0.000*	0.004
Pipeline Pigging	NE	scfd of CO_2/pig station	NE	No. of crude pig stations	NE	NE
Offshore Platforms, Shallow water Oil, fugitive, vented and combusted	358	scfd CO_2/platform[k]	1,447	No. of shallow water oil platforms[l,4]	0.189	10.00
Offshore Platforms, Deepwater oil, fugitive, vented and combusted	1,701	scfd CO_2/platform[k]	29	No. of deep water oil platforms[l,4]	0.018	0.960
Fugitive Emissions					**0.055**	**2.929**
Oil Wellheads (heavy crude)	0.003	scfd/well[e,m]	15,565	No. of hvy. crude wells[d,g,i,1,4]	0.000*	0.001
Oil Wellheads (light crude)	0.337	scfd/well[e,m]	205,222	No. of lt. crude wells[d,g,i,1,4]	0.025	1.337
Separators (heavy crude)	0.003	scfd CO_2/separator[e,m]	11,142	No. of hvy. crude seps.[c,g,i,1]	0.000*	0.001
Separators (light crude)	0.281	scfd CO_2/separator[e,m]	101,402	No. of lt. crude seps.[c,g,i,1]	0.010	0.550
Heater/Treaters (light crude)	0.319	scfd CO_2/heater[e,m]	77,166	No. of heater treaters[c,g,i,1]	0.009	0.475
Headers (heavy crude)	0.002	scfd CO_2/header[e,m]	13,982	No. of hvy. crude hdrs.[g,i,1]	0.000*	0.000*
Headers (light crude)	0.220	scfd CO_2/header[e,m]	43,344	No. of lt. crude hdrs.[g,i,1]	0.003	0.184
Floating Roof Tanks	17,490	scf CO_2/floating roof tank/yr[m,n]	24	No. of floating roof tanks[e,3]	0.000*	0.023
Compressors	2.029	scfd CO_2/compressor[e]	2,582	No. of compressors[c,g,i,1]	0.002	0.101
Large Compressors	332	scfd CO_2/compressor[e]	0	No. of large comprs.[e,3]	0.000	0.000
Sales Areas	2.096	scf CO_2/loading[e]	1,974,334	Loadings/year[c,1]	0.004	0.219
Pipelines	NE	scfd of CO_2/mile of pipeline	14,077	Miles of gathering line[o,2]	NE	NE
Well Drilling	NE	scfd of CO_2/oil well drilled	17,774	No. of oil wells drilled[c,2]	NE	NE
Battery Pumps	0.012	scfd of CO_2/pump[m]	160,800	No. of battery pumps[g,e,1]	0.001	0.039
Process Upset Emissions					**0.003**	**0.178**
Pressure Relief Valves	1.794	scf/yr/PR valve[h]	197,931	No. of PR valves[c,e,1]	0.000*	0.019
Well Blowouts Onshore	0.051	MMscf/blowout[e]	59.0	No. of blowouts/yr[c,e,1]	0.003	0.159
Refining Emissions					**0.265**	**14.00**
Asphalt Blowing†	20,736	scf CO_2/Mbbl[m]	35	Mbbl/calendar day production[p,2]	0.265	13.998
Total					**7.686**	**406.468**

[a] TankCALC
[b] EPA / ICF International (1999)
[c] EIA Monthly Energy Review
[d] IOGCC Marginal Wells Report
[e] Consensus of Industrial Review Panel
[f] Expert Judgement
[g] EIA Annual Energy Review
[h] GRI / EPA (1996)
[i] Radian (1996)
[j] CAPP (1992)
[k] Adapted from the MMS GOADS by ICF (2005)
[l] BOEM
[m] API (1996)

[n] EPA, AP 42 Compilation of Air Pollutant Emission Factors
[o] OGJ Petroleum Economics Issue
[p] EIA Petroleum Supply Annual, Volume 1
* Emissions are not actually 0, but too small to show at this level of precision.
† Asphalt Blowing emissions are the only significant vented emissions from the refining sector; other sources are too small to show at this level of precision.
NE: Not estimated for lack of data
Energy use CO_2 emissions not estimated to avoid double counting with fossil fuel combustion

Table A-153: Summary of CO_2 Emissions from Petroleum Systems (Gg)

Activity	1990	1995	2000	2007	2008	2009	2010	2011	2012
Production Field Operations	**376**	**341**	**323**	**293**	**284**	**306**	**317**	**332**	**392**
Pneumatic device venting	27	26	24	22	23	23	23	24	24
Tank venting	328	296	281	253	243	265	276	291	350
Misc. venting & fugitives	18	18	17	16	16	16	16	16	16
Wellhead fugitives	1	1	1	1	1	1	1	1	1
Refining	**18**	**19**	**21**	**18**	**16**	**14**	**15**	**15**	**14**
Asphalt Blowing	18	19	21	18	16	14	15	15	14
Total	**394**	**360**	**344**	**311**	**300**	**320**	**332**	**347**	**406**

3.7. Methodology for Estimating CO_2, N_2O and CH_4 Emissions from the Incineration of Waste

Emissions of CO_2 from the incineration of waste include CO_2 generated by the incineration of plastics, synthetic rubber and synthetic fibers in municipal solid waste (MSW), and incineration of tires (which are composed in part of synthetic rubber and C black) in a variety of other combustion facilities (e.g., cement kilns). Incineration of waste also results in emissions of N_2O and CH_4. The methodology for calculating emissions from each of these waste incineration sources is described in this Annex.

CO_2 from Plastics Incineration

In the *Municipal Solid Waste Generation, Recycling, and Disposal in the United States: Facts and Figures* reports (EPA 1999 through 2003, 2005 through 2014), the flows of plastics in the U.S. waste stream are reported for seven resin categories. For 2012, the quantity generated, recovered, and discarded for each resin is shown in Table A-154. The data set for 1990 through 2012 is incomplete, and several assumptions were employed to bridge the data gaps. The EPA reports do not provide estimates for individual materials landfilled and incinerated, although they do provide such an estimate for the waste stream as a whole. To estimate the quantity of plastics landfilled and incinerated, total discards were apportioned based on the proportions of landfilling and incineration for the entire U.S. waste stream for each year in the time series according to *Biocycle's State of Garbage in America* (van Haaren et al. 2010). For those years when distribution by resin category was not reported (1990 through 1994), total values were apportioned according to 1995 (the closest year) distribution ratios. Generation and recovery figures for 2002 and 2004 were linearly interpolated between surrounding years' data.

Table A-154: 2012 Plastics in the Municipal Solid Waste Stream by Resin (Gg)

Waste Pathway	PET	HDPE	PVC	LDPE/ LLDPE	PP	PS	Other	Total
Generation	4,101	5,017	789	6,668	6,523	2,032	3,629	**28,758**
Recovery	798	517	0	354	36	18	816	**2,540**
Discard	3,302	4,500	789	6,314	6,486	2,014	2,812	**26,218**
Landfill	3,011	4,103	720	5,757	5,915	1,836	2,564	**23,907**
Combustion	291	397	70	557	572	178	248	**2,311**
Recovery*	19%	10%	0%	5%	1%	1%	23%	**9%**
Discard*	81%	90%	100%	95%	99%	99%	78%	**91%**
Landfill*	73%	82%	91%	86%	91%	90%	71%	**83%**
Combustion*	7%	8%	9%	8%	9%	9%	7%	**8%**

*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 CO_2 emissions were calculated as the product of plastic combusted, C content, and fraction oxidized (see Table A-155). The C 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 A-155: 2012 Plastics Incinerated (Gg), Carbon Content (%), Fraction Oxidized (%) and Carbon Incinerated (Gg)

Factor	PET	HDPE	PVC	LDPE/ LLDPE	PP	PS	Other	Total
Quantity Combusted	291	397	70	557	572	178	248	2,311
Carbon Content of Resin	63%	86%	38%	86%	86%	92%	66%	-
Fraction Oxidized	98%	98%	98%	98%	98%	98%	98%	-
Carbon in Resin Combusted	178	333	26	468	480	161	160	1,806
Emissions (Tg CO_2 Eq.)	**0.7**	**1.2**	**0.1**	**1.7**	**1.8**	**0.6**	**0.6**	**6.6**

[a] Weighted average of other plastics produced.

Note: Totals may not sum due to independent rounding.

CO_2 from Incineration of Synthetic Rubber and Carbon Black in Tires

Emissions from tire incineration require two pieces of information: the amount of tires incinerated and the C content of the tires. "U.S. Scrap Tire Management Summary 2005-2009" (RMA 2011) reports that 2,085 thousand of the 4,391 thousand tons of scrap tires generated in 2009 (approximately 47 percent of generation) were used for fuel purposes.

Using RMA's estimates of average tire composition and weight, the mass of synthetic rubber and C black in scrap tires was determined:

- Synthetic rubber in tires was estimated to be 90 percent C by weight, based on the weighted average C contents of the major elastomers used in new tire consumption.[60] Table A-156 shows consumption and C content of elastomers used for tires and other products in 2002, the most recent year for which data are available.
- C black is 100 percent C (Aslett Rubber Inc. n.d.).

Multiplying the mass of scrap tires incinerated by the total C content of the synthetic rubber, C black portions of scrap tires, and then by a 98 percent oxidation factor, yielded CO_2 emissions, as shown in Table A- 157. The disposal rate of rubber in tires (0.4 Tg C/yr) is smaller than the consumption rate for tires based on summing the elastomers listed in Table A-154 (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 may also reflect the lag time between consumption and disposal of tires. Tire production and fuel use for 1990 through 2009 were taken from RMA 2006, RMA 2009, RMA 2011; where data were not reported, they were linearly interpolated between bracketing years' data or, for the ends of time series, set equal to the closest year with reported data.

In 2009, RMA changed the reporting of scrap tire data from millions of tires to thousands of short tons of scrap tire. As a result, the average weight and percent of the market of light duty and commercial scrap tires was used to convert the previous years from millions of tires to thousands of short tons (STMC 1990 through 1997; RMA 2002 through 2006, 2012a).

Table A-156: Elastomers Consumed in 2002 (Gg)

Elastomer	Consumed	Carbon Content	Carbon Equivalent
Styrene butadiene rubber solid	**768**	**91%**	**700**
For Tires	660	91%	602
For Other Products*	108	91%	98
Polybutadiene	**583**	**89%**	**518**
For Tires	408	89%	363
For Other Products	175	89%	155
Ethylene Propylene	**301**	**86%**	**258**
For Tires	6	86%	5
For Other Products	295	86%	253
Polychloroprene	**54**	**59%**	**32**
For Tires	0	59%	0
For Other Products	54	59%	32
Nitrile butadiene rubber solid	**84**	**77%**	**65**
For Tires	1	77%	1
For Other Products	83	77%	64
Polyisoprene	**58**	**88%**	**51**
For Tires	48	88%	42
For Other Products	10	88%	9
Others	**367**	**88%**	**323**
For Tires	184	88%	161
For Other Products	184	88%	161
Total	**2,215**	**-**	**1,950**
For Tires	**1,307**	**-**	**1,174**

* Used to calculate C content of non-tire rubber products in municipal solid waste.
- Not applicable
Note: Totals may not sum due to independent rounding.

Table A- 157: Scrap Tire Constituents and CO_2 Emissions from Scrap Tire Incineration in 2012

Material	Weight of Material (Tg)	Fraction Oxidized	Carbon Content	Emissions (Tg CO_2 Eq.)
Synthetic Rubber	0.4	98%	90%	1.6
Carbon Black	0.5	98%	100%	1.9
Total	**1.0**	**-**	**-**	**3.5**

- Not applicable

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[60] The carbon content of tires (1,174 Gg C) divided by the mass of rubber in tires (1,307 Gg) equals 90 percent.

CO_2 from Incineration of Synthetic Rubber in Municipal Solid Waste

Similar to the methodology for scrap tires, CO_2 emissions from synthetic rubber in MSW were estimated by multiplying the amount of rubber incinerated by an average rubber C content. The amount of rubber discarded in the MSW stream was estimated from generation and recycling data[61] provided in the *Municipal Solid Waste Generation, Recycling, and Disposal in the United States: Facts and Figures* reports (EPA 1999 through 2003, 2005 through 2014) and unpublished backup data (Schneider 2007). 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. EPA (2014) did not report rubber found in the product category "containers and packaging;" however, containers and packaging from miscellaneous material types were reported for 2009 through 2012. As a result, EPA assumes that rubber containers and packaging are reported under the "miscellaneous" category; and therefore, the quantity reported for 2009 through 2012 were set equal to the quantity reported for 2008. Since there was negligible recovery for these product types, all the waste generated is considered to be discarded. Similar to the plastics method, discards were apportioned into landfilling and incineration based on their relative proportions, for each year, for the entire U.S. waste stream. The report aggregates rubber and leather in the MSW stream; an assumed synthetic rubber content of 70 percent was assigned to each product type, as shown in Table A-158.[62] A C content of 85 percent was assigned to synthetic rubber for all product types (based on the weighted average C content of rubber consumed for non-tire uses), and a 98 percent fraction oxidized was assumed.

Table A-158: Rubber and Leather in Municipal Solid Waste in 2012

Product Type	Incinerated (Gg)	Synthetic Rubber (%)	Carbon Content (%)	Fraction Oxidized (%)	Emissions (Tg CO_2 Eq.)
Durables (not Tires)	280	70%	85%	98%	0.9
Non-Durables	81	-	-	-	0.3
Clothing and Footwear	62	70%	85%	98%	0.2
Other Non-Durables	19	70%	85%	98%	0.1
Containers and Packaging	2	70%	85%	98%	0.0
Total	**363**	**-**	**-**	**-**	**1.1**

+ Less than 0.05 Tg CO_2 Eq.

- Not applicable.

CO_2 from Incineration of Synthetic Fibers

CO_2 emissions from synthetic fibers were estimated as the product of the amount of synthetic fiber discarded annually and the average C content of synthetic fiber. Fiber in the MSW stream was estimated from data provided in the *Municipal Solid Waste Generation, Recycling, and Disposal in the United States: Facts and Figures* reports (EPA 1999 through 2003, 2005 through 2014) for textiles. Production data for the synthetic fibers was based on data from the American Chemical Society (FEB 2009). The amount of synthetic fiber in MSW was estimated by subtracting (a) the amount recovered from (b) the waste generated (see Table A-159). As with the other materials in the MSW stream, discards were apportioned based on the annually variable proportions of landfilling and incineration for the entire U.S. waste stream, as found in van Haaren et al. (2010). 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 C content of 70 percent was assigned to synthetic fiber using the production-weighted average of the C contents of the four major fiber types (polyester, nylon, olefin, and acrylic) produced in 1999 (see Table A-160). The equation relating CO_2 emissions to the amount of textiles combusted is shown below.

$$\begin{gathered}CO_2 \text{ Emissions from the Incineration of Synthetic Fibers} = \text{Annual Textile Incineration (Gg)} \times \\ \text{(Percent of Total Fiber that is Synthetic)} \times \text{(Average C Content of Synthetic Fiber)} \times \\ (44\text{g } CO_2/12 \text{ g C})\end{gathered}$$

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[61] Discards = Generation minus recycling.

[62] As a sustainably harvested biogenic material, the incineration of leather is assumed to have no net CO_2 emissions.

Table A-159: Synthetic Textiles in MSW (Gg)

Year	Generation	Recovery	Discards	Incineration
1990	2,884	328	2,557	332
1995	3,674	447	3,227	442
1996	3,832	472	3,361	467
1997	4,090	526	3,564	458
1998	4,269	556	3,713	407
1999	4,498	611	3,887	406
2000	4,706	655	4,051	417
2001	4,870	715	4,155	432
2002	5,123	750	4,373	459
2003	5,297	774	4,522	472
2004	5,451	884	4,567	473
2005	5,714	913	4,800	480
2006	5,893	933	4,959	479
2007	6,041	953	5,088	470
2008	6,305	968	5,337	470
2009	6,424	978	5,446	480
2010	6,508	998	5,510	486
2011	6,513	1,003	5,510	486
2012	7,114	1,117	5,997	529

Table A-160: Synthetic Fiber Production in 1999

Fiber	Production (Tg)	Carbon Content
Polyester	1.8	63%
Nylon	1.2	64%
Olefin	1.4	86%
Acrylic	0.1	68%
Total	**4.5**	**70%**

N_2O and CH_4 from Incineration of Waste

Estimates of N_2O emissions from the incineration of waste in the United States are based on the methodology outlined in the EPA's Compilation of Air Pollutant Emission Factors (EPA 1995) and presented in the *Municipal Solid Waste Generation, Recycling, and Disposal in the United States: Facts and Figures* reports (EPA 1999 through 2003, 2005 through 2014) and unpublished backup data (Schneider 2007). According to this methodology, emissions of N_2O from waste incineration are the product of the mass of waste incinerated, an emission factor of N_2O emitted per unit mass of waste incinerated, and an N_2O emissions control removal efficiency. The mass of waste incinerated was derived from the information published in *BioCycle* (van Haaren et al. 2010). For waste incineration in the United States, an emission factor of 50 g N_2O/metric ton MSW based on the 2006 IPCC Guidelines and an estimated emissions control removal efficiency of zero percent were used (IPCC 2006). It was assumed that all MSW incinerators in the United States use continuously-fed stoker technology (Bahor 2009, ERC 2009).

Estimates of CH_4 emissions from the incineration of waste in the United States are based on the methodology outlined in IPCC's *2006 Guidelines for National Greenhouse Gas Inventories* (IPCC 2006). According to this methodology, emissions of CH_4 from waste incineration are the product of the mass of waste incinerated and an emission factor of CH_4 emitted per unit mass of waste incinerated. Similar to the N_2O emissions methodology, the mass of waste incinerated was derived from the information published in *Biocycle* (van Haaren et al. 2010). For waste incineration in the United States, an emission factor of 0.20 kg CH_4/Gg MSW was used based on the 2006 IPCC Guidelines and assuming that all MSW incinerators in the United States use continuously-fed stoker technology (Bahor 2009, ERC 2009). No information was available on the mass of waste incinerated from *Biocycle* in 2009 through 2012, so these values were assumed to remain constant at the 2008 level.

Despite the differences in methodology and data sources, the two series of references (EPA's and BioCycle's) provide estimates of total solid waste incinerated that are relatively consistent (see Table A-160).

Table A-161: U.S. Municipal Solid Waste Incinerated, as Reported by EPA and BioCycle (Metric Tons)

Year	EPA	BioCycle
1990	28,939,680	30,632,057
1995	32,241,888	29,639,040
1996	32,740,848	29,707,171
1997	33,294,240	27,798,368
1998	31,216,752	25,489,893
1999	30,881,088	24,296,249
2000	30,599,856	25,974,978
2001	30,481,920	25,942,036[a]
2002	30,255,120	25,802,917
2003	30,028,320	25,930,542[b]
2004	28,585,872	26,037,823
2005	28,685,664	25,973,520[c]
2006	28,985,040	25,853,401
2007	29,003,184	24,788,539[d]
2008	28,622,160	23,674,017
2009	26,317,872	NA
2010	26,544,672	NA
2011	26,544,672	NA
2012	26,544,672	NA

NA (Not Available)

[a] Interpolated between 2000 and 2002 values.

[b] Interpolated between 2002 and 2004 values.

[c] Interpolated between 2004 and 2006 values.

[d] Interpolated between 2006 and 2008 values

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

Bunker fuel emissions estimates for the Department of Defense (DoD) are developed using data generated by the Defense Energy Support Center (DESC) for aviation and naval fuels. The DESC of the Defense Logistics Agency (DLA) prepared a special report based on data in the Fuels Automated System (FAS), a database that recently replaced the Defense Fuels Automated Management System (DFAMS). Data for intermediate fuel oil, however, currently remains in the original DFAMS database. DFAMS/FAS contains data for 1995 through 2012, 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 DoD between 1992 and 1995.

Step 1: Omit Extra-Territorial Fuel Deliveries

Beginning with the complete FAS 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 international fuel transactions/deliveries (i.e., sales abroad).

Step 2: Allocate JP-8 between Aviation and Land-based Vehicles

As a result of DoD[63] and NATO[64] 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 use should be reallocated from the aviation subtotal to a new land-based jet fuel category for 1997 and subsequent years. The amount of JP8 reallocated was determined to be between 1.78 and 2.7 times the amount of diesel fuel used, depending on the Service. 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 A-162 displays DoD's consumption of fuels that remain at the completion of Step 1, summarized by fuel type. Table A-162 reflects the adjustments for jet fuel 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, were considered 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).

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 was considered a potential international bunker fuel. Fuel consumed in international aviation or marine transport was included in the

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

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

bunker fuel estimate of the country where the ship or aircraft was fueled. Fuel consumed entirely within a country's borders was not considered a 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 consumed 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 purchased fuel from DLA Energy 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 Flying Hour Projection System Budget for fiscal year 1998, 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 were underway were 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 A-163 and Table A-164 display DoD bunker fuel use totals for the Navy and Air Force.

Step 6: Calculate Emissions from International Bunker Fuels

Bunker fuel totals were multiplied by appropriate emission factors to determine GHG emissions. CO_2 emissions from Aviation Bunkers and distillate Marine Bunkers are the total of military aviation and marine bunker fuels, respectively.

The rows labeled "U.S. Military" and "U.S. Military Naval Fuels" in the tables in the International Bunker Fuels section of the Energy Chapter were based on the totals provided in Table A-163 and Table A-164, below. CO_2 emissions from aviation bunkers and distillate marine bunkers presented in Table A-167, and are based on emissions from fuels tallied in Table A-163 and Table A-164

Table A-162: Transportation Fuels from Domestic Fuel Deliveries[a] (Million Gallons)

Vehicle Type/Fuel	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Aviation	**4,598.4**	**3,099.9**	**2,941.9**	**2,685.6**	**2,741.4**	**2,635.2**	**2,664.4**	**2,900.6**	**2,609.8**	**2,615.0**	**2,703.1**	**2,338.1**	**2,092.0**	**2,081.0**	**2,067.8**	**1,814.5**	**1,663.9**	**1,405.0**	**1,449.7**
Total Jet Fuels	**4,598.4**	**3,099.9**	**2,941.9**	**2,685.6**	**2,741.4**	**2,635.2**	**2,664.4**	**2,900.6**	**2,609.6**	**2,614.9**	**2,703.1**	**2,338.0**	**2,091.9**	**2,080.9**	**2,067.7**	**1,814.3**	**1,663.7**	**1,404.8**	**1,449.5**
JP8	285.7	2,182.8	2,253.1	2,072.0	2,122.5	2,066.5	2,122.7	2,326.2	2,091.4	2,094.3	2,126.2	1,838.8	1,709.3	1,618.5	1,616.2	1,358.2	1,100.1	882.8	865.2
JP5	1,025.4	691.2	615.8	552.8	515.6	505.5	472.1	503.2	442.2	409.1	433.7	421.6	325.5	376.1	362.2	361.2	399.3	372.3	362.5
Other Jet Fuels	3,287.3	225.9	72.9	60.9	103.3	63.3	69.6	71.2	76.1	111.4	143.2	77.6	57.0	86.3	89.2	94.8	164.3	149.7	221.8
Aviation Gasoline	+	+	+	+	+	+	+	+	0.1	0.1	+	0.1	0.1	0.2	0.1	0.2	0.2	0.2	0.3
Marine	**686.8**	**438.9**	**493.3**	**639.8**	**674.2**	**598.9**	**454.4**	**418.4**	**455.8**	**609.1**	**704.5**	**604.9**	**531.6**	**572.8**	**563.4**	**485.8**	**578.8**	**489.9**	**490.4**
Middle Distillate (MGO)	+	+	38.5	47.5	51.1	49.2	48.3	33.0	41.2	88.1	71.2	54.0	45.8	45.7	55.2	56.8	48.4	37.3	52.9
Naval Distillate (F76)	686.8	438.9	449.0	583.4	608.4	542.9	398.0	369.1	395.1	460.9	583.5	525.9	453.6	516.0	483.4	399.0	513.7	440.0	428.4
Intermediate Fuel Oil (IFO)[b]	+	+	5.9	9.0	14.7	6.7	8.1	16.3	19.5	60.2	49.9	25.0	32.2	11.1	24.9	30.0	16.7	12.5	9.1
Other[c]	**717.1**	**310.9**	**276.9**	**263.3**	**256.8**	**256.0**	**248.2**	**109.8**	**211.1**	**221.2**	**170.9**	**205.6**	**107.3**	**169.0**	**173.6**	**206.8**	**224.0**	**208.6**	**193.8**
Diesel	93.0	119.9	126.1	132.6	139.5	146.8	126.6	26.6	57.7	60.8	46.4	56.8	30.6	47.3	49.1	58.3	64.1	60.9	57.9
Gasoline	624.1	191.1	150.8	119.0	93.9	74.1	74.8	24.7	27.5	26.5	19.4	24.3	11.7	19.2	19.7	25.2	25.5	22.0	19.6
Jet Fuel[d]	+	+	+	11.7	23.4	35.0	46.7	58.4	125.9	133.9	105.1	124.4	65.0	102.6	104.8	123.3	134.4	125.6	116.2
Total (Including Bunkers)	**6,002.4**	**3,849.8**	**3,712.1**	**3,588.8**	**3,672.4**	**3,490.1**	**3,367.0**	**3,428.8**	**3,276.7**	**3,445.3**	**3,578.5**	**3,148.6**	**2,730.9**	**2,822.8**	**2,804.9**	**2,507.1**	**2,466.7**	**2,103.5**	**2,133.9**

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. The 1997 through 1999 gasoline and diesel fuel data were initially extrapolated from the 1996 inventory data. Growth factors used for other diesel and gasoline were 5.2 and -21.1 percent, respectively. However, prior diesel fuel estimates from 1997 through 2000 were reduced according to the estimated consumption of jet fuel that is assumed to have replaced the diesel fuel consumption in land-based vehicles. Data sets for other diesel and gasoline consumed by the military in 2000 were 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/DLA.

[d] The fraction of jet fuel consumed in land-based vehicles was estimated using Service data, DESC/DLA Energy data, and expert judgment.

\+ Does not exceed 0.05 million gallons.

Table A-163: Total U.S. Military Aviation Bunker Fuel (Million Gallons)

Fuel Type/Service	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
JP8	**56.7**	**300.4**	**308.8**	**292.0**	**306.4**	**301.4**	**307.6**	**341.2**	**309.5**	**305.1**	**309.8**	**285.6**	**262.5**	**249.1**	**229.4**	**211.4**	**182.5**	**143.4**	**141.2**
Navy	56.7	38.3	39.8	46.9	53.8	55.5	53.4	73.8	86.6	76.3	79.2	70.9	64.7	62.7	59.2	55.4	60.8	47.1	50.4
Air Force	+	262.2	269.0	245.1	252.6	245.9	254.2	267.4	222.9	228.7	230.6	214.7	197.8	186.5	170.3	156.0	121.7	96.2	90.8
JP5	**370.5**	**249.8**	**219.4**	**194.2**	**184.4**	**175.4**	**160.3**	**169.7**	**158.3**	**146.1**	**157.9**	**160.6**	**125.0**	**144.5**	**139.2**	**137.0**	**152.5**	**144.9**	**141.2**
Navy	365.3	246.3	216.1	191.2	181.4	170.6	155.6	163.7	153.0	141.3	153.8	156.9	122.8	141.8	136.5	133.5	149.7	143.0	139.5
Air Force	5.3	3.5	3.3	3.0	3.0	4.8	4.7	6.1	5.3	4.9	4.1	3.7	2.3	2.7	2.6	3.5	2.8	1.8	1.7
JP4	**420.8**	**21.5**	**1.1**	**0.1**	**+**	**+**	**+**	**+**	**+**	**+**	**+**	**+**	**+**	**+**	**+**	**+**	**0.1**	**+**	**+**
Navy	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Air Force	420.8	21.5	1.1	0.1	+	+	+	+	+	+	+	+	+	+	+	+	0.1	+	+
JAA	**13.7**	**9.2**	**10.3**	**9.4**	**10.8**	**10.8**	**12.5**	**12.6**	**13.7**	**21.7**	**30.0**	**15.5**	**11.7**	**15.6**	**16.8**	**18.1**	**31.4**	**31.1**	**38.6**
Navy	8.5	5.7	6.6	5.9	6.6	6.3	7.9	8.0	9.8	15.5	21.5	11.6	9.1	11.7	12.5	12.3	13.7	14.6	14.8
Air Force	5.3	3.5	3.7	3.5	4.2	4.5	4.5	4.6	3.8	6.2	8.6	3.9	2.6	3.9	4.3	5.9	17.7	16.5	23.8
JA1	**+**	**+**	**+**	**+**	**+**	**+**	**+**	**0.1**	**0.6**	**0.2**	**0.5**	**0.5**	**0.4**	**1.1**	**1.0**	**0.6**	**0.3**	**-+**	**-+**
Navy	+	+	+	+	+	+	+	+	+	+	+	+	+	0.1	0.1	0.1	0.1	-+	-+
Air Force	+	+	+	+	+	+	+	0.1	0.6	0.2	0.5	0.5	0.4	1.0	0.8	0.5	0.1	-+	-+
JAB	**+**	**+**	**+**	**+**	**+**	**+**	**+**	**+**	**+**	**+**	**+**	**+**	**+**	**+**	**+**	**+**	**+**	**+**	**+**
Navy	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Air Force	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Navy Subtotal	**430.5**	**290.2**	**262.5**	**244.0**	**241.8**	**232.4**	**216.9**	**245.5**	**249.4**	**233.1**	**254.4**	**239.4**	**196.6**	**216.3**	**208.3**	**201.3**	**224.4**	**204.3**	**204.5**
Air Force Subtotal	**431.3**	**290.7**	**277.0**	**251.7**	**259.9**	**255.2**	**263.5**	**278.1**	**232.7**	**239.9**	**243.7**	**222.9**	**203.1**	**194.0**	**178.1**	**165.9**	**142.4**	**114.5**	**116.3**
Total	**861.8**	**580.9**	**539.5**	**495.6**	**501.7**	**487.5**	**480.4**	**523.6**	**482.1**	**473.0**	**498.1**	**462.3**	**399.7**	**410.3**	**386.3**	**367.2**	**366.7**	**318.8**	**320.8**

+ Does not exceed 0.05 million gallons.

Note: Totals may not sum due to independent rounding.

Table A-164: Total U.S. DoD Maritime Bunker Fuel (Million Gallons)

Marine Distillates	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Navy—MGO	+	+	30.3	35.6	31.9	39.7	23.8	22.5	27.1	63.7	56.2	38.0	33.0	31.6	40.9	39.9	32.9	25.5	36.5
Navy—F76	522.4	333.8	331.9	441.7	474.2	466.0	298.6	282.6	305.6	347.8	434.4	413.1	355.9	404.1	376.9	311.4	402.2	346.6	337.9
Navy—IFO	+	+	4.6	7.1	11.6	5.3	6.4	12.9	15.4	47.5	39.4	19.7	25.4	8.8	19.0	23.1	12.9	9.5	6.1
Total	**522.4**	**333.8**	**366.8**	**484.3**	**517.7**	**511.0**	**328.8**	**318.0**	**348.2**	**459.0**	**530.0**	**470.7**	**414.3**	**444.4**	**436.7**	**374.4**	**448.0**	**381.5**	**380.6**

+ Does not exceed 0.05 million gallons.

Note: Totals may not sum due to independent rounding.

Table A-165: Aviation and Marine Carbon Contents (Tg Carbon/QBtu) and Fraction Oxidized

Mode (Fuel)	Carbon Content Coefficient	Fraction Oxidized
Aviation (Jet Fuel)	Variable	1.00
Marine (Distillate)	20.17	1.00
Marine (Residual)	20.48	1.00

Source: EPA (2010) and IPCC (2006)

Table A-166: Annual Variable Carbon Content Coefficient for Jet Fuel (Tg Carbon/QBtu)

Fuel	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Jet Fuel	19.40	19.34	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70

Source: EPA (2010)

Table A-167: Total U.S. DoD CO_2 Emissions from Bunker Fuels (Tg CO_2 Eq.)

Mode	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Aviation	8.1	5.5	5.2	4.8	4.9	4.7	4.7	5.1	4.7	4.6	4.8	4.5	3.9	4.0	3.8	3.6	3.6	3.1	3.1
Marine	5.4	3.4	3.8	5.0	5.3	5.2	3.4	3.3	3.6	4.7	5.4	4.8	4.2	4.6	4.5	3.8	4.6	3.9	3.9
Total	**13.4**	**9.0**	**9.0**	**9.8**	**10.2**	**10.0**	**8.0**	**8.3**	**8.3**	**9.3**	**10.3**	**9.3**	**8.1**	**8.5**	**8.2**	**7.4**	**8.2**	**7.0**	**7.0**

Note: Totals may not sum due to independent rounding.

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

Emissions of HFCs and PFCs from the substitution of ozone depleting substances (ODS) are developed using a country-specific modeling approach. The Vintaging Model was developed as a tool for estimating the annual chemical emissions from industrial sectors that have historically used ODS in their products. Under the terms of the Montreal Protocol and the United States' Clean Air Act Amendments of 1990, the domestic U.S. consumption of ODS—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 ODS alternatives 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 five ODS substitute end-use sectors: air-conditioning and refrigeration, foams, aerosols, solvents, and fire-extinguishing. Within these sectors, there are 60 independently modeled end-uses. The model requires information on the market growth for each of the end-uses, a history of the market transition from ODS to alternatives, and the characteristics of each end-use such as market size or charge sizes and loss rates. As ODS are phased out, a percentage of the market share originally filled by the ODS 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 and ODS and ODS substitute in each of the end-uses. The simulation is considered to be a "business-as-usual" baseline case, and does not incorporate measures to reduce or eliminate the emissions of these gases other than those regulated by U.S. law or otherwise common in the industry. 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 Stratospheric Protection 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 conference proceedings from the International Conferences on Ozone Protection Technologies and Earth Technologies Forums. EPA also coordinates extensively with numerous trade associations and individual companies. For example, the Alliance for Responsible Atmospheric Policy; the Air-Conditioning, Heating 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 emission equations used in the Vintaging Model for each broad end-use category. These equations are applied separately for each chemical used within each of the 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 alternatives can be inferred by determining the transition path of each regulated ODS used in the early 1990s. Using data gleaned from a variety of sources, assessments are made regarding which alternatives have been used, and what fraction of the ODS market in each end-use has been 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.

Methodology

The Vintaging Model estimates the use and emissions of ODS alternatives by taking the following steps:

1. *Gather historical data*. The Vintaging Model is populated with information on each end-use, taken from published sources and industry experts.

2. *Simulate the implementation of new, non-ODS technologies*. The Vintaging Model uses detailed characterizations of the existing uses of the ODS, as well as data on how the substitutes are replacing the ODS, to simulate the implementation of new technologies that enter the market in compliance with ODS phase-out policies. As part of this simulation, the ODS substitutes are introduced in each of the end-uses over time as seen historically and as needed to comply with the ODS phase-out.

3. *Estimate emissions of the ODS substitutes*. The chemical use is estimated from the amount of substitutes that are required each year for the manufacture, installation, use, or servicing of products. The emissions are estimated from the emission profile for each vintage of equipment or product in each end-use. By aggregating the emissions from each vintage, a time profile of emissions from each end-use is developed.

Each set of end-uses is discussed in more detail in the following sections.

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. For any given year, these lifetime emissions (for existing equipment) and disposal emissions (from discarded equipment) 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

Emissions from any piece of equipment include both the amount of chemical leaked during equipment operation and the amount emitted during service. 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 by weight.

i = Counter, runs from 1 to lifetime (k).

j = Year of emission.

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 year $j-k+1$, 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)).

j = Year of emission.

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 leakage and servicing (including recharging) of equipment.

Ed = Emissions from Equipment Disposed. Emissions in year j from the disposal of equipment.

j = Year of emission.

Assumptions

The assumptions used by the Vintaging Model to trace the transition of each type of equipment away from ODS are presented in Table A- 168, below. As new technologies replace older ones, it is generally assumed that there are improvements in their leak, service, and disposal emission rates. Additionally, the market for each equipment type is assumed to grow independently, according to annual growth rates.

Table A- 168: Refrigeration and Air-Conditioning Market Transition Assumptions

Initial Market Segment	Primary Substitute				Secondary Substitute				Tertiary Substitute				Growth Rate
	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	
Centrifugal Chillers													
CFC-11	HCFC-123	1993	1993	45%	Unknown								0.5%
	HCFC-22	1991	1993	16%	HFC-134a	2000	2010	100%	None				
	HFC-134a	1992	1993	39%	None								
CFC-12	HFC-134a	1992	1994	53%	None								0.5%
	HCFC-22	1991	1994	16%	HFC-134a	2000	2010	100%	None				
	HCFC-123	1993	1994	31%	Unknown								
R-500	HFC-134a	1992	1994	53%	None								0.5%
	HCFC-22	1991	1994	16%	HFC-134a	2000	2010	100%	None				
	HCFC-123	1993	1994	31%	Unknown								
CFC-114	HFC-236fa	1993	1996	100%	HFC-134a	1998	2009	100%	None				0.2%
Cold Storage													
CFC-12	HCFC-22	1990	1993	65%	R-404A	1996	2010	75%	None				2.5%
					R-507	1996	2010	25%	None				
	R-404A	1994	1996	26%	None								
	R-507	1994	1996	9%	None								
HCFC-22	HCFC-22	1992	1993	100%	R-404A	1996	2009	8%	None				2.5%
					R-507	1996	2009	3%	None				
					R-404A	2009	2010	68%	None				
					R-507	2009	2010	23%	None				
R-502	HCFC-22	1990	1993	40%	R-404A	1996	2010	38%	None				2.5%
					R-507	1996	2010	12%	None				
					Non-ODP/GWP	1996	2010	50%	None				
	R-404A	1993	1996	45%	None								
	R-507	1994	1996	15%	None								
Commercial Unitary Air Conditioners (Large)													
HCFC-22	HCFC-22	1992	1993	100%	R-410A	2001	2005	5%	None				0.8%
					R-407C	2006	2009	1%	None				
					R-410A	2006	2009	9%	None				
					R-407C	2009	2010	5%	None				
					R-410A	2009	2010	81%	None				
Commercial Unitary Air Conditioners (Small)													
HCFC-22	HCFC-22	1992	1993	100%	R-410A	1996	2000	3%	None				0.8%
					R-410A	2001	2005	18%	None				
					R-410A	2006	2009	8%	None				
					R-410A	2009	2010	71%	None				
Dehumidifiers													
HCFC-22	HFC-134a	1997	1997	89%	None								0.2%
	R-410A	2007	2010	11%	None								

Initial Market Segment	Primary Substitute				Secondary Substitute				Tertiary Substitute				Growth Rate
	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	
Ice Makers													
CFC-12	HFC-134a	1993	1995	100%	None								2.5%
Industrial Process Refrigeration													
CFC-11	HCFC-123	1992	1994	70%	Unknown								2.5%
	HFC-134a	1992	1994	15%	None								
	HCFC-22	1991	1994	15%	HFC-134a	1995	2010	100%	None				
CFC-12	HCFC-22	1991	1994	10%	HFC-134a	1995	2010	15%	None				2.5%
					R-404A	1995	2010	50%	None				
					R-410A	1999	2010	20%	None				
					R-507	1995	2010	15%	None				
	HCFC-123	1992	1994	35%	Unknown								
	HFC-134a	1992	1994	50%	None								
	R-401A	1995	1996	5%	HFC-134a	1997	2000	100%	None				
HCFC-22	HFC-134a	1995	2009	2%	None								2.5%
	R-404A	1995	2009	5%	None								
	R-410A	1999	2009	2%	None								
	R-507	1995	2009	2%	None								
	HFC-134a	2009	2010	14%	None								
	R-404A	2009	2010	45%	None								
	R-410A	2009	2010	18%	None								
	R-507	2009	2010	14%	None								
Mobile Air Conditioners (Passenger Cars)													
CFC-12	HFC-134a	1992	1994	100%	HFO-1234yf	2012	2015	1%	None				0.5%
					HFO-1234yf	2016	2021	99%	None				
Mobile Air Conditioners (Light Duty Trucks)													
CFC-12	HFC-134a	1993	1994	100%	HFO-1234yf	2012	2015	1%	None				2%
					HFO-1234yf	2016	2021	99%	None				
Mobile Air Conditioners (School and Tour Buses)													
CFC-12	HCFC-22	1994	1995	0.5%	HFC-134a	2006	2007	100%	None				2.6%
	HFC-134a	1994	1997	99.5%	None								
Mobile Air Conditioners (Transit Buses)													
HCFC-22	HFC-134a	1995	2009	100%	None								2.6%

Initial Market Segment	Primary Substitute				Secondary Substitute				Tertiary Substitute				Growth Rate
	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	
Mobile Air Conditioners (Trains)													
HCFC-22	HFC-134a	2002	2009	50%	None								2.6%
	R-407C	2002	2009	50%	None								
Packaged Terminal Air Conditioners and Heat Pumps													
HCFC-22	R-410A	2006	2009	10%	None								0.8%
	R-410A	2009	2010	90%	None								
Positive Displacement Chillers													
HCFC-22	HFC-134a	2000	2009	9%	R-407C	2010	2020	60%	None				0.5%
					R-410A	2010	2020	40%	None				
	R-407C	2000	2009	1%	None								
	HFC-134a	2009	2010	81%	R-407C	2010	2020	60%	None				
									R-410A	2010	2020	40%	
					R-407C	2009	2010	9%	None				
CFC-12	HCFC-22	1993	1993	100%	HFC-134a	2000	2009	9%	R-407C	2010	2020	60%	0.2%
									R-410A	2010	2020	40%	
					R-407C	2000	2009	1%	None				
					HFC-134a	2009	2010	81%	R-407C	2010	2020	60%	
									R-410A	2010	2020	40%	
					R-407C	2009	2010	9%	None				
Refrigerated Appliances													
CFC-12	HFC-134a	1994	1995	100%	None								0.5%
Residential Unitary Air Conditioners													
HCFC-22	HCFC-22	2006	2006	70%	R-410A	2007	2010	29%	None				0.8%
					R-410A	2010	2010	71%	None				
	R-410A	2000	2005	5%	R-410A	2006	2006	100%	None				
	R-410A	2000	2006	5%	None								
	R-410A	2006	2006	20%	None								
Retail Food (Large; Technology Transition)													
DX[65]	DX	2000	2010	85%	DX	2010	2010	66%	None				0.8%

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[65] DX refers to direct expansion systems where the compressors are mounted together in a rack and share suction and discharge refrigeration lines that run throughout the store, feeding refrigerant to the display cases in the sales area.

[2] DR refers to distributed refrigeration systems that consist of multiple smaller units that are located close to the display cases that they serve such as on the roof above the cases, behind a nearby wall, or on top of or next to the case in the sales area.

[3] SLS refers to secondary loop systems wherein a secondary fluid such as glycol or carbon dioxide is cooled by the primary refrigerant in the machine room and then pumped throughout the store to remove heat from the display equipment.

[4] The CFC-12 large retail food market for new systems transitioned to R-502 from 1998 to 1990, and subsequently transitioned to HCFC-22 from 1990 to 1993. These transitions are not shown in the table in order to provide the HFC transitions in greater detail.

[5] HCFC-22 for new equipment after 2010 is assumed to be reclaimed material.

Initial Market Segment	Primary Substitute				Secondary Substitute				Tertiary Substitute				Growth Rate
	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	
					DR[2]	2010	2010	30%	None				
					SLS[3]	2010	2010	4%	None				
	DR	2000	2010	13.5%	None								
	SLS	2000	2010	1.5%	None								
Retail Food (Large; Refrigerant Transition)													
CFC-12 and R-502[4]	R-404A	1995	2000	17.5%	R-404A	2000	2009	17.9%	None				0.8%
					R-507	2000	2009	1.7%	None				
					R-407A	2000	2009	0.4%	None				
	R-507	1995	2000	7.5%	R-404A	2000	2009	17.9%	None				
					R-507	2000	2009	1.7%	None				
					R-407A	2000	2009	0.4%	None				
	HCFC-22	1995	2000	75%	R-404A	2001	2010	17.9%	None				
					R-507	2001	2010	1.7%	None				
					R-407A	2001	2010	0.4%	None				
					R-404A	2009	2010	68%	R-404A	2010	2010	35.8%	
									R-507	2010	2010	3.6%	
									R-407A	2010	2010	0.7%	
					R-507	2009	2010	8.0%	R-404A	2010	2010	35.8%	
									R-507	2010	2010	3.6%	
									R-407A	2010	2010	0.7%	
					R-407A	2009	2010	4.0%	R-404A	2010	2010	35.8%	
									R-507	2010	2010	3.6%	
									R-407A	2010	2010	0.7%	
Retail Food (Large Condensing Units)													
HCFC-22	R-402A	1995	2005	5%	R-404A	2006	2006	100%	None				0.9%
	R-404A	1995	2005	25%	None								
	R-507	1995	2005	10%	None								
	R-404A	2008	2010	45%	None								
	R-507	2008	2010	15%	None								
Retail Food (Small Condensing Units)													
HCFC-22	R-401A	1995	2005	6%	HFC-134a	2006	2006	100%	None				0.9%

Initial Market Segment	Primary Substitute				Secondary Substitute				Tertiary Substitute				Growth Rate
	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	
	R-402A	1995	2005	4%	HFC-134a	2006	2006	100%	None				
	HFC-134a	1993	2005	30%									
	R-404A	1995	2005	30%									
	R-404A	2008	2010	30%									
Retail Food (Small)													
CFC-12	HCFC-22	1990	1993	90%	HFC-134a	1993	1995	90%	CO_2	2010	2010	5%	0.8%
					R-404A	2000	2009	7.5%	None				
					R-507	2000	2009	2.5%	None				
	R-404A	1993	1996	7.5%	None								
	R-507	1993	1996	2.5%	None								
Transport Refrigeration													
CFC-12	HFC-134a	1993	1995	98%	None								2.5%
	HCFC-22	1993	1995	2%	HFC-134a	1995	1999	100%	None				
R-502	HFC-134a	1993	1995	55%	None								2.5%
	R-404A	1993	1995	45%	None								
Water-Source and Ground-Source Heat Pumps													
HCFC-22	R-407C	2000	2006	5%					None				0.8%
	R-410A	2000	2006	5%					None				
	HFC-134a	2000	2009	2%					None				
	R-407C	2006	2009	2.5%					None				
	R-410A	2006	2009	4.5%					None				
	HFC-134a	2009	2010	18%					None				
	R-407C	2009	2010	22.5%					None				
	R-410A	2009	2010	40.5%					None				
Window Units													
HCFC-22	R-410A	2008	2009	10%	None								5.0%
	R-410A	2009	2010	90%	None								

Table A- 169 presents the average equipment lifetimes and annual HFC emission rates (for servicing and leaks) for each end-use assumed by the Vintaging Model.

Table A- 169. Refrigeration and Air-conditioning Lifetime Assumptions

End-Use	Lifetime (Years)	HFC Emission Rates (%)
Centrifugal Chillers	20 – 27	2.0 – 10.9
Cold Storage	20 – 25	15.0
Commercial Unitary A/C	15	7.9 – 8.6
Dehumidifiers	11	0.5
Ice Makers	20	3.0
Industrial Process Refrigeration	25	3.6 – 12.3
Mobile Air Conditioners	5 –16	2.3 – 18.0
Positive Displacement Chillers	20	0.5 – 1.5
PTAC/PTHP	12	3.9
Retail Food	18 – 20	1.0 – 25
Refrigerated Appliances	14	0.6
Residential Unitary A/C	15	11.8
Transport Refrigeration	12	20.6 – 27.9
Water & Ground Source Heat Pumps	20	3.9
Window Units	12	0.6

Aerosols

ODSs, HFCs and many other chemicals are used as propellant aerosols. Pressurized within a container, a nozzle releases the chemical, which allows the product within the can to also be released. Two types of aerosol products are modeled: metered dose inhalers (MDI) and consumer aerosols. In the United States, the use of CFCs in consumer aerosols was banned in 1978, and many products transitioned to hydrocarbons or “not-in-kind” technologies, such as solid deodorants and finger-pump hair sprays. However, MDIs can continue to use CFCs as propellants because their use has been deemed essential. Essential use exemptions granted to the United States under the Montreal Protocol for CFC use in MDIs are limited to the treatment of asthma and chronic obstructive pulmonary disease.

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.

j = Year of emission.

Transition Assumptions

Transition assumptions and growth rates for those items that use ODSs or HFCs as propellants, including vital medical devices and specialty consumer products, are presented in Table A- 170.

Table A- 170. Aerosol Product Transition Assumptions

Initial Market Segment	Primary Substitute				Secondary Substitute				Growth Rate
	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	
MDIs									
CFC Mix*	HFC-134a	1997	1997	6%	None				0.8%
	Non-ODP/GWP	1998	2007	7%	None				
	CFC Mix*	2000	2000	87%	HFC-134a	2002	2002	34%	
					HFC-134a	2003	2009	47%	
					HFC-227ea	2006	2009	5%	
					HFC-134a	2010	2011	6%	
					HFC-227ea	2010	2011	1%	
					HFC-134a	2011	2012	3%	
					HFC-227ea	2011	2012	0.3%	
					HFC-134a	2014	2014	3%	
					HFC-227ea	2014	2014	0.3%	
Consumer Aerosols (Non-MDIs)									
NA**	HFC-152a	1990	1991	50%	None				2.0%
	HFC-134a	1995	1995	50%	HFC-152a	1997	1998	44%	
					HFC-152a	2001	2005	36%	

*CFC Mix consists of CFC-11, CFC-12 and CFC-114 and represents the weighted average of several CFCs consumed for essential use in MDIs from 1993 to 2008.

**Consumer Aerosols transitioned away from ODS prior to 1985, the year in which the Vintaging Model begins. The portion of the market that is now using HFC propellants is modeled.

Solvents

ODSs, HFCs, PFCs and other chemicals are used as solvents to clean items. For example, electronics may need to be cleaned after production to remove any manufacturing process oils or residues left. Solvents are applied by moving the item to be cleaned within a bath or stream of the solvent. 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, assumed to be 90 percent.

Qc = Quantity of Chemical. Total quantity of a specific chemical sold for use in solvent applications in the year j, by weight.

j = Year of emission.

Transition Assumptions

The transition assumptions and growth rates used within the Vintaging Model for electronics cleaning, metals cleaning, precision cleaning, and adhesives, coatings and inks, are presented in Table A- 171.

Table A- 171. Solvent Market Transition Assumptions

Initial Market Segment	Primary Substitute				Secondary Substitute				Growth Rate
	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	
				Adhesives					
CH_3CCl_3	Non-ODP/GWP	1994	1995	100%	None				2.0%
				Electronics					
CFC-113	Semi-Aqueous	1994	1995	52%	None				2.0%
	HCFC-225ca/cb	1994	1995	0.2%	Unknown				
	HFC-43-10mee	1995	1996	0.7%	None				
	HFE-7100	1994	1995	0.7%	None				
	nPB	1992	1996	5%	None				
	Methyl Siloxanes	1992	1996	0.8%	None				
	No-Clean	1992	1996	40%	None				
CH_3CCl_3	Non-ODP/GWP	1996	1997	99.8%	None				2.0%
	PFC/PFPE	1996	1997	0.2%	Non-ODP/GWP	2000	2003	90%	
					Non-ODP/GWP	2005	2009	10%	
				Metals					
CH_3CCl_3	Non-ODP/GWP	1992	1996	100%	None				2.0%
CFC-113	Non-ODP/GWP	1992	1996	100%	None				2.0%
CCl_4	Non-ODP/GWP	1992	1996	100%	None				2.0%
				Precision					
CH_3CCl_3	Non-ODP/GWP	1995	1996	99.3%	None				2.0%
	HFC-43-10mee	1995	1996	0.6%	None				
	PFC/PFPE	1995	1996	0.1%	Non-ODP/GWP	2000	2003	90%	
					Non-ODP/GWP	2005	2009	10%	
CFC-113	Non-ODP/GWP	1995	1996	96%	None				2.0%
	HCFC-225ca/cb	1995	1996	1%	Unknown				
	HFE-7100	1995	1996	3%	None				

Non-ODP/GWP includes chemicals with 0 ODP and low GWP, such as hydrocarbons and ammonia, as well as not-in-kind alternatives such as “no clean” technologies.

Fire Extinguishing

ODSs, HFCs, PFCs and other chemicals are used as fire-extinguishing agents, in both hand-held “streaming” applications as well as in built-up “flooding” equipment similar to water sprinkler systems. Although these systems are generally built to be leak-tight, some leaks do occur and of course emissions occur when the agent is released. 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, as shown in the equation below. In streaming systems, non-halon emissions are assumed to be 3.5 percent of all chemical in use in each year, while in flooding systems 2.5 percent of the installed base of chemical is assumed to leak annually. Halon systems are assumed to leak at higher rates. The equation is applied for a single year, accounting for all fire protection equipment in operation in that year. Each fire protection agent is modeled separately. In the Vintaging Model, streaming applications have a 12-year lifetime and flooding applications have a 20-year lifetime.

$$E_j = \mathrm{r} \times \sum Qc_{j-i+1} \quad \textit{for } i=1\rightarrow k$$

Where:

E = Emissions. Total emissions of a specific chemical in year j for streaming fire extinguishing equipment, by weight.

r = Percent Released. The percentage of the total chemical in operation that is released to the atmosphere.

Qc = Quantity of Chemical. Total amount of a specific chemical used in new fire extinguishing equipment in a given year, j-i+1, by weight.

i = Counter, runs from 1 to lifetime (k).

j = Year of emission.

k = Lifetime. The average lifetime of the equipment.

Transition Assumptions

Transition assumptions and growth rates for these two fire extinguishing types are presented in Table A- 172.

Table A- 172. Fire Extinguishing Market Transition Assumptions

Initial Market Segment	Primary Substitute				Secondary Substitute				Growth Rate
	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	
Flooding Agents									
Halon-1301	Halon-1301*	1994	1994	4%	Unknown				2.2%
	HFC-23	1994	1999	0.2%	None				
	HFC-227ea	1994	1999	18%	FK-5-1-12	2003	2010	10%	
					HFC-125	2001	2008	10%	
	Non-ODP/GWP	1994	1994	46%	FK-5-1-12	2003	2010	7%	
	Non-ODP/GWP	1995	2034	10%	None				
	Non-ODP/GWP	1998	2027	10%	None				
	C_4F_{10}	1994	1999	1%	FK-5-1-12	2003	2003	100%	
	HFC-125	1997	2006	11%	None				
Streaming Agents									
Halon-1211	Halon-1211*	1992	1992	5%	Unknown				3.0%
	HFC-236fa	1997	1999	3%	None				
	Halotron	1994	1997	4%	Non-ODP/GWP	2020	2020	25%	
					HFC-236fa	2020	2020	75%	
	Non-ODP/GWP	1993	1994	58%	None				
	Non-ODP/GWP	1995	2024	20%	None				
	Non-ODP/GWP	1999	2018	10%	None				

*Despite the 1994 consumption ban, a small percentage of new halon systems are assumed to continue to be built and filled with stockpiled or recovered supplies.

Foam Blowing

ODSs, HFCs, and other chemicals are used to produce foams, including such items as the foam insulation panels around refrigerators, insulation sprayed on buildings, etc. The chemical is used to create pockets of gas within a substrate, increasing the insulating properties of the item. 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 content upon manufacture, a portion at a constant rate over the lifetime of the foam, a portion at disposal, and a portion after disposal; these portions vary by end-use.

Step 1: Calculate manufacturing emissions (open-cell and closed-cell foams)

Manufacturing emissions occur in the year of foam manufacture, and are calculated as presented in the following equation.

$$Em_j = lm \times Qc_j$$

Where:

Em_j = Emissions from manufacturing. Total emissions of a specific chemical in year j due to manufacturing losses, by weight.

lm = Loss Rate. Percent of original blowing agent emitted during foam manufacture. For open-cell foams, lm is 100%.

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

j = Year of emission.

Step 2: Calculate lifetime emissions (closed-cell foams)

Lifetime emissions occur annually from closed-cell foams throughout the lifetime of the foam, as calculated as presented in the following equation.

$$Eu_j = lu \times \sum Qc_{j-i+1} \quad for\ i=1 \rightarrow k$$

Where:

Eu_j = Emissions from Lifetime Losses. Total emissions of a specific chemical in year j due to lifetime losses during use, by weight.

lu = Leak Rate. Percent of original blowing agent emitted each year during lifetime use.

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

i = Counter, runs from 1 to lifetime (k).

j = Year of emission.

k = Lifetime. The average lifetime of foam product.

Step 3: Calculate disposal emissions (closed-cell foams)

Disposal emissions occur in the year the foam is disposed, and are calculated as presented in the following equation.

$$Ed_j = ld \times Qc_{j-k}$$

Where:

Ed_j = Emissions from disposal. Total emissions of a specific chemical in year j at disposal, by weight.

ld = Loss Rate. Percent of original blowing agent emitted at disposal.

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

j = Year of emission.

k = Lifetime. The average lifetime of foam product.

Step 4: Calculate post-disposal emissions (closed-cell foams)

Post-Disposal emissions occur in the years after the foam is disposed; for example, emissions might occur while the disposed foam is in a landfill. Currently, the only foam type assumed to have post-disposal emissions is polyurethane foam used as domestic refrigerator and freezer insulation, which is expected to continue to emit for 26 years post-disposal, calculated as presented in the following equation.

$$Ep_j = lp \times \sum Qc_{j-m} \quad for\ m=k \rightarrow k + 26$$

Where:

Ep_j = Emissions from post disposal. Total post-disposal emissions of a specific chemical in year j, by weight.

lp = Leak Rate. Percent of original blowing agent emitted post disposal.

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

k = Lifetime. The average lifetime of foam product.

m = Counter. Runs from lifetime (k) to (k+26).

j = Year of emission.

Step 5: Calculate total emissions (open-cell and closed-cell foams)

To calculate total emissions from foams in any given year, emissions from all foam stages must be summed, as presented in the following equation.

$$E_j = Em_j + Eu_j + Ed_j + Ep_j$$

Where:

E_j = Total Emissions. Total emissions of a specific chemical in year j, by weight.

Em = Emissions from manufacturing. Total emissions of a specific chemical in year j due to manufacturing losses, by weight.

Eu_j = Emissions from Lifetime Losses. Total emissions of a specific chemical in year j due to lifetime losses during use, by weight.

Ed_j = Emissions from disposal. Total emissions of a specific chemical in year j at disposal, by weight.

Ep_j = Emissions from post disposal. Total post-disposal emissions of a specific chemical in year j, by weight.

Assumptions

The Vintaging Model contains 13 foam types, whose transition assumptions away from ODS and growth rates are presented in Table A- 173. The emission profiles of these 13 foam types are shown in Table A- 174.

Table A- 173. Foam Blowing Market Transition Assumptions

Initial Market Segment	Primary Substitute				Secondary Substitute				Tertiary Substitute				Growth Rate
	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	
Commercial Refrigeration Foam													
CFC-11	HCFC-141b	1989	1996	40%	HFC-245fa	2002	2003	80%	None				6.0%
					Non-ODP/GWP	2002	2003	20%	None				
	HCFC-142b	1989	1996	8%	Non-ODP/GWP	2009	2010	80%	None				
					HFC-245fa	2009	2010	20%	None				
	HCFC-22	1989	1996	52%	Non-ODP/GWP	2009	2010	80%	None				
					HFC-245fa	2009	2010	20%	None				
Flexible PU Foam: Integral Skin Foam													
CFC-11	HCFC-141b	1989	1990	100%	HFC-134a	1993	1996	25%	None				2.0%
					HFC-134a	1994	1996	25%	None				
					CO_2	1993	1996	25%	None				
					CO_2	1994	1996	25%	None				
Flexible PU Foam: Slabstock Foam, Moulded Foam													
CFC-11	Non-ODP/GWP	1992	1992	100%	None								2.0%
Phenolic Foam													
CFC-11	HCFC-141b	1989	1990	100%	Non-ODP/GWP	1992	1992	100%	None				2.0%
Polyolefin Foam													
CFC-114	HFC-152a	1989	1993	10%	Non-ODP/GWP	2005	2010	100%	None				2.0%
	HCFC-142b	1989	1993	90%	Non-ODP/GWP	1994	1996	100%	None				
PU and PIR Rigid: Boardstock													
CFC-11	HCFC-141b	1993	1996	100%	Non-ODP/GWP	2000	2003	95%	None				6.0%
					HC/HFC-245fa Blend	2000	2003	5%	None				
PU Rigid: Domestic Refrigerator and Freezer Insulation													
CFC-11	HCFC-141b	1993	1995	100%	HFC-134a	1996	2001	7%	Non-ODP/GWP	2002	2003	100%	0.8%
					HFC-245fa	2001	2003	50%	Non-ODP/GWP	2015	2029	100%	
					HFC-245fa	2006	2009	10%	Non-ODP/GWP	2015	2029	100%	
					Non-ODP/GWP	2002	2005	10%	None				
					Non-ODP/GWP	2006	2009	3%	None				
					Non-ODP/GWP	2009	2014	20%	None				

Initial Market Segment	Primary Substitute				Secondary Substitute				Tertiary Substitute				Growth Rate
	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	
PU Rigid: One Component Foam													
CFC-12	HCFC-142b/22 Blend	1989	1996	70%	Non-ODP/GWP	2009	2010	80%	None				4.0%
					HFC-134a	2009	2010	10%	None				
					HFC-152a	2009	2010	10%	None				
	HCFC-22	1989	1996	30%	Non-ODP/GWP	2009	2010	80%	None				
					HFC-134a	2009	2010	10%	None				
					HFC-152a	2009	2010	10%	None				
PU Rigid: Other: Slabstock Foam													
CFC-11	HCFC-141b	1989	1996	100%	CO_2	1999	2003	45%	None				2.0%
					Non-ODP/GWP	2001	2003	45%	None				
					HCFC-22	2003	2003	10%	Non-ODP/GWP	2009	2010	100%	
PU Rigid: Sandwich Panels: Continuous and Discontinuous													
CFC-11	HCFC-141b	1989	1996	82%	HCFC-22/Water Blend	2001	2003	20%	HFC-245fa/CO_2 Blend	2009	2010	50%	6.0%
									Non-ODP/GWP	2009	2010	50%	
					HFC-245fa/CO_2 Blend	2002	2004	20%	None				
					Non-ODP/GWP	2001	2004	40%	None				
					HFC-134a	2002	2004	20%	None				
	HCFC-22	1989	1996	18%	HFC-245fa/CO_2 Blend	2009	2010	40%	None				
					Non-ODP/GWP	2009	2010	20%	None				
					CO_2	2009	2010	20%	None				
					HFC-134a	2009	2010	20%	None				
PU Rigid: Spray Foam													
CFC-11	HCFC-141b	1989	1996	100%	HFC-245fa	2002	2003	30%	None				6.0%
					HFC-245fa/CO_2 Blend	2002	2003	60%	None				
					Non-ODP/GWP	2001	2003	10%	None				
XPS: Boardstock Foam													
CFC-12	HCFC-142b/22 Blend	1989	1994	10%	HFC-134a	2009	2010	70%	None				2.5%
					HFC-152a	2009	2010	10%	None				
					CO_2	2009	2010	10%	None				
					Non-ODP/GWP	2009	2010	10%	None				
	HCFC-142b	1989	1994	90%	HFC-134a	2009	2010	70%	None				
					HFC-152a	2009	2010	10%	None				
					CO_2	2009	2010	10%	None				
					Non-ODP/GWP	2009	2010	10%	None				
XPS: Sheet Foam													

Initial Market Segment	Primary Substitute				Secondary Substitute				Tertiary Substitute				Growth Rate
	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	
CFC-12	CO_2	1989	1994	1%	None								2.0%
	Non-ODP/GWP	1989	1994	99%	CO_2	1995	1999	9%	None				
					HFC-152a	1995	1999	10%	None				

Table A- 174. Emission profile for the foam end-uses

Foam End-Use	Loss at Manufacturing (%)	Annual Leakage Rate (%)	Leakage Lifetime (years)	Loss at Disposal (%)	Total* (%)
Flexible PU Foam: Slabstock Foam, Moulded Foam	100	0	1	0	100
Commercial Refrigeration	6	0.25	15	90.25	100
Rigid PU: Spray Foam	15	1.5	56	1	100
Rigid PU: Slabstock and Other	37.5	0.75	15	51.25	100
Phenolic Foam	23	0.875	32	49	100
Polyolefin Foam	95	2.5	2	0	100
Rigid PU: One Component Foam	100	0	1	0	100
XPS: Sheet Foam*	40	2	25	0	90
XPS: Boardstock Foam	25	0.75	50	37.5	100
Flexible PU Foam: Integral Skin Foam	95	2.5	2	0	100
Rigid PU: Domestic Refrigerator and Freezer Insulation*	4	0.25	14	40.0	47.5
PU and PIR Rigid: Boardstock	6	1	50	44	100
PU Sandwich Panels: Continuous and Discontinuous	5.5	0.5	50	69.5	100

PIR (Polyisicyanurate)
PU (Polyurethane)
XPS (Extruded Polystyrene)
*In general, total emissions from foam end-uses are assumed to be 100 percent, although work is underway to investigate that assumption. In the XPS Sheet/Insulation Board end-use, the source of emission rates and lifetimes did not yield 100 percent emission; it is unclear at this time whether that was intentional. In the Rigid PU Appliance Foam end-use, the source of emission rates and lifetimes did not yield 100 percent emission; the remainder is anticipated to be emitted at a rate of 2.0%/year post-disposal for the next 26 years.

Sterilization

Sterilants kill microorganisms on medical equipment and devices. The principal ODS used in this sector was a blend of 12% ethylene oxide (EtO) and 88% CFC-12, known as “12/88.” In that blend, ethylene oxide sterilizes the equipment and CFC-12 is a dilutent solvent to form a non-flammable blend. The sterilization sector is modeled as a single end-use. 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.

j = Year of emission.

Assumptions

The Vintaging Model contains 1 sterilization end-use, whose transition assumptions away from ODS and growth rates are presented in Table A- 175

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Table A- 175. Sterilization Market Transition Assumptions

Initial Market Segment	Primary Substitute				Secondary Substitute				Tertiary Substitute				Growth Rate
	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	
Commercial Refrigeration Foam													
12/88	EtO	1994	1995	95%	None								2.0%
	Non-ODP/GWP	1994	1995	1%	None								
	HCFC/EtO Blends	1993	1994	4%	Non-ODP/GWP	2010	2010	100%	None				

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 or sector basis. Values for use and emissions are calculated both in metric tons and in teragrams of CO_2 equivalents (Tg CO_2 Eq.). The conversion of metric tons of chemical to Tg CO_2 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.

Bank of ODS and ODS Substitutes

The bank of an ODS or an ODS substitute is "the cumulative difference between the chemical that has been consumed in an application or sub-application and that which has already been released" (IPCC 2006). For any given year, the bank is equal to the previous year's bank, less the chemical in equipment disposed of during the year, plus chemical in new equipment entering the market during that year, less the amount emitted but not replaced, plus the amount added to replace chemical emitted prior to the given year, as shown in the following equation:

$$Bc_j = Bc_{j-1} - Qd_j + Qp_j + E_e - Q_r$$

Where:

Bc_j = Bank of Chemical. Total bank of a specific chemical in year *j*, by weight.

Qd_j = Quantity of Chemical in Equipment Disposed. Total quantity of a specific chemical in equipment disposed of in year *j*, by weight.

Qp_j = Quantity of Chemical Penetrating the Market. Total quantity of a specific chemical that is entering the market in year *j*, by weight.

E_e = Emissions of Chemical Not Replaced. Total quantity of a specific chemical that is emitted during year j but is not replaced in that year. The Vintaging Model assumes all chemical emitted from refrigeration, air conditioning and fire extinguishing equipment is replaced in the year it is emitted, hence this term is zero for all sectors except foam blowing.

Q_r = Chemical Replacing Previous Year's Emissions. Total quantity of a specific chemical that is used to replace emissions that occurred prior to year j. The Vintaging Model assumes all chemical emitted from refrigeration, air conditioning and fire extinguishing equipment is replaced in the year it is emitted, hence this term is zero for all sectors.

j = Year of emission.

Table A- 176 provides the bank for ODS and ODS substitutes by chemical grouping in metric tons (MT) for 1990-2012.

Table A- 176. Banks of ODS and ODS Substitutes, 1990-2012 (MT)

	CFC	HCFC	HFC
1990	711,534	283,302	868
1995	807,182	497,582	53,696
2000	674,734	923,281	197,661
2001	645,931	992,260	227,436
2002	620,996	1,045,199	257,279
2003	596,076	1,081,664	293,046
2004	570,703	1,118,168	330,397
2005	547,210	1,159,858	368,806
2006	523,580	1,197,264	412,438
2007	502,928	1,226,849	456,497
2008	487,552	1,246,198	497,005
2009	480,177	1,241,550	544,053
2010	466,203	1,206,140	612,013
2011	452,162	1,161,244	679,111
2012	437,702	1,115,819	753,596

References

IPCC (2006) *2006 IPCC Guidelines for National Greenhouse Gas Inventories.* The National Greenhouse Gas Inventories Programme, The Intergovernmental Panel on Climate Change, H.S. Eggleston, L. Buendia, K. Miwa, T Ngara, and K. Tanabe (eds.). Hayama, Kanagawa, Japan.

3.10. Methodology for Estimating CH_4 Emissions from Enteric Fermentation

Methane emissions from enteric fermentation were estimated for seven livestock categories: cattle, horses, sheep, swine, goats, American bison, and the non-horse equines (mules and asses). Emissions from cattle represent the majority of U.S. emissions from enteric fermentation; consequently, a more detailed IPCC Tier 2 methodology was used to estimate emissions from cattle. The IPCC Tier 1 methodology was used to estimate emissions for the other types of livestock, including horses, goats, sheep, swine, American bison, and mules and asses.

Estimate Methane Emissions from Cattle

This section describes the process used to estimate CH_4 emissions from enteric fermentation from cattle using the Cattle Enteric Fermentation Model (CEFM). The CEFM was developed based on recommendations provided in IPCC/UNEP/OECD/IEA (1997), IPCC (2000) and IPCC (2006), and uses information on population, energy requirements, digestible energy, and CH_4 conversion rates to estimate CH_4 emissions.[66] The emission methodology consists of the following three steps: (1) characterize the cattle population to account for animal population categories with different emission profiles; (2) characterize cattle diets to generate information needed to estimate emission factors; and (3) estimate emissions using these data and the IPCC Tier 2 equations.

Step 1: Characterize U.S. Cattle Population

The state-level cattle population estimates are based on data obtained from the U.S. Department of Agriculture's (USDA) National Agricultural Statistics Service Quick Stats database (USDA 2012). A summary of the annual average populations upon which all livestock-related emissions are based is provided in Table A-177. Cattle populations used in the Enteric Fermentation source category were estimated using the cattle transition matrix in the CEFM, which uses January 1 USDA population estimates and weight data to simulate the population of U.S. cattle from birth to slaughter, and results in an estimate of the number of animals in a particular cattle grouping while taking into account the monthly rate of weight gain, the average weight of the animals, and the death and calving rates. The use of supplemental USDA data and the cattle transition matrix in the CEFM results in cattle population estimates for this sector differing slightly from the January 1 or July 1 USDA point estimates and the cattle population data obtained from the Food and Agriculture Organization of the United Nations (FAO).

Table A-177: Cattle Population Estimates from the CEFM Transition Matrix for 1990-2012 (1,000 head)

Livestock Type	1990	1995	2000	2005	2009	2010	2011	2012
Dairy								
Dairy Calves (4-6 months)	5,369	5,091	4,951	4,628	4,791	4,666	4,706	4,772
Dairy Cows	10,015	9,482	9,183	9,004	9,333	9,086	9,150	9,230
Dairy Replacements 7-11 months	1,214	1,216	1,196	1,257	1,327	1,347	1,362	1,350
Dairy Replacements 12-23 months	2,915	2,892	2,812	2,905	3,101	3,179	3,210	3,236
Beef								
Beef Calves (4-6 months)	16,909	18,177	17,431	16,918	16,051	16,043	15,795	15,186
Bulls	2,160	2,385	2,293	2,214	2,184	2,190	2,155	2,096
Beef Cows	32,455	35,190	33,575	32,674	31,712	31,371	30,850	30,158
Beef Replacements 7-11 months	1,269	1,493	1,313	1,363	1,290	1,239	1,230	1,250
Beef Replacements 12-23 months	2,967	3,637	3,097	3,171	3,098	3,055	2,890	2,957
Steer Stockers	10,321	11,716	8,724	8,185	8,515	8,223	7,628	7,209
Heifer Stockers	5,946	6,699	5,371	5,015	5,059	5,054	4,759	4,470
Feedlot Cattle	9,549	11,064	13,006	12,652	12,953	13,191	13,546	13,209

The population transition matrix in the CEFM simulates the U.S. cattle population over time and provides an estimate of the population age and weight structure by cattle type on a monthly basis.[67] Since cattle often do not remain in a single population type for an entire year (e.g., calves become stockers, stockers become feedlot animals), and emission profiles vary both between and within each cattle type, these monthly age groups are tracked in the enteric fermentation model to obtain more accurate emission estimates than would be available from annual point estimates of population (such as available from USDA statistics) and weight for each cattle type.

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[66] Additional information on the Cattle Enteric Fermentation Model can be found in ICF (2006).

[67] Mature animal populations are not assumed to have significant monthly fluctuations, and therefore the populations utilized are the January estimates downloaded from USDA (2013).

The transition matrix tracks both dairy and beef populations, and divides the populations into males and females, and subdivides the population further into specific cattle groupings for calves, replacements, stocker, feedlot, and mature animals. The matrix is based primarily on two types of data: population statistics and weight statistics (including target weights, slaughter weights, and weight gain). Using the weight data, the transition matrix simulates the growth of animals over time by month. The matrix also relies on supplementary data, such as feedlot placement statistics, slaughter statistics, death rates, and calving rates.

The basic method for tracking population of animals per category is based on the number of births (or graduates) into the monthly age group minus those animals that die or are slaughtered and those that graduate to the next category (such as stockers to feedlot placements).

Each stage in the cattle lifecycle was modeled to simulate the cattle population from birth to slaughter. This level of detail accounts for the variability in CH_4 emissions associated with each life stage. Given that a stage can last less than one year (e.g., calves are usually weaned between 4 and 6 months of age), each is modeled on a per-month basis. The type of cattle also influences CH_4 emissions (e.g., beef versus dairy). Consequently, there is an independent transition matrix for each of three separate lifecycle phases, 1) calves, 2) replacements and stockers, and 3) feedlot animals. In addition, the number of mature cows and bulls are tabulated for both dairy and beef stock. The transition matrix estimates total monthly populations for all cattle subtypes. These populations are then reallocated to the state level based on the percent of the cattle type reported in each state in the January 1 USDA data. Each lifecycle is discussed separately below, and the categories tracked are listed in Table A-178.

Table A-178: Cattle Population Categories Used for Estimating CH_4 Emissions

Dairy Cattle	Beef Cattle
Calves (4-6 months)	Calves (4-6 months)
Heifer Replacements	Heifer Replacements
Cows	Heifer and Steer Stockers
	Animals in Feedlots (Heifers & Steer)
	Cows
	Bulls[a]

[a] Bulls (beef and dairy) are accounted for in a single category.

The key variables tracked for each of these cattle population categories are as follows:

Calves. Although only the emissions for calves ages 4 to 6 months are calculated in the inventory, it is necessary to estimate populations from birth as estimates of populations for older cattle are reliant on understanding the available supply of calves from birth. The number of animals born on a monthly basis was used to initiate monthly cohorts and to determine population age structure. The number of calves born each month was obtained by multiplying annual births by the percentage of births per month. Annual birth information for each year was taken from USDA (2013). For dairy cows, the number of births is assumed to be distributed equally throughout the year (approximately 8.3 percent per month), beef births are distributed according to Table A-179, based on estimates from the National Animal Health Monitoring System (NAHMS) (USDA/APHIS/VS 1998, 1994, 1993). To determine whether calves were born to dairy or beef cows, the dairy cow calving rate (USDA/APHIS/VS 2002, USDA/APHIS/VS 1996) was multiplied by the total dairy cow population to determine the number of births attributable to dairy cows, with the remainder assumed to be attributable to beef cows. Total annual calf births are obtained from USDA, and distributed into monthly cohorts by cattle type (beef or dairy). Calf growth is modeled by month, based on estimated monthly weight gain for each cohort (approximately 61 pounds per month). The total calf population is modified through time to account for veal calf slaughter at 4 months and a calf death loss of 0.35 percent annually (distributed across age cohorts up to six months of age). An example of a transition matrix for calves is shown in Table A-180. Note that calves age one through six months available in January have been tracked through the model based on births and death loss from the previous year.

Table A-179: Estimated Beef Cow Births by Month

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
7%	15%	28%	22%	9%	3%	2%	2%	3%	4%	3%	3%

Table A-180: Example of Monthly Average Populations from Calf Transition Matrix (1,000 head)

Age (month)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
6	1,187	1,178	1,381	1,621	1,561	1,547	2,391	4,476	7,771	6,291	2,934	1,459
5	1,179	1,382	1,622	1,561	1,547	2,392	4,478	7,774	6,294	2,935	1,460	1,089
4	1,450	1,683	1,620	1,603	2,451	4,535	7,843	6,368	3,000	1,533	1,159	1,150
3	1,684	1,622	1,604	2,452	4,536	7,846	6,371	3,001	1,533	1,160	1,151	1,411
2	1,623	1,605	2,453	4,538	7,849	6,373	3,002	1,534	1,160	1,152	1,412	1,637
1	1,607	2,454	4,540	7,852	6,375	3,003	1,534	1,161	1,152	1,413	1,638	1,577
0	2,457	4,543	7,856	6,378	3,004	1,535	1,161	1,152	1,413	1,639	1,579	1,561

Note: The cohort starting at age 0 months on January 1 is tracked in order to illustrate how a single cohort moves through the transition matrix. Each month, the cohort reflects the decreases in population due to the estimated 0.35% annual death loss, and between months 4 and 5, a more significant loss is seen than in other months due to estimated veal slaughter.

Replacements and Stockers. At seven months of age, calves "graduate" and are separated into the applicable cattle types. First the number of replacements required for beef and dairy cattle are calculated based on estimated death losses and population changes between beginning and end of year population estimates. Based on the USDA estimates for "replacement beef heifers" and "replacement dairy heifers," the transition matrix for the replacements is back-calculated from the known animal totals from USDA, and the number of calves needed to fill that requirement for each month is subtracted from the known supply of female calves. All female calves remaining after those needed for beef and dairy replacements are removed become "stockers" that can be placed in feedlots (along with all male calves). During the stocker phase animals are subtracted out of the transition matrix for placement into feedlots based on feedlot placement statistics from USDA (2013).

The data and calculations that occur for the stocker category include matrices that estimate the population of backgrounding heifers and steer, as well as a matrix for total combined stockers. The matrices start with the beginning of year populations in January and model the progression of each cohort. The age structure of the January population is based on estimated births by month from the previous two years, although in order to balance the population properly, an adjustment is added that slightly reduces population percentages in the older populations. The populations are modified through addition of graduating calves (added in month 7, bottom row of Table A-181) and subtraction through death loss and animals placed in feedlots. Eventually, an entire cohort population of stockers may reach zero, indicating that the complete cohort has been transitioned into feedlots. An example of the transition matrix for stockers is shown in Table A-181.

Table A-181: Example of Monthly Average Populations from Stocker Transition Matrix (1,000 head)

Age (month)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
23	177	187	106	36	15	9	7	7	5	2	0	0
22	306	152	50	19	11	9	9	8	5	2	3	188
21	248	71	26	14	11	11	11	8	5	54	195	326
20	117	37	19	14	14	13	10	8	110	305	339	264
19	60	28	19	17	16	13	10	177	424	562	276	125
18	45	27	23	20	15	12	222	569	804	465	130	64
17	45	34	27	19	15	272	666	1,096	671	216	78	48
16	55	39	26	19	334	774	1,294	920	309	304	48	48
15	64	38	26	413	907	1,513	1,088	422	550	48	48	59
14	61	37	568	1,078	1,782	1,275	499	847	48	48	59	68
13	61	813	1,396	2,125	1,506	585	1,118	48	48	59	68	65
12	946	1,543	2,412	1,707	707	1,540	226	48	59	68	65	65
11	1,750	2,665	1,938	802	1,930	297	148	79	88	84	86	1,014
10	3,026	2,158	903	2,306	419	210	188	236	205	207	1,153	2,368
9	2,456	1,023	2,601	521	387	384	421	417	385	1,308	2,856	5,180
8	1,157	3,091	704	534	647	787	710	737	1,509	3,326	6,107	4,910
7	3,520	853	846	1,018	1,232	1,179	1,168	1,920	3,764	6,676	5,368	2,401

Note: The cohort starting at age 7 months on January 1 is tracked in order to illustrate how a single cohort moves through the transition matrix. Each month, the cohort reflects the decreases in population due to the estimated 0.35% annual death loss and loss due to placement in feedlots (the latter resulting in the majority of the loss from the matrix).

In order to ensure a balanced population of both stockers and placements, additional data tables are utilized in the stocker matrix calculations. The tables summarize the placement data by weight class and month, and is based on the total number of animals within the population that are available to be placed in feedlots and the actual feedlot placement statistics provided by USDA (2013). In cases where there are discrepancies between the USDA estimated placements by weight class and the calculated animals available by weight, the model pulls available stockers from one higher weight category if available. If there are still not enough animals to fulfill requirements the model pulls animals from one lower weight category. In the current time series, this method was able to ensure that total placement data matched USDA estimates, and no shortfalls have occurred.

In addition, average weights were tracked for each monthly age group using starting weight and monthly weight gain estimates. Weight gain (i.e., pounds per month) was estimated based on weight gain needed to reach a set target weight, divided by the number of months remaining before target weight was achieved. Birth weight was assumed to be 88 pounds for both beef and dairy animals. Weaning weights were estimated at 515 pounds. Other reported target weights were available for 12, 15, 24, and 36 month-old animals, depending on the animal type. Beef cow mature weight was taken from measurements provided by a major British Bos taurus breed (Enns 2008) and increased during the time series through 2007.[68] Bull mature weight was calculated as 1.5 times the beef cow mature weight (Doren et al. 1989). Beef replacement weight was calculated as 70 percent of mature weight at 15 months and 85 percent of mature weight at 24 months. As dairy weights are not a trait that is typically tracked, mature weight for dairy cows was estimated at 1,500 pounds for all years, based on a personal communication with Kris Johnson (2010) and an estimate from Holstein Association USA (2010).[69] Dairy replacement weight at 15 months was assumed to be 875 pounds and 1,300 pounds at 24 months. Live slaughter weights were estimated from dressed slaughter weight (USDA 2013) divided by 0.63. This ratio represents the dressed weight (i.e., weight of the carcass after removal of the internal organs), to the live weight (i.e., weight taken immediately before slaughter). The annual typical animal mass for each livestock type are presented in Table A-182.

Weight gain for stocker animals was based on monthly gain estimates from Johnson (1999) for 1989, and from average daily estimates from Lippke et al. (2000), Pinchack et al. (2004), Platter et al. (2003), and Skogerboe et al. (2000) for 2000. Interim years were calculated linearly, as shown in Table A-183, and weight gain was held constant starting in 2000. Table A-183 provides weight gains that vary by year in the CEFM.

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[68] Mature beef weight is held constant after 2007 but future inventory submissions will incorporate known trends through 2007 and extrapolate to future years, as noted in the Planned Improvements section.

[69] Mature dairy weight is based solely on Holstein weight, so could be higher than the national average. Future inventory submissions will consider other dairy breeds, as noted in the Planned Improvements section.

Table A-182: Typical Animal Mass (lbs)

Year/Cattle Type	Calves	Dairy Cows[a]	Dairy Replacements[b]	Beef Cows[a]	Bulls[a]	Beef Replacements[b]	Steer Stockers[b]	Heifer Stockers[b]	Steer Feedlot[b]	Heifer Feedlot[b]
1990	269	1,500	900	1,221	1,832	820	692	652	923	846
1991	270	1,500	898	1,225	1,838	822	695	656	934	856
1992	269	1,500	897	1,263	1,895	841	714	673	984	878
1993	270	1,500	899	1,280	1,920	852	721	683	983	878
1994	270	1,500	898	1,280	1,920	854	721	689	1000	886
1995	270	1,500	898	1,282	1,923	858	735	701	1019	896
1996	269	1,500	898	1,285	1,928	859	739	707	1018	893
1997	270	1,500	900	1,286	1,929	861	737	708	1010	888
1998	270	1,500	897	1,296	1,944	866	736	710	1046	905
1999	270	1,500	899	1,292	1,938	862	731	709	1050	908
2000	270	1,500	897	1,272	1,908	849	720	702	1063	915
2001	270	1,500	898	1,272	1,908	850	726	707	1081	918
2002	270	1,500	897	1,276	1,914	852	726	708	1088	933
2003	270	1,500	900	1,308	1,962	872	719	702	1087	929
2004	270	1,500	897	1,323	1,985	878	719	702	1089	921
2005	270	1,500	895	1,327	1,991	880	718	706	1087	934
2006	270	1,500	898	1,341	2,012	890	725	713	1113	943
2007	270	1,500	897	1,348	2,022	895	721	707	1133	954
2008	270	1,500	898	1,348	2,022	895	721	705	1142	961
2009	270	1,500	897	1,348	2,022	894	731	715	1145	966
2010	270	1,500	898	1,348	2,022	897	727	714	1134	964
2011	270	1,500	897	1,348	2,022	892	723	714	1137	955
2012	270	1,500	899	1,348	2,022	893	715	708	1153	969

[a] Input into the model.

[b] Annual average calculated in model based on age distribution.

Table A-183: Weight Gains that Vary by Year (lbs)

Year/Cattle Type	Steer Stockers to 12 months(lbs/day)	Steer Stockers to 24 months (lbs/day)	Heifer Stockers to 12 months(lbs/day)	Heifer Stockers to 24 months(lbs/day)
1990	1.53	1.23	1.23	1.08
1991	1.56	1.29	1.29	1.15
1992	1.59	1.35	1.35	1.23
1993	1.62	1.41	1.41	1.30
1994	1.65	1.47	1.47	1.38
1995	1.68	1.53	1.53	1.45
1996	1.71	1.59	1.59	1.53
1997	1.74	1.65	1.65	1.60
1998	1.77	1.71	1.71	1.68
1999	1.80	1.77	1.77	1.75
2000 onwards	1.83	1.83	1.83	1.83

Sources: Enns (2008), Johnson (1999), Lippke et al. (2000), NRC (1999), Pinchack et al. (2004), Platter et al. (2003), Skogerboe et al. (2000).

Feedlot Animals. Feedlot placement statistics from USDA provide data on the placement of animals from the stocker population into feedlots on a monthly basis by weight class. The model uses these data to shift a sufficient number of animals from the stocker cohorts into the feedlot populations to match the reported placement data. After animals are placed in feedlots they progress through two steps. First, animals spend 25 days on a step-up diet to become acclimated to the new feed type (e.g., more grain than forage, along with new dietary supplements), during this time weight gain is estimated to be 2.7 to 3 pounds per day (Johnson 1999). Animals are then switched to a finishing diet (concentrated, high energy) for a period of time before they are slaughtered. Weight gain during finishing diets is estimated to be 2.9 to 3.3 pounds per day (Johnson 1999). The length of time an animal spends in a feedlot depends on the start weight (i.e., placement weight), the rate of weight gain during the start-up and finishing phase of diet, and the target weight (as determined by weights at slaughter). Additionally, animals remaining in feedlots at the end of the year are tracked for inclusion in the following year's emission and population counts. For 1990 to 1995, only the total placement data were available, therefore placements for each weight category (categories displayed in Table A-184) for those years are based on the average of monthly placements from the 1996 to 1998 reported figures. Placement data is available by weight class for all years from 1996 onward. Table A-184 provides a summary of the reported feedlot placement statistics for 2012.

Table A-184: Feedlot Placements in the United States for 2012 (Number of animals placed in 1,000 Head)

Weight Placed When:	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
< 600 lbs	445	400	390	355	520	460	500	482	515	680	655	495
600 – 700 lbs	430	335	300	250	365	320	325	385	355	505	450	415
700 – 800 lbs	525	469	500	380	530	390	470	475	444	435	385	379
> 800 lbs	447	510	602	536	669	494	627	665	690	560	453	375
Total	**1,847**	**1,714**	**1,792**	**1,521**	**2,084**	**1,664**	**1,922**	**2,007**	**2,004**	**2,180**	**1,943**	**1,664**

Source: USDA (2013).

Note: Totals may not sum due to independent rounding.

Mature Animals. Energy requirements and hence, composition of diets, level of intake, and emissions for particular animals, are greatly influenced by whether the animal is pregnant or lactating. Information is therefore needed on the percentage of all mature animals that are pregnant each month, as well as milk production, to estimate CH_4 emissions. A weighted average percent of pregnant cows each month was estimated using information on births by month and average pregnancy term. For beef cattle, a weighted average total milk production per animal per month was estimated using information on typical lactation cycles and amounts (NRC 1999), and data on births by month. This process results in a range of weighted monthly lactation estimates expressed as pounds per animal per month. The monthly estimates for daily milk production by beef cows are shown in Table A-9. Annual estimates for dairy cows were taken from USDA milk production statistics. Dairy lactation estimates for 1990 through 2012 are shown in Table A-186. Beef and dairy cow and bull populations are assumed to remain relatively static throughout the year, as large fluctuations in population size are assumed to not occur. These estimates are taken from the USDA beginning and end of year population datasets.

Table A-185: Estimates of Monthly Milk Production by Beef Cows (Pounds per Head)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Beef Cow Milk Production (lbs/ head)	3.3	5.1	8.7	12.0	13.6	13.3	11.7	9.3	6.9	4.4	3.0	2.8

Table A-186: Dairy Lactation Rates by State (lbs/ year/cow)

State/Year	1990	1995	2000	2005	2009	2010	2011	2012
Alabama	12,214	14,176	13,920	14,000	14,909	14,455	13,182	13,200
Alaska	13,300	17,000	14,500	12,273	10,000	11,833	13,800	14,250
Arizona	17,500	19,735	21,820	22,679	23,028	23,441	23,468	23,979
Arkansas	11,841	12,150	12,436	13,545	12,692	12,750	11,833	13,300
California	18,456	19,573	21,130	21,404	22,000	23,025	23,438	23,457
Colorado	17,182	18,687	21,618	22,577	23,081	23,664	23,430	23,978
Connecticut	15,606	16,438	17,778	19,200	18,579	19,158	19,000	19,889
Delaware	13,667	14,500	14,747	16,622	17,000	16,981	18,300	19,143
Florida	14,033	14,698	15,688	16,591	18,070	18,658	19,067	19,008
Georgia	12,973	15,550	16,284	17,259	18,182	17,671	18,354	19,125
Hawaii	13,604	13,654	14,358	12,889	14,200	13,316	14,421	14,200
Idaho	16,475	18,147	20,816	22,332	22,091	22,658	22,934	23,376
Illinois	14,707	15,887	17,450	18,827	18,873	19,170	19,357	19,510
Indiana	14,590	15,375	16,568	20,295	20,137	20,094	20,657	21,366
Iowa	15,118	16,124	18,298	20,641	20,367	20,724	21,309	21,730
Kansas	12,576	14,390	16,923	20,505	21,085	20,975	21,016	21,675
Kentucky	10,947	12,469	12,841	12,896	14,190	14,769	14,342	15,135
Louisiana	11,605	11,908	12,034	12,400	11,870	11,750	12,889	13,176
Maine	14,619	16,025	17,128	18,030	18,061	18,344	18,688	18,576
Maryland	13,461	14,725	16,083	16,099	18,255	18,537	18,654	19,196
Massachusetts	14,871	16,000	17,091	17,059	17,571	17,286	16,923	18,250
Michigan	15,394	17,071	19,017	21,635	22,445	23,277	23,164	23,704
Minnesota	14,127	15,894	17,777	18,091	19,230	19,366	18,996	19,508
Mississippi	12,081	12,909	15,028	15,280	13,889	13,118	14,571	14,357
Missouri	13,632	14,158	14,662	16,026	14,654	14,596	14,611	14,936
Montana	13,542	15,000	17,789	19,579	19,933	20,643	20,571	21,357
Nebraska	13,866	14,797	16,513	17,950	19,672	19,797	20,579	21,179
Nevada	16,400	18,128	19,000	21,680	21,821	23,500	23,138	22,966
New Hampshire	15,100	16,300	17,333	18,875	19,533	19,600	20,429	19,643
New Jersey	13,538	13,913	15,250	16,000	17,889	17,500	16,875	18,571
New Mexico	18,815	18,969	20,944	21,192	24,320	24,551	24,854	24,694
New York	14,658	16,501	17,378	18,639	20,071	20,807	21,046	21,633
North Carolina	15,220	16,314	16,746	18,741	19,644	19,636	20,089	20,435
North Dakota	12,624	13,094	14,292	14,182	16,739	18,286	18,158	19,278
Ohio	13,767	15,917	17,027	17,567	18,744	19,446	19,194	19,833
Oklahoma	12,327	13,611	14,440	16,480	16,983	17,125	17,415	17,688
Oregon	16,273	17,289	18,222	18,876	19,719	20,331	20,488	20,431
Pennsylvania	14,726	16,492	18,081	18,722	19,360	19,847	19,495	19,576
Rhode Island	14,250	14,773	15,667	17,000	17,818	17,727	17,909	18,300
South Carolina	12,771	14,481	16,087	16,000	19,000	17,875	17,438	17,313
South Dakota	12,257	13,398	15,516	17,741	20,128	20,478	20,582	21,391
Tennessee	11,825	13,740	14,789	15,743	16,232	16,346	16,200	16,100
Texas	14,350	15,244	16,503	19,646	20,898	21,375	22,232	22,009
Utah	15,838	16,739	17,573	18,875	21,036	21,400	21,068	21,678
Vermont	14,528	16,210	17,199	18,469	18,289	18,537	18,940	19,316
Virginia	14,213	15,116	15,833	16,990	18,083	18,095	17,906	17,990
Washington	18,532	20,091	22,644	23,270	23,171	23,510	23,727	23,794
West Virginia	11,250	12,667	15,588	14,923	14,727	15,700	15,600	15,800
Wisconsin	13,973	15,397	17,306	18,500	20,079	20,630	20,599	21,436
Wyoming	12,337	13,197	13,571	14,878	19,036	20,067	20,517	20,817

Source: USDA (2013).

Step 2: Characterize U.S. Cattle Population Diets

To support development of digestible energy (DE, the percent of gross energy intake digested by the animal) and CH_4 conversion rate (Y_m, the fraction of gross energy converted to CH_4) values for each of the cattle population categories, data were collected on diets considered representative of different regions. For both grazing animals and animals being fed mixed rations, representative regional diets were estimated using information collected from state livestock specialists, the United States Department of Agriculture, expert opinion, and other literature sources. The designated regions for this analysis for dairy cattle for all years and foraging beef cattle from 1990 through 2006 are shown in Table A-187. For foraging beef cattle from 2007 onwards, the regional designations were revised based on data available from the NAHMS 2007-2008 survey on cow-calf system management practices (USDA:APHIS:VS 2010) and are shown in and Table A-

188. The data for each of the diets (e.g., proportions of different feed constituents, such as hay or grains) were used to determine feed chemical composition for use in estimating DE and Y_m for each animal type.

Table A-187: Regions used for Characterizing the Diets of Dairy Cattle (all years) and Foraging Cattle from 1990-2006

West	California	Northern Great Plains	Midwestern	Northeast	Southcentral	Southeast
Alaska	California	Colorado	Illinois	Connecticut	Arkansas	Alabama
Arizona		Kansas	Indiana	Delaware	Louisiana	Florida
Hawaii		Montana	Iowa	Maine	Oklahoma	Georgia
Idaho		Nebraska	Michigan	Maryland	Texas	Kentucky
Nevada		North Dakota	Minnesota	Massachusetts		Mississippi
New Mexico		South Dakota	Missouri	New Hampshire		North Carolina
Oregon		Wyoming	Ohio	New Jersey		South Carolina
Utah			Wisconsin	New York		Tennessee
Washington				Pennsylvania		Virginia
				Rhode Island		
				Vermont		
				West Virginia		

Source: USDA (1996).

Table A-188: Regions used for Characterizing the Diets of Foraging Cattle from 2007-2012

West	Central	Northeast	Southeast
Alaska	Illinois	Connecticut	Alabama
Arizona	Indiana	Delaware	**Arkansas**
California	Iowa	Maine	Florida
Colorado	**Kansas**	Maryland	Georgia
Hawaii	Michigan	Massachusetts	Kentucky
Idaho	Minnesota	New Hampshire	**Louisiana**
Montana	Missouri	New Jersey	Mississippi
Nevada	**Nebraska**	New York	North Carolina
New Mexico	**North Dakota**	Pennsylvania	**Oklahoma**
Oregon	Ohio	Rhode Island	South Carolina
Utah	**South Dakota**	Vermont	Tennessee
Washington	Wisconsin	West Virginia	**Texas**
Wyoming			Virginia

Source: Based on data from USDA:APHIS:VS (2010).
Note: States in **bold** represent a change in region from the 1990-2006 assessment.

DE and Y_m vary by diet and animal type. The IPCC recommends Y_m values of 3.0±1.0 percent for feedlot cattle and 6.5±1.0 percent for all other cattle (IPCC 2006). Given the availability of detailed diet information for different regions and animal types in the United States, DE and Y_m values unique to the United States were developed for dairy and beef cattle. Digestible energy and Y_m values were estimated across the time series for each cattle population category based on physiological modeling, published values, and/or expert opinion.

For dairy cows, ruminant digestion models were used to estimate Y_m. The three major categories of input required by the models are animal description (e.g., cattle type, mature weight), animal performance (e.g., initial and final weight, age at start of period), and feed characteristics (e.g., chemical composition, habitat, grain or forage). Data used to simulate ruminant digestion is provided for a particular animal that is then used to represent a group of animals with similar characteristics. The Y_m values were estimated for 1990 using the Donovan and Baldwin model (1999), which represents physiological processes in the ruminant animals, as well as diet characteristics from USDA (1996). The Donovan and Baldwin model is able to account for differing diets (i.e., grain-based or forage-based), so that Y_m values for the variable feeding characteristics within the U.S. cattle population can be estimated. Subsequently, a literature review of dairy diets was conducted and nearly 250 diets were analyzed from 1990 through 2009 across 23 states—the review indicated highly variable diets, both temporally and spatially. Kebreab et al. (2008) conducted an evaluation of models and found that the COWPOLL model was the best model for estimating Y_m for dairy. The statistical analysis of the COWPOLL model showed a trend in predicting Ym, and inventory team experts determined that the most comprehensive approach was to use the 1990 baseline from Donovan and Baldwin and then scale Y_m values for each of the diets beyond

1990 with the COWPOLL model. A function based on the national trend observed from the analysis of the dairy diets was used to calculate 1991 and beyond regional values based on the regional 1990 Y_m values from Donovan and Baldwin. The resulting scaling factor (incorporating both Donovan and Baldwin (1999) and COWPOLL) is shown below:

$$Y_m = Y_m(1990)EXP\left(\frac{1.22}{(Year-1980)}\right) / EXP\left(\frac{1.22}{(1990-1980)}\right)$$

DE values for dairy cows were estimated from the literature search based on the annual trends observed in the data collection effort. The regional variability observed in the literature search was not statistically significant, and therefore DE was not varied by region, but did vary over time, and was grouped by the following years 1990-1993, 1994-1998, 1999-2002[70], 2004-2006, 2007, and 2008 onwards.

Considerably less data was available for dairy heifers and dairy calves. Therefore, for dairy heifers assumptions were based on the relationship of the collected data in the literature on dairy heifers to the data on dairy cow diets. From this relationship, DE was estimated as the mature cow DE minus three percent, and Y_m was estimated as that of the mature dairy cow plus 0.1 percent.

To calculate the DE values for grazing beef cattle, diet composition assumptions were used to estimate weighted DE values for a combination of forage and supplemental diets. The forage portion makes up an estimated 85 to 95 percent of grazing beef cattle diets, and there is considerable variation of both forage type and quality across the US. Currently there is no comprehensive survey of this data, so for this analysis two regional DE values were developed to account for the generally lower forage quality in the "West" region of the United States versus all other regions in Table A-11 (California, Northern Great Plains, Midwestern, Northeast, Southcentral, Southeast) and Table A-12 (Central, Northeast, and Southeast). For all non-western grazing cattle, the forage DE was an average of the estimated seasonal values for grass pasture diets for a calculated DE of 64.2 percent. For foraging cattle in the west, the forage DE was calculated as the seasonal average for grass pasture, meadow and range diets, for a calculated DE of 61.3 percent. The assumed specific components of each of the broad forage types, along with their corresponding DE value and the calculated regional DE values can be found in Table A-189. In addition, it was assumed that each region fed a supplemental diet, and two sets of supplemental diets were developed, one for 1990 through 2006 (Donovan 1999) and one for 2007 onwards (Preston 2010, Archibeque 2011, USDA:APHIS:VS 2010) as shown in

Table A-190 and Table A-191 along with the percent of each total diet that is assumed to be made up of the supplemental portion. By weighting the calculated DE values from the forage and supplemental diets, the DE values for the composite diet were calculated.[71] These values are used for steer and heifer stockers and beef replacements. Finally, for mature beef cows and bulls, the DE value was adjusted downward by two percent to reflect the lower digestibility diets of mature cattle based on Johnson (2002). Y_m values for all grazing beef cattle were set at 6.5 percent based on Johnson (2002). The Y_m values and the resulting final weighted DE values by region for 2007 onwards are shown in Table A-192.

For feedlot animals, DE and Y_m are adjusted over time as diet compositions in actual feedlots are adjusted based on new and improved nutritional information and availability of feed types. Feedlot diets are assumed to not differ significantly by state, and therefore only a single set of national diet values is utilized for each year. The DE and Y_m values for 1990 were estimated by Dr. Don Johnson (1999). In the CEFM, the DE values for 1991 through 1999 were linearly extrapolated based on values for 1990 and 2000. DE and Y_m values from 2000 through the current year were estimated using the MOLLY model as described in Kebreab et al. (2008), based on a series of average diet feed compositions from Galyean and Gleghorn (2001) for 2000 through 2006 and Vasconcelos and Galyean (2007) for 2007 onwards. In addition, feedlot animals are assumed to spend the first 25 days in the feedlot on a "step-up" diet to become accustomed to the higher quality feedlot diets. The step-up DE and Y_m are calculated as the average of all state forage and feedlot diet DE and Y_m values.

For calves aged 4 through 6 months, a gradual weaning from milk is simulated, with calf diets at 4 months assumed to be 25 percent forage, increasing to 50 percent forage at age 5 months, and 75 percent forage at age 6 months. The portion of the diet allocated to milk results in zero emissions, as recommended by the IPCC (2006). For calves, the DE for the remainder of the diet is assumed to be similar to that of slightly older replacement heifers (both beef and dairy are calculated separately). The Y_m for beef calves is also assumed to be similar to that of beef replacement heifers (6.5 percent), as literature does not provide an alternative Y_m for use in beef calves. For dairy calves, the Y_m is assumed to be 7.8 percent at 4 months, 8.03 percent at 5 months, and 8.27 percent at 6 months per estimates provided by Soliva (2006)

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[70] Due to inconsistencies in the 2003 literature values, the 2002 values were extended to include 2003 as well.

[71] For example, the West has a forage DE of 61.3 which makes up 90 percent of the diet and a supplemented diet DE of 67.4 percent was used for 10 percent of the diet, for a total weighted DE of 61.9 percent, as shown in Table A-192.

for Y_m at 4 and 7 months of age. Estimates for 5 and 6 months are the result of linear interpolation between the values provided for 4 and 7 months.

Table A-193 shows the regional DE and Y_m for U.S. cattle in each region for 2012.

Table A-189: Feed Components and Digestible Energy Values Incorporated into Forage Diet Composition Estimates

Forage Type	DE, (% of GE)	Grass pasture - Spring	Grass pasture - Summer	Grass pasture - Fall	Range June	Range July	Range August	Range September	Range Winter	Meadow - Spring	Meadow - Fall
Bahiagrass Paspalum notatum, fresh	61.38			x							
Bermudagrass Cynodon dactylon, fresh	66.29		x								
Bremudagrass, Coastal Cynodon dactylon, fresh	65.53		x								
Bluegrass, Canada Poa compressa, fresh, early vegetative	73.99	x									
Bluegrass, Kentucky Poa pratensis, fresh, early vegetative	75.62	x									
Bluegrass, Kentucky Poa pratensis, fresh, mature	59.00		x	x							
Bluestem Andropagon spp, fresh, early vegetative	73.17				x						
Bluestem Andropagon spp, fresh, mature	56.82					x	x	x	x		x
Brome Bromus spp, fresh, early vegetative	78.57	x									
Brome, Smooth Bromus inermis, fresh, early vegetative	75.71	x									
Brome, Smooth Bromus inermis, fresh, mature	57.58		x	x					x		
Buffalograss, Buchloe dactyloides, fresh	64.02				x	x					
Clover, Alsike Trifolium hybridum, fresh, early vegetative	70.62	x									
Clover, Ladino Trifolium repens, fresh, early vegetative	73.22	x									
Clover, Red Trifolium pratense, fresh, early bloom	71.27	x									
Clover, Red Trifolium pratense, fresh, full bloom	67.44		x		x						
Corn, Dent Yellow Zea mays indentata, aerial part without ears, without husks, sun-cured, (stover)(straw)	55.28			x							
Dropseed, Sand Sporobolus cryptandrus, fresh, stem cured	64.69				x	x	x			x	
Fescue Festuca spp, hay, sun-cured, early vegetative	67.39	x									
Fescue Festuca spp, hay, sun-cured, early bloom	53.57			x							
Grama Bouteloua spp, fresh, early vegetative	67.02	x									
Grama Bouteloua spp, fresh, mature	63.38		x	x						x	
Millet, Foxtail Setaria italica, fresh	68.20	x			x						
Napiergrass Pennisetum purpureum, fresh, late bloom	57.24		x	x							
Needleandthread Stipa comata, fresh, stem cured	60.36					x	x	x			
Orchardgrass Dactylis glomerata, fresh, early vegetative	75.54	x									
Orchardgrass Dactylis glomerata, fresh, midbloom	60.13		x								
Pearlmillet Pennisetum glaucum, fresh	68.04	x									
Prairie plants, Midwest, hay, sun-cured	55.53			x							x
Rape Brassica napus, fresh, early bloom	80.88	x									
Rye Secale cereale, fresh	71.83	x									
Ryegrass, Perennial Lolium perenne, fresh	73.68	x									
Saltgrass Distichlis spp, fresh, post ripe	58.06		x	x							
Sorghum, Sudangrass Sorghum bicolor sudanense, fresh, early vegetative	73.27	x									
Squirreltail Stanion spp, fresh, stem-cured	62.00		x			x					

Forage Type	DE, (% of GE)	Grass pasture - Spring	Grass pasture - Summer	Grass pasture - Fall	Range June	Range July	Range August	Range September	Range Winter	Meadow - Spring	Meadow - Fall
Summercypress, Gray Kochia vestita, fresh, stem-cured	65.11			x	x	x					
Timothy Phleum pratense, fresh, late vegetative	73.12	x									
Timothy Phleum pratense, fresh, midbloom	66.87		x								
Trefoil, Birdsfoot Lotus corniculatus, fresh	69.07	x									
Vetch Vicia spp, hay, sun-cured	59.44			x							
Wheat Triticum aestivum, straw	45.77			x							
Wheatgrass, Crested Agropyron desertorum, fresh, early vegetative	79.78	x									
Wheatgrass, Crested Agropyron desertorum, fresh, full bloom	65.89		x			x					
Wheatgrass, Crested Agropyron desertorum, fresh, post ripe	52.99			x					x		x
Winterfat, Common Eurotia lanata, fresh, stem-cured	40.89								x		
Weighted Average DE		**72.99**	**62.45**	**57.26**	**67.11**	**62.70**	**60.62**	**58.59**	**52.07**	**64.03**	**55.11**
Forage Diet for West	**61.3**	**10%**	**10%**	**10%**	**10%**	**10%**	**10%**	**10%**	**10%**	**10%**	**10%**
Forage Diet for All Other Regions	**64.2**	**33.3%**	**33.3%**	**33.3%**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

Sources: Preston (2010) and Archibeque (2011).

Note that forages marked with an x indicate that the DE from that a specific forage type is included in the general forage type for that column (e.g., grass pasture, range, meadow or meadow by month or season).

Table A-190: DE Values with Representative Regional Diets for the Supplemental Diet of Grazing Beef Cattle for 1990-2006

Feed	Source of DE (NRC 1984)	Unweighted DE (% of GE)	California[*]	West	Northern Great Plains	Southcentral	Northeast	Midwest	Southeast
Alfalfa Hay	Table 8, feed #006	61.79	65%	30%	30%	29%	12%	30%	
Barley		85.08	10%	15%					
Bermuda	Table 8, feed #030	66.29							35%
Bermuda Hay	Table 8, feed #031	50.79				40%			
Corn	Table 8, feed #089	88.85	10%	10%	25%	11%	13%	13%	
Corn Silage	Table 8, feed #095	72.88			25%		20%	20%	
Cotton Seed Meal						7%			
Grass Hay	Table 8, feed #126, 170, 274	58.37		40%				30%	
Orchard	Table 8, feed #147	60.13							40%
Soybean Meal Supplement		77.15		5%	5%				5%
Sorghum	Table 8, feed #211	84.23							20%
Soybean Hulls		66.86						7%	
Timothy Hay	Table 8, feed #244	60.51					50%		
Whole Cotton Seed		75.75	5%				5%		
Wheat Middlings	Table 8, feed #257	68.09			15%	13%			
Wheat	Table 8, feed #259	87.95	10%						
Weighted Supplement DE (%)			**70.1**	**67.4**	**73.0**	**62.0**	**67.6**	**66.9**	**68.0**
Percent of Diet that is Supplement			**5%**	**10%**	**15%**	**10%**	**15%**	**10%**	**5%**

Source of representative regional diets: Donovan (1999).

[*] Note that emissions are currently calculated on a state-by-state basis, but diets are applied by the regions shown in the table above.

Table A-191: DE Values and Representative Regional Diets for the Supplemental Diet of Grazing Beef Cattle for 2007-2012

Feed	Source of DE (NRC1984)	Unweighted DE (% of GE)	West[a]	Central[a]	Northeast[a]	Southeast[a]
Alfalfa Hay	Table 8, feed #006	61.79	65%	30%	12%	
Bermuda	Table 8, feed #030	66.29				20%
Bermuda Hay	Table 8, feed #031	50.79				20%
Corn	Table 8, feed #089	88.85	10%	15%	13%	10%
Corn Silage	Table 8, feed #095	72.88		35%	20%	
Grass Hay	Table 8, feed #126, 170, 274	58.37	10%			
Orchard	Table 8, feed #147	60.13				30%
Protein supplement (West)	Table 8, feed #082, 134, 225[b]	81.01	10%			
Protein Supplement (Central and Northeast)	Table 8, feed #082, 134, 225[b]	80.76		10%	10%	
Protein Supplement (Southeast)	Table 8, feed #082, 134, 101[b]	77.89				10%
Sorghum	Table 8, feed #211	84.23		5%		10%
Timothy Hay	Table 8, feed #244	60.51			45%	
Wheat Middlings	Table 8, feed #257	68.09		5%		
Wheat	Table 8, feed #259	87.95	5%			
Weighted Supplement DE			**67.4**	**73.1**	**68.9**	**66.6**
Percent of Diet that is Supplement			**10%**	**15%**	**5%**	**15%**

Sources of representative regional diets: Donovan (1999), Preston (2010), Archibeque (2011), and USDA:APHIS:VS (2010).

[a] Note that emissions are currently calculated on a state-by-state basis, but diets are applied by the regions shown in the table above.

[b] Not in equal proportions.

Table A-192: Foraging Animal DE (% of GE) and Y_m Values for Each Region and Animal Type for 2007-2012

Animal Type	Data	West[c]	Central	Northeast	Southeast
Beef Repl. Heifers	DE[a]	61.9	65.6	64.5	64.6
	Y_m[b]	6.5%	6.5%	6.5%	6.5%
Beef Calves (4-6 mo)	DE	61.9	65.6	64.5	64.6
	Y_m	6.5%	6.5%	6.5%	6.5%
Steer Stockers	DE	61.9	65.6	64.5	64.6
	Y_m	6.5%	6.5%	6.5%	6.5%
Heifer Stockers	DE	61.9	65.6	64.5	64.6
	Y_m	6.5%	6.5%	6.5%	6.5%
Beef Cows	DE	59.9	63.6	62.5	62.6
	Y_m	6.5%	6.5%	6.5%	6.5%
Bulls	DE	59.9	63.6	62.5	62.6
	Y_m	6.5%	6.5%	6.5%	6.5%

[a] DE is the digestible energy in units of percent of GE (MJ/Day).

[b] Y_m is the methane conversion rate, the fraction of GE in feed converted to methane.

[c] Note that emissions are currently calculated on a state-by-state basis, but diets are applied by the regions shown in the table above. To see the regional designation per state, please see Table A-188.

Table A-193: Regional DE (% of GE) and Y_m Rates for Dairy and Feedlot Cattle by Animal Type for 2012

Animal Type	Data	California[c]	West	Northern Great Plains	Southcentral	Northeast	Midwest	Southeast
Dairy Repl. Heifers	DE[a]	63.7	63.7	63.7	63.7	63.7	63.7	63.7
	Ym[b]	6.0%	6.0%	5.7%	6.5%	6.4%	5.7%	7.0%
Dairy Calves (4-6 mo)	DE	63.7	63.7	63.7	63.7	63.7	63.7	63.7
	Ym	7.8% (4 mo), 8.03% (5 mo), 8.27% (6 mo)-all regions						
Dairy Cows	DE	66.7	66.7	66.7	66.7	66.7	66.7	66.7
	Ym	5.9%	5.9%	5.6%	6.4%	6.3%	5.6%	6.9%
Steer Feedlot	DE	82.5	82.5	82.5	82.5	82.5	82.5	82.5
	Ym	3.9%	3.9%	3.9%	3.9%	3.9%	3.9%	3.9%
Heifer Feedlot	DE	82.5	82.5	82.5	82.5	82.5	82.5	82.5
	Ym	3.9%	3.9%	3.9%	3.9%	3.9%	3.9%	3.9%

[a] DE is the digestible energy in units of percent of GE (MJ/Day).

[b] Y_m is the methane conversion rate, the fraction of GE in feed converted to methane.

[c] Note that emissions are currently calculated on a state-by-state basis, but diets are applied in Table A-187 by the regions shown in the table above. To see the regional designation for foraging cattle per state, please see Table A-187.

Step 3: Estimate CH_4 Emissions from Cattle

Emissions by state were estimated in three steps: a) determine gross energy (GE) intake using the Tier 2 IPCC (2006) equations, b) determine an emission factor using the GE values, Y_m and a conversion factor, and c) sum the daily emissions for each animal type. Finally, the state emissions were aggregated to obtain the national emissions estimate. The necessary data values for each state and animal type include:

- Body Weight (kg)
- Weight Gain (kg/day)
- Net Energy for Activity (C_a, MJ/day)[72]
- Standard Reference Weight (kg)[73]
- Milk Production (kg/day)
- Milk Fat (percent of fat in milk = 4)
- Pregnancy (percent of population that is pregnant)
- DE (percent of GE intake digestible)
- Y_m (the fraction of GE converted to CH_4)
- Population

Step 3a: Determine Gross Energy, GE

As shown in the following equation, GE is derived based on the net energy estimates and the feed characteristics. Only variables relevant to each animal category are used (e.g., estimates for feedlot animals do not require the NE_l factor). All net energy equations are provided in IPCC (2006).

$$GE = \left[\frac{\left(\frac{NE_m + NE_a + NE_l + NE_{work} + NE_p}{REM} \right) + \left(\frac{NE_g}{REG} \right)}{\frac{DE\%}{100}} \right]$$

where,

GE = Gross energy (MJ/day)
NE_m = Net energy required by the animal for maintenance (MJ/day)
NE_a = Net energy for animal activity (MJ/day)
NE_l = Net energy for lactation (MJ/day)
NE_{work} = Net energy for work (MJ/day)
NE_p = Net energy required for pregnancy (MJ/day)
REM = Ratio of net energy available in a diet for maintenance to digestible energy consumed
NE_g = Net energy needed for growth (MJ/day)
REG = Ratio of net energy available for growth in a diet to digestible energy consumed
DE = Digestible energy expressed as a percent of gross energy (percent)

Step 3b: Determine Emission Factor

The daily emission factor (DayEmit) was determined using the GE value and the methane conversion factor (Y_m) for each category. This relationship is shown in the following equation:

$$DayEmit = \frac{GE \times Y_m}{55.65}$$

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[72] Zero for feedlot conditions, 0.17 for high quality confined pasture conditions, and 0.36 for extensive open range or hilly terrain grazing conditions. C_a factor for dairy cows is weighted to account for the fraction of the population in the region that grazes during the year (IPCC 2006).

[73] Standard Reference Weight is the mature weight of a female animal of the animal type being estimated, used in the model to account for breed potential.

where,

DayEmit = Emission factor (kg CH_4/head/day)
GE = Gross energy intake (MJ/head/day)
Y_m = CH_4 conversion rate, which is the fraction of GE in feed converted to CH_4 (%)
55.65 = A factor for the energy content of methane (MJ/kg CH_4)

The daily emission factors were estimated for each animal type and state, calculated annual national emission factors are shown by animal type in Table A-194.

Table A-194: Calculated Annual National Emission Factors for Cattle by Animal Type (kg CH_4/head/year)

Cattle Type	1990	1995	2000	2005	2009	2010	2011	2012
Dairy								
Calves	12	12	12	12	12	12	12	12
Cows	124	125	132	133	140	142	142	143
Replacements 7-11 months	48	46	46	45	46	46	46	46
Replacements 12-23 months	73	69	70	67	70	69	69	69
Beef								
Calves	11	11	11	11	11	11	11	11
Bulls	91	94	94	97	98	98	98	98
Cows	89	92	91	94	95	95	95	95
Replacements 7-11 months	54	57	56	59	60	60	60	60
Replacements 12-23 months	63	66	66	68	70	70	70	70
Steer Stockers	55	57	58	58	58	58	58	58
Heifer Stockers	52	56	60	60	60	60	60	60
Feedlot Cattle	39	39	41	41	46	46	45	46

Note: To convert to a daily emission factor, the yearly emission factor can be divided by 365 (the number of days in a year).

For quality assurance purposes, U.S. emission factors for each animal type were compared to estimates provided by the other Annex I member countries of the United Nations Framework Convention on Climate Change (UNFCCC) (the most recently available summarized results for Annex I countries are through 2011 only). Results, presented in Table A-195 indicate that U.S. emission factors are comparable to those of other Annex I countries. Results are presented in Table A-195 (along with Tier I emission factors provided by IPCC (2006). Throughout the time series, beef cattle in the United States generally emit more enteric CH_4 than other Annex I member countries, while dairy cattle in the United States generally emit comparable enteric CH_4.

Table A-195: Annex I Countries' Implied Emission Factors for Cattle by Year (kg CH_4/head/year)

	Dairy Cattle		Beef Cattle	
Year	United States Implied Emission Factor	Mean of Implied Emission Factors for Annex I countries (excluding U.S.)	United States Implied Emission Factor	Mean of Implied Emission Factors for Annex I countries (excluding U.S.)
1990	107	96	71	53
1991	107	97	71	53
1992	107	96	72	54
1993	106	97	73	54
1994	106	98	73	54
1995	106	98	73	54
1996	105	99	73	54
1997	106	100	73	54
1998	107	101	73	55
1999	110	102	73	55
2000	111	103	73	55
2001	110	104	73	55
2002	111	105	73	55
2003	111	106	74	55
2004	109	107	74	55

2005	110	109	74	55
2006	110	110	74	55
2007	114	111	75	55
2008	115	112	76	55
2009	115	112	76	56
2010	115	113	75	55
2011	116	113	75	55
2012	117	N/A	75	N/A
Tier I EFs For North America, from IPCC (2006)		121	53	

Step 3c: Estimate Total Emissions

Emissions were summed for each month and for each state population category using the daily emission factor for a representative animal and the number of animals in the category. The following equation was used:

$$\text{Emissions}_{\text{state}} = \text{DayEmit}_{\text{state}} \times \text{Days/Month} \times \text{SubPop}_{\text{state}}$$

where,

$\text{Emissions}_{\text{state}}$ = Emissions for state during the month (kg CH_4)
$\text{DayEmit}_{\text{state}}$ = Emission factor for the subcategory and state (kg CH_4/head/day)
Days/Month = Number of days in the month
$\text{SubPop}_{\text{state}}$ = Number of animals in the subcategory and state during the month

This process was repeated for each month, and the monthly totals for each state subcategory were summed to achieve an emission estimate for a state for the entire year and state estimates were summed to obtain the national total. The estimates for each of the 10 subcategories of cattle are listed in Table A-196. The emissions for each subcategory were then aggregated to estimate total emissions from beef cattle and dairy cattle for the entire year.

Table A-196: CH_4 Emissions from Cattle (Gg)

Cattle Type	1990	1995	2000	2005	2009	2010	2011	2012
Dairy	**1,574**	**1,498**	**1,519**	**1,503**	**1,639**	**1,626**	**1,643**	**1,668**
Calves (4-6 months)	62	59	59	54	58	57	57	58
Cows	1,242	1,185	1,209	1,197	1,304	1,287	1,301	1,324
Replacements 7-11 months	58	56	55	56	61	62	63	62
Replacements 12-23 months	212	202	196	196	216	221	222	224
Beef	**4,763**	**5,438**	**5,098**	**5,037**	**5,062**	**5,019**	**4,911**	**4,789**
Calves (4-6 months)	182	193	186	179	169	169	166	160
Bulls	196	225	215	214	216	215	211	205
Cows	2,884	3,222	3,058	3,056	3,002	2,970	2,921	2,855
Replacements 7-11 months	69	85	74	80	78	75	74	75
Replacements 12-23 months	188	241	204	217	216	213	202	207
Steer Stockers	563	662	509	473	491	475	439	415
Heifer Stockers	306	375	323	299	300	301	283	267
Feedlot Cattle	375	435	530	518	592	602	615	604
Total	**6,338**	**6,936**	**6,617**	**6,540**	**6,701**	**6,645**	**6,555**	**6,458**

Notes: Totals may not sum due to independent rounding.

Emission Estimates from Other Livestock

"Other livestock" include horses, sheep, swine, goats, American bison, and mules and asses. All livestock population data, except for American bison for years prior to 2002, were taken from the U.S. Department of Agriculture (USDA) National Agricultural Statistics Service (NASS) agricultural statistics database (USDA 2013) or earlier census data (USDA 1992, 1997). The Manure Management Annex discusses the methods for obtaining annual average populations and disaggregating into state data where needed and provides the resulting population data for the other livestock that were used for estimating all livestock-related emissions (See Table A-199). For each animal category, the USDA publishes monthly, annual, or multi-year livestock population and production estimates. All data were downloaded from the USDA-NASS agricultural database (USDA 2013) or taken from older census reports (USDA 1992, 1997). American bison estimates prior to 2002 were estimated using data from the National Bison Association (1999).

Methane emissions from sheep, goats, swine, horses, mules and asses were estimated by multiplying national population estimates by the default IPCC emission factor (IPCC 2006). For American bison the emission factor for buffalo (IPCC 2006) was used and adjusted based on the ratio of live weights of 300 kg for buffalo (IPCC 2006) and 1,130 pounds (513 kg) for American Bison (National Bison Association 2011) to the 0.75 power. This methodology for determining emission factors is recommended by IPCC (2006) for animals with similar digestive systems. Table A-197 shows the emission factors used for these other livestock.

National enteric fermentation emissions from all livestock types are shown in Table A-198 and Table A-199. Enteric fermentation emissions from most livestock types, broken down by state, for 2012 are shown in Table A-200 and Table A-201. Livestock Populations are shown in Table A- 202.

Table A-197: Emission Factors for Other Livestock (kg CH_4/head/year)

Livestock Type	Emission Factor
Sheep	8
Goats	5
Horses	18
Swine	1.5
Mules and Asses	10.0
American Bison	82.2

Source: IPCC (2006), except American Bison, as described in text.

Table A-198: CH_4 Emissions from Enteric Fermentation (Tg CO_2 Eq.)

Livestock Type	1990	1995	2000	2006	2007	2008	2009	2010	2011	2012
Beef Cattle	100.0	114.2	107.1	107.5	108.4	107.5	106.3	105.4	103.1	100.6
Dairy Cattle	33.1	31.5	31.9	32.2	33.6	34.1	34.4	34.1	34.5	35.0
Horses	0.8	1.0	1.3	1.5	1.5	1.6	1.6	1.6	1.6	1.7
Sheep	1.9	1.5	1.2	1.0	1.0	1.0	1.0	0.9	0.9	0.9
Swine	1.7	1.9	1.9	1.9	2.1	2.1	2.1	2.0	2.1	2.1
Goats	0.3	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
American Bison	0.1	0.2	0.3	0.4	0.3	0.3	0.3	0.3	0.3	0.3
Mules and Asses	+	+	+	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**137.9**	**1,150.5**	**1,143.9**	**144.9**	**147.4**	**147.0**	**146.1**	**144.9**	**143.0**	**141.0**

Notes: Totals may not sum due to independent rounding.
+ indicates emissions are less than 0.05.

Table A-199: CH_4 Emissions from Enteric Fermentation (Gg)

Livestock Type	1990	1995	2000	2006	2007	2008	2009	2010	2011	2012
Beef Cattle	4,763	5,438	5,098	5,117	5,163	5,119	5,062	5,019	4,911	4,789
Dairy Cattle	1,574	1,498	1,519	1,534	1,601	1,622	1,639	1,626	1,643	1,668
Horses	40	47	61	71	73	74	75	77	78	79
Sheep	91	72	56	50	49	48	46	45	44	43
Swine	81	88	88	93	98	101	99	97	98	100
Goats	13	12	12	15	16	16	16	16	16	16
American Bison	4	9	16	17	16	16	15	15	14	14
Mules and Asses	1	1	1	2	3	3	4	4	4	5
Total	**6,566**	**7,165**	**6,852**	**6,899**	**7,019**	**6,999**	**6,956**	**6,898**	**6,809**	**6,714**

Note: Totals may not sum due to independent rounding.

Table A-200: CH_4 Emissions from Enteric Fermentation from Cattle (Gg), by State, for 2012

State	Dairy Calves	Dairy Cows	Dairy Repl. Heif. 0-12	Dairy Repl. Heif. 12-24	Bulls	Beef Calves	Beef Cows	Beef Repl. Heif. 0-12	Beef Repl. Heif. 12-24	Steer Stockers	Heifer Stockers	Feedlot	**Total**
Alabama	63	1,312	93	337	4,379	3,426	61,173	1,348	3,695	1,440	1,101	492	78,860
Alaska	3	57	3	10	301	31	553	24	67	11	3	3	1,066
Arizona	1,203	28,933	937	3,390	2,078	1,024	18,084	536	1,461	8,455	456	11,191	77,748
Arkansas	70	1,306	72	260	5,839	4,791	85,548	1,632	4,473	2,880	1,693	-	108,564
California	11,270	265,624	11,240	40,681	7,272	3,528	62,291	1,684	4,591	17,192	6,689	20,456	452,518
Colorado	829	18,872	950	3,440	5,194	4,318	76,256	2,373	6,470	26,210	15,507	46,929	207,348
Conn.	117	2,668	134	487	59	24	425	36	98	63	14	15	4,139
Delaware	32	706	47	169	39	19	330	10	27	63	14	15	1,470
Florida	760	18,932	544	1,967	5,839	4,955	88,465	1,632	4,473	524	847	261	129,199
Georgia	494	12,347	481	1,742	2,627	2,699	48,185	1,008	2,762	890	903	345	74,485
Hawaii	12	216	13	48	519	444	7,847	153	417	169	182	63	10,085
Idaho	3,679	87,096	4,014	14,529	3,636	2,668	47,120	1,378	3,756	8,455	5,777	9,626	191,735
Illinois	627	12,615	596	2,156	2,378	1,700	30,454	775	2,126	5,362	3,219	6,418	68,425
Indiana	1,108	23,508	887	3,210	1,998	1,001	17,941	429	1,177	2,528	1,623	4,292	59,703
Iowa	1,298	27,816	2,028	7,338	5,708	4,596	82,345	1,936	5,315	33,196	17,059	52,143	240,779
Kansas	779	16,664	1,077	3,898	8,562	7,430	133,132	3,458	9,492	48,773	42,648	95,061	370,975
Kentucky	475	10,502	699	2,529	6,812	5,244	93,642	1,916	5,251	5,237	4,093	401	136,801
Louisiana	114	2,127	86	312	2,725	2,382	42,539	1,150	3,151	602	677	246	56,110
Maine	203	4,440	227	820	146	53	944	43	117	144	85	44	7,265
Maryland	329	7,349	396	1,435	390	227	4,058	171	468	420	227	401	15,872
Mass.	76	1,649	85	307	98	37	661	43	117	53	28	16	3,168
Michigan	2,349	53,067	2,002	7,246	1,617	560	10,029	373	1,025	4,418	1,238	6,017	89,942
Minnesota	2,944	59,246	3,612	13,071	3,330	1,874	33,582	1,245	3,417	11,874	5,090	12,434	151,719
Miss.	89	1,910	109	393	3,795	2,562	45,738	1,164	3,190	1,597	1,016	507	62,071
Missouri	589	10,266	507	1,835	9,513	9,536	170,854	3,734	10,251	9,193	6,604	2,206	235,087
Montana	89	1,880	101	367	9,350	8,284	146,282	6,354	17,322	5,918	6,446	1,284	203,677
Nebraska	355	7,484	190	688	9,513	9,674	173,338	5,325	14,617	58,221	39,071	106,292	424,769
Nevada	184	4,300	134	484	1,454	1,343	23,711	628	1,711	1,184	1,125	281	36,538
N. Hamp.	89	2,005	92	333	49	21	377	21	59	39	14	10	3,110
N. Jersey	47	1,040	57	205	98	42	755	28	78	53	42	18	2,464
N. Mexico	2,121	51,957	1,606	5,812	3,636	2,475	43,704	1,148	3,130	3,100	2,737	1,046	122,471
New York	3,862	92,408	4,530	16,396	1,464	529	9,437	541	1,483	1,051	1,189	1,003	133,892
N. Car.	285	7,393	326	1,180	3,309	1,898	33,880	923	2,528	1,021	734	340	53,817
N. Dakota	114	2,278	127	459	5,423	4,426	79,309	2,531	6,948	6,512	5,503	2,407	116,035
Ohio	1,710	34,729	1,521	5,504	2,378	1,541	27,602	761	2,088	4,852	1,926	7,220	91,830
Oklahoma	329	7,136	287	1,039	11,677	9,372	167,331	4,542	12,447	24,091	13,266	15,242	266,760
Oregon	779	17,013	1,004	3,632	4,155	3,112	54,956	1,684	4,591	4,368	2,889	2,808	100,991
Penn	3,419	77,175	4,459	16,140	2,440	846	15,100	641	1,756	3,809	1,557	3,008	130,349
R.Island	7	151	7	26	10	7	123	4	12	8	3	2	359
S. Car.	101	2,400	93	337	1,557	970	17,317	511	1,400	288	423	136	25,534
S. Dakota	570	12,098	444	1,605	8,562	8,267	148,129	4,426	12,149	17,620	14,858	12,835	241,563
Tenn.	317	7,222	466	1,686	6,812	5,007	89,406	2,129	5,835	4,190	2,822	361	126,254
Texas	2,754	67,646	3,015	10,911	32,113	24,061	429,622	7,806	21,393	62,061	42,901	118,325	822,611
Utah	570	12,890	709	2,567	2,078	1,878	33,155	995	2,713	2,536	1,429	1,043	62,562
Vermont	842	18,863	764	2,767	293	53	944	57	156	105	142	47	25,033
Virginia	608	14,698	621	2,248	3,892	3,500	62,490	1,348	3,695	4,190	1,552	923	99,766
Wash.	1,665	39,858	1,606	5,812	1,974	1,235	21,802	827	2,254	5,073	3,375	9,426	94,905
W. Virg.	63	1,272	71	256	1,366	1,031	18,403	513	1,404	1,130	736	201	26,446
Wisconsin	8,009	170,261	8,744	31,646	2,854	1,361	24,381	968	2,658	9,193	1,101	9,626	270,802
Wyoming	38	794	63	229	4,155	4,062	71,735	2,526	6,887	5,073	4,257	3,008	102,828

Table A-201: CH_4 Emissions from Enteric Fermentation from Other Livestock (Gg), by State, for 2012

State	Horses	Sheep	Swine	Goats	American bison	Mules and Asses	Total
AK-Alaska	0.05	0.10	0.00	0.01	0.14	0.00	0.3
AL-Alabama	1.96	0.10	0.21	0.00	0.02	0.18	2.5
AR-Arkansas	1.54	0.10	0.17	0.21	0.05	0.12	2.2
AZ-Arizona	1.63	1.12	0.26	0.25	0.03	0.04	3.3
CA-California	4.13	4.56	0.16	0.65	0.25	0.12	9.9
CO-Colorado	2.36	3.68	1.09	0.24	1.54	0.08	9.0
CT-Conn.	0.24	0.06	0.00	0.02	0.01	0.01	0.3
DE-Delaware	0.08	0.10	0.01	0.02	-	0.00	0.2
FL-Florida	2.54	0.10	0.02	0.29	0.13	0.11	3.2
GA-Georgia	1.43	0.10	0.23	0.42	0.05	0.15	2.4
HI-Hawaii	0.15	0.10	0.02	0.05	0.01	0.00	0.3
IA-Iowa	1.20	1.56	30.56	0.24	0.25	0.06	33.9
ID-Idaho	1.17	1.92	0.05	0.28	-	0.06	3.5
IL-Illinois	1.79	0.46	6.99	0.09	0.13	0.07	9.5
IN-Indiana	1.15	0.44	5.66	0.17	0.15	0.07	7.6
KS-Kansas	2.02	0.56	2.78	0.25	0.93	0.07	6.6
KY-Kentucky	3.63	0.32	0.47	0.49	0.01	0.19	5.1
LA-Louisiana	1.32	0.10	0.01	0.11	0.01	0.08	1.6
MA-Mass.	0.46	0.06	0.02	0.03	0.00	0.02	0.6
MD-Maryland	0.64	0.10	0.03	0.08	0.10	0.02	1.0
ME-Maine	0.21	0.06	0.01	0.04	0.03	0.01	0.4
MI-Michigan	1.75	0.63	1.56	0.14	0.26	0.07	4.4
MN-Minnesota	1.58	1.20	11.74	0.18	0.02	0.06	14.8
MO-Missouri	2.83	0.66	4.16	0.15	0.17	0.19	8.2
MS-Mississippi	1.15	0.10	0.62	0.48	-	0.12	2.5
MT-Montana	2.09	1.80	0.26	0.06	0.79	0.06	5.1
NC-North Carolina	1.67	0.21	13.46	0.06	0.05	0.15	15.6
ND-North Dakota	0.83	0.58	0.20	0.20	0.07	0.01	1.9
NE-Nebraska	1.30	0.62	4.67	0.49	1.75	0.04	8.9
NH-New Hampshire	0.21	0.06	0.00	0.17	0.00	0.01	0.5
NJ-New Jersey	0.60	0.10	0.01	0.02	0.01	0.02	0.8
NM-New Mexico	1.09	0.80	0.00	0.05	0.31	0.03	1.0
NV-Nevada	0.37	0.56	0.00	0.02	0.02	0.01	2.3
NY-New York	1.71	0.50	0.10	0.18	0.13	0.04	2.7
OH-Ohio	1.87	1.01	3.18	0.35	-	0.10	6.5
OK-Oklahoma	3.26	0.56	3.48	0.63	0.60	0.22	8.7
OR-Oregon	1.56	1.60	0.02	0.19	0.04	0.07	3.5
PA-Penn.	2.15	0.71	1.67	0.30	0.16	0.16	5.1
RI-Rhode Island	0.09	0.06	0.00	0.00	-	0.00	0.2
SC-South Carolina	0.83	0.10	0.36	0.22	0.01	0.08	1.6
SD-South Dakota	1.28	2.28	1.91	0.05	3.06	0.03	8.6
TN-Tennessee	2.44	0.28	0.23	0.65	0.08	0.30	4.0
TX-Texas	9.10	5.36	1.27	5.70	0.55	0.99	23.0
UT-Utah	1.05	2.44	1.09	0.09	0.19	0.03	4.9
VA-Virginia	1.79	0.67	0.35	0.03	0.09	0.11	3.0
VT-Vermont	0.28	0.06	0.01	0.32	0.01	0.01	0.7
WA-Washington	1.86	0.42	0.05	0.16	0.12	0.06	2.7
WI-Wisconsin	2.49	0.67	0.48	0.14	0.32	0.09	4.2
West Virginia	0.78	0.26	0.01	0.28	0.02	0.04	1.4

3.11. Methodology for Estimating CH_4 and N_2O Emissions from Manure Management

The following steps were used to estimate methane (CH_4) and nitrous oxide (N_2O) emissions from the management of livestock manure. Nitrous oxide emissions associated with pasture, range, or paddock systems and daily spread systems are included in the emission estimates for Agricultural Soil Management (see the Agricultural Soils Management Annex).

Step 1: Livestock Population Characterization Data

Annual animal population data for 1990 through 2012 for all livestock types, except American bison, goats, horses, mules and asses were obtained from the USDA National Agricultural Statistics Service (NASS). The population data used in the emissions calculations for cattle, swine, and sheep were downloaded from the USDA NASS Quick Stats Database (USDA 2013a). Poultry population data were obtained from USDA NASS reports (USDA 1995a, 1995b, 1998, 1999, 2004a, 2004b, 2009b, 2009c, 2009d, 2009e, 2010a, 2010b, 2011a, 2011b, 2012a, 2012b, 2013b and 2013c). Goat population data for 1992, 1997, 2002, and 2007 were obtained from the *Census of Agriculture* (USDA 2009a), as were horse, mule and ass population data for 1987, 1992, 1997, 2002, and 2007, and American bison population for 2002 and 2007. American bison population data for 1990-1999 were obtained from the National Bison Association (1999). Additional data sources used and adjustments to these data sets are described below.

Cattle: For all cattle groups (cows, heifers, steers, bulls, and calves), the USDA data provide cattle inventories from January (for each state) and July (as a U.S. total only) of each year. Cattle inventories change over the course of the year, sometimes significantly, as new calves are born and as cattle are moved into feedlots and subsequently slaughtered; therefore, to develop the best estimate for the annual animal population, the populations and the individual characteristics, such as weight and weight gain, pregnancy, and lactation of each animal type were tracked in the Cattle Enteric Fermentation Model (CEFM—see section 6-1 Enteric Fermentation). For animals that have relatively static populations throughout the year, such as mature cows and bulls, the January 1 values were used. For animals that have fluctuating populations throughout the year, such as calves and growing heifers and steer, the populations are modeled based on a transition matrix that uses annual population data from USDA along with USDA data on animal births, placement into feedlots, and slaughter statistics.

Swine: The USDA provides quarterly data for each swine subcategory: breeding, market under 50 pounds (under 23 kg), market 50 to 119 pounds (23 to 54 kg), market 120 to 179 pounds (54 to 81 kg), and market 180 pounds and over (greater than 82 kg). The average of the quarterly data was used in the emission calculations. For states where only December inventory is reported, the December data were used directly.

Sheep: The USDA provides total state-level data annually for lambs and sheep. Population distribution data for lamb and sheep on feed are not available after 1993 (USDA 1994). The number of lamb and sheep on feed for 1994 through 2012 were calculated using the average of the percent of lamb and sheep on feed from 1990 through 1993. In addition, all of the sheep and lamb "on feed" are not necessarily on "feedlots;" they may be on pasture/crop residue supplemented by feed. Data for those animals on feed that are in feedlots versus pasture/crop residue were provided only for lamb in 1993. To calculate the populations of sheep and lamb in feedlots for all years, it was assumed that the percentage of sheep and lamb on feed that are in feedlots versus pasture/crop residue is the same as that for lambs in 1993 (Anderson 2000).

Goats: Annual goat population data by state were available for 1992, 1997, 2002, and 2007 (USDA 2009a). The data for 1992 were used for 1990 through 1992 and the data for 2007 were used for 2007 through 2012. Data for 1993 through 1996, 1998 through 2001, and 2003 through 2006 were extrapolated based on the 1992, 1997, and 2002 Census data.

Horses: Annual horse population data by state were available for 1987, 1992, 1997, 2002, and 2007 (USDA 2009a). Data for 1990 through 1991, 1993 through 1996, 1998 through 2001, 2003 through 2006, and 2008 through 2012 were extrapolated based on the 1987, 1992, 1997, 2002, and 2007 Census data.

Mules and Asses: Annual mule and ass (burro and donkey) population data by state were available for 1987, 1992, 1997, 2002, and 2007 (USDA 2009a). Data for 1990 through 1991, 1993 through 1996, 1998 through 2001, 2003 through 2006, and 2008 through 2012 were extrapolated based on the 1987, 1992, 1997, 2002, and 2007 Census data.

American Bison: Annual American bison population data by state were available for 2002, and 2007 (USDA 2009a). Data for 1990 through 1999 were obtained from the Bison Association (1999). Data for 2000, 2001, 2003 through 2006, and 2008 through 2012 were extrapolated based on the Bison Association and 2002 and 2007 Census data.

Poultry: The USDA provides population data for hens (one year old or older), pullets (hens younger than one year old), other chickens, and production (slaughter) data for broilers and turkeys (USDA 1995a, 1995b, 1998, 1999, 2004a, 2004b, 2009b, 2009c, 2009d, 2009e, 2010a, 2010b, 2011a, 2011b, 2012a, 2012b, 2013b, and 2013c). All poultry population data were adjusted to account for states that report non-disclosed populations to USDA NASS. The combined populations of the states reporting non-disclosed populations are reported as "other" states. State populations for the non-disclosed states were estimated by equally distributing the population attributed to "other" states to each of the non-disclosed states.

Because only production data are available for boilers and turkeys, population data are calculated by dividing the number of animals produced by the number of production cycles per year, or the turnover rate. Based on personal communications with John Lange, an agricultural statistician with USDA NASS, the broiler turnover rate ranges from 3.4 to 5.5 over the course of the inventory. For turkeys, the turnover rate ranges from 2.4 to 3.0. A summary of the livestock population characterization data used to calculate CH_4 and N_2O emissions is presented in Table A- 202.

Step 2: Waste Characteristics Data

Methane and N_2O emissions calculations are based on the following animal characteristics for each relevant livestock population:

- Volatile solids (VS) excretion rate;
- Maximum methane producing capacity (B_o) for U.S. animal waste;
- Nitrogen excretion rate (Nex); and
- Typical animal mass (TAM).

Table A- 203 presents a summary of the waste characteristics used in the emissions estimates. Published sources were reviewed for U.S.-specific livestock waste characterization data that would be consistent with the animal population data discussed in Step 1. The USDA's Agricultural Waste Management Field Handbook (AWMFH; USDA 1996, 2008) is one of the primary sources of waste characteristics. Data from the 1996 and 2008 USDA AWMFH were used to estimate VS and Nex for most animal groups across the time series of the inventory, as shown in Table A- 204 (ERG 2010b and 2010c). The 1996 AWMFH data were based on measured values from U.S. farms; the 2008 AWMFH data were developed using the calculation method created by the American Society of Agricultural and Biological Engineers, which is based on U.S. animal dietary intake and performance measures. Since the values from each of the two AWMFHs result from different estimation methods and reflect changes in animal genetics and nutrition over time, both data sources were used to create a time series across the inventory as neither value would be appropriate to use across the entire span of inventory years. Although the AWMFH values are lower than the IPCC values, these values are more appropriate for U.S. systems because they have been calculated using U.S.-specific data. Animal-specific notes about VS and Nex are presented below:

- Swine: The VS and Nex data for breeding swine are from a combination of the types of animals that make up this animal group, namely gestating and farrowing swine and boars. It is assumed that a group of breeding swine is typically broken out as 80 percent gestating sows, 15 percent farrowing swine, and 5 percent boars (Safley 2000).
- Poultry: Due to the change in USDA reporting of hens and pullets, new nitrogen and VS excretion rates were calculated for the combined population of hens and pullets; a weighted average rate was calculated based on hen and pullet population data from 1990 to 2004.
- Goats, Sheep, Horses, Mules and Asses: In cases where data were not available in the USDA documents, data from the American Society of Agricultural Engineers, Standard D384.1 (ASAE 1998) or the 2006 IPCC Guidelines were used as a supplement.

The method for calculating VS excretion and Nex from American bison, beef and dairy cows, bulls, heifers, and steers is based on the relationship between animal performance characteristics such as diet, lactation, and weight gain and energy utilization. The method used is outlined by the *IPCC 2006 Guidelines* Tier II methodology, and is modeled using the CEFM described in the enteric fermentation portion of the inventory (documented in Moffroid and Pape 2013) in order to take advantage of the detailed diet and animal performance data assembled as part of the Tier II analysis for cattle. For American bison, VS and Nex were assumed to be the same as beef NOF bulls.

The VS content of manure is the fraction of the diet consumed by cattle that is not digested and thus excreted as fecal material; fecal material combined with urinary excretions constitutes manure. The CEFM uses the input of digestible energy (DE) and the energy requirements of cattle to estimate gross energy (GE) intake and enteric CH_4 emissions. GE and DE are used to calculate the indigestible energy per animal as gross energy minus digestible energy plus the amount of gross energy for urinary energy excretion per animal (2 or 4 percent). This value is then converted to VS production per animal using the typical conversion of dietary gross energy to dry organic matter of 18.45 MJ/kg, after subtracting out the ash content of manure. The current equation recommended by the *2006 IPCC Guidelines* is:

$$\text{VS production (kg)} = \left[(\text{GE - DE}) + (\text{UE} \times \text{GE})\right] \times \frac{1 - ASH}{18.45}$$

where,

GE = Gross energy intake (MJ)
DE = Digestible energy (MJ)
(UE × GE) = Urinary energy expressed as fraction of GE, assumed to be 0.04 except for feedlots which are reduced 0.02 as a result of the high grain content of their diet.
ASH = Ash content of manure calculated as a fraction of the dry matter feed intake (assumed to be 0.08).
18.45 = Conversion factor for dietary GE per kg of dry matter (MJ per kg). This value is relatively constant across a wide range of forage and grain-based feeds commonly consumed by livestock.

Total nitrogen ingestion in cattle is determined by dietary protein intake. When feed intake of protein exceeds the nutrient requirements of the animal, the excess nitrogen is excreted, primarily through the urine. To calculate the nitrogen excreted by each animal type, the CEFM utilizes the energy balance calculations recommended by the IPCC (2006) for gross energy and the energy required for growth along with inputs of weight gain, milk production, and the percent of crude protein in the diets. The total nitrogen excreted is measured in the CEFM as nitrogen consumed minus nitrogen retained by the animal for growth and in milk. The basic equation for calculating Nex is shown below, followed by the equations for each of the constituent parts.

$$\text{N}_{\text{excreted}} = \text{N}_{\text{consumed}} - \left(\text{N}_{\text{growth}} + \text{N}_{\text{milk}}\right)$$

where,

$\text{N}_{\text{excreted}}$ = Daily N excreted per animal, kg per animal per day.
$\text{N}_{\text{consumed}}$ = Daily N intake per animal, kg per animal per day
N_{growth} = Nitrogen retained by the animal for growth, kg per animal per day
N_{milk} = Nitrogen retained in milk, kg per animal per day

The equation for N consumed is based on the *2006 IPCC Guidelines*, and is estimated as:

$$N_{consumed} = \left[\frac{GE}{18.45} * \left(\frac{\frac{CP\%}{100}}{6.25}\right)\right]$$

where,

$\text{N}_{\text{consumed}}$ = Daily N intake per animal, kg per animal per day
GE = Gross energy intake, as calculated in the CEFM, MJ per animal per day
18.45 = Conversion factor for dietary GE per kg of dry matter, MJ per kg.
CP% = Percent crude protein in diet, input into the CEFM
6.25 = Conversion from kg of dietary protein to kg of dietary N, kg feed per kg N

The portion of consumed N that is retained as product equals the nitrogen required for weight gain plus that in milk. The nitrogen retained in body weight gain by stockers, replacements, or feedlot animals is calculated using the net energy for growth (NEg), weight gain (WG), and other conversion factors and constants. The equation matches current *2006 IPCC Guidelines* recommendations, and is as follows:

$$N_{growth} = \frac{\dfrac{\left\{WG * \left[268 - \dfrac{(7.03 * NEg)}{WG}\right]\right\}}{1000}}{6.25}$$

where,

N $_{growth}$ = Nitrogen retained by the animal for growth, kg per animal per day
WG = Daily weight gain of the animal, as input into the CEFM transition matrix, kg per day
268 = Constant from *2006 IPCC Guidelines*
7.03 = Constant from *2006 IPCC Guidelines*
NEg = Net energy required for growth, as calculated in the CEFM, MJ per animal per day
1,000 = Conversion from grams to kilograms
6.25 = Conversion from kg of dietary protein to kg of dietary N, kg feed per kg N

The N content of milk produced also currently matches the *2006 IPCC Guidelines*, and is calculated using milk production and percent protein, along with conversion factors. Milk N retained as product is calculated using the following equation:

$$N_{milk} = \frac{milk * \left(\dfrac{pr\%}{100}\right)}{6.38}$$

where,

N $_{milk}$ = Nitrogen retained in milk, kg per animal per day
milk = Milk production, kg per day
pr% = Percent protein in milk, estimated from the fat content as 1.9 + 0.4 * %Fat (Fat assumed to be 4%)
100 = Conversion from percent to value (e.g., 4% to 0.04)
6.38 = Conversion from kg Protein to kg N

The VS and N equations above were used to calculate VS and Nex rates for each state, animal type (heifers and steer on feed, heifers and steer not on feed, bulls and American bison), and year. Table A- 205 presents the state-specific VS and Nex production rates used for cattle in 2012.

Step 3: Waste Management System Usage Data

Table A- 206 summarizes 2012 manure distribution data among waste management systems (WMS) at beef feedlots, dairies, dairy heifer facilities, and swine, layer, broiler, and turkey operations. Manure from the remaining animal types (beef cattle not on feed, American bison, goats, horses, mules and asses and sheep) is managed on pasture, range, or paddocks, on drylot, or with solids storage systems. Additional information on the development of the manure distribution estimates for each animal type is presented below. Definitions of each WMS type are presented in Table A-207.

Beef Cattle, Dairy Heifers and American Bison: The beef feedlot and dairy heifer WMS data were developed using information from EPA's Office of Water's engineering cost analyses conducted to support the development of effluent limitations guidelines for Concentrated Animal Feeding Operations (EPA 2002b). Based on EPA site visits and state contacts supporting this work and additional personal communication with the national USDA office to estimate the percent of beef steers and heifers in feedlots (Milton 2000), feedlot manure is almost exclusively managed in drylots. Therefore, for these animal groups, the percent of manure deposited in drylots is assumed to be 100 percent. In addition, there is a small amount of manure contained in runoff, which may or may not be collected in runoff ponds. Using the expert opinions and EPA and USDA data, the runoff from feedlots was calculated by region in *Calculations: Percent Distribution of Manure for Waste Management Systems* (ERG 2000a) and was used to estimate the percentage of manure managed in runoff ponds in addition to drylots; this percentage ranges from 0.4 to 1.3 percent. The percentage of manure generating emissions from beef feedlots is therefore greater than 100 percent. The remaining population categories of beef cattle outside of feedlots are managed through pasture, range, or paddock systems, which are utilized for the majority of the population of beef cattle in the country. American bison WMS data were assumed to be the same as beef cattle not on feed.

Dairy Cows: The WMS data for dairy cows were developed using data from the Census of Agriculture, EPA's Office of Water, USDA, and expert sources. Farm-size distribution data are reported in the 1992, 1997, 2002, and 2007 Census of Agriculture (USDA 2009a). It was assumed that the Census data provided for 1992 were the same as that for 1990 and 1991, and data provided for 2007 were the same as that for 2008 through 2012. Data for 1993 through 1996, 1998 through 2001, and 2003 through 2006 were extrapolated using the 1992, 1997, 2002, and 2007 data. The percent of waste by system was estimated using the USDA data broken out by geographic region and farm size.

Based on EPA site visits and the expert opinion of state contacts, manure from dairy cows at medium (200 through 700 head) and large (greater than 700 head) operations are managed using either flush systems or scrape/slurry systems. In addition, they may have a solids separator in place prior to their storage component. Estimates of the percent of farms that use each type of system (by geographic region) were developed by EPA's Office of Water, and were used to estimate the percent of waste managed in lagoons (flush systems), liquid/slurry systems (scrape systems), and solid storage (separated solids) (EPA 2002b).

Manure management system data for small (fewer than 200 head) dairies were obtained from USDA's Animal and Plant Health Inspection Service (APHIS)'s National Animal Health Monitoring System (Ott 2000). These data are based on a statistical sample of farms in the 20 U.S. states with the most dairy cows. Small operations are more likely to use liquid/slurry and solid storage management systems than anaerobic lagoon systems. The reported manure management systems were deep pit, liquid/slurry (includes slurry tank, slurry earth-basin, and aerated lagoon), anaerobic lagoon, and solid storage (includes manure pack, outside storage, and inside storage).

Data regarding the use of daily spread and pasture, range, or paddock systems for dairy cattle were obtained from personal communications with personnel from several organizations. These organizations include state NRCS offices, state extension services, state universities, USDA NASS, and other experts (Deal 2000, Johnson 2000, Miller 2000, Stettler 2000, Sweeten 2000, and Wright 2000). Contacts at Cornell University provided survey data on dairy manure management practices in New York (Poe et al. 1999). Census of Agriculture population data for 1992, 1997, 2002, and 2007 (USDA 2009a) were used in conjunction with the state data obtained from personal communications to determine regional percentages of total dairy cattle and dairy waste that are managed using these systems. These percentages were applied to the total annual dairy cow and heifer state population data for 1990 through 2012, which were obtained from the USDA NASS (USDA 2013a).

Of the dairies using systems other than daily spread and pasture, range, or paddock systems, some dairies reported using more than one type of manure management system. Due to limitations in how USDA APHIS collects the manure management data, the total percent of systems for a region and farm size is greater than 100 percent. However, manure is typically partitioned to use only one manure management system, rather than transferred between several different systems. Emissions estimates are only calculated for the final manure management system used for each portion of manure. To avoid double counting emissions, the reported percentages of systems in use were adjusted to equal a total of 100 percent using the same distribution of systems. For example, if USDA reported that 65 percent of dairies use deep pits to manage manure and 55 percent of dairies use anaerobic lagoons to manage manure, it was assumed that 54 percent (i.e., 65 percent divided by 120 percent) of the manure is managed with deep pits and 46 percent (i.e., 55 percent divided by 120 percent) of the manure is managed with anaerobic lagoons (ERG 2000a).

Finally, the percentage of manure managed with anaerobic digestion (AD) systems with methane capture and combustion was added to the WMS distributions. AD system data were obtained from EPA's AgSTAR Program's project database (EPA 2012). This database includes basic information for AD systems in the U.S., based on publically available data and data submitted by farm operators, project developers, financiers, and others involved in the development of farm AD projects.

Swine: The distribution of manure managed in each WMS was estimated using data from a USDA APHIS report and EPA's Office of Water site visits (Bush 1998, ERG 2000a). The USDA APHIS data are based on a statistical sample of farms in the 16 U.S. states with the most hogs. For operations with less than 200 head, manure management system data were obtained from USDA APHIS (Bush 1998), it was assumed that those operations use pasture, range, or paddock systems. For swine operations with greater than 200 head, the percent of waste managed in each system was estimated using the EPA and USDA data broken out by geographic region and farm size. Farm-size distribution data reported in the 1992, 1997, 2002, and 2007 Census of Agriculture (USDA 2009a) were used to determine the percentage of all swine utilizing the various manure management systems. It was assumed that the swine farm size data provided for 1992 were the same as that for 1990 and 1991, and data provided for 2007 were the same as that for 2008 through 2012. Data for 1993 through 1996, 1998 through 2001, and 2003 through 2006 were extrapolated using the 1992, 1997, 2002, and 2007 data. The manure management systems reported in the census were deep pit, liquid/slurry (includes above- and below-ground slurry), anaerobic lagoon, and solid storage (includes solids separated from liquids).

Some swine operations reported using more than one management system; therefore, the total percent of systems reported by USDA for a region and farm size was greater than 100 percent. Typically, this means that a portion of the manure at a swine operation is handled in one system (e.g., liquid system), and a separate portion of the manure is handled in another system (e.g., dry system). However, it is unlikely that the same manure is moved from one system to another, which could result in increased emissions, so reported systems data were normalized to 100 percent for incorporation into the WMS distribution, using the same method as described above for dairy operations. As with dairy, AD WMS were added to the WMS distribution based on data from EPA's AgSTAR database (EPA 2012).

Sheep: WMS data for sheep were obtained from USDA NASS sheep report for years 1990 through 1993 (USDA 1994). Data for 2001 are obtained from USDA APHIS's national sheep report (USDA, APHIS 2003). The USDA APHIS data are based on a statistical sampled of farms in the 22 U.S. states with the most sheep. The data for years 1994-2000 are calculated assuming a linear progression from 1993 to 2001. Due to lack of additional data, data for years 2002 and beyond are assumed to be the same as 2001. Based on expert opinion, it was assumed that all sheep manure not deposited in feedlots was deposited on pasture, range, or paddock lands (Anderson 2000).

Goats, Horses, and Mules and Asses: WMS data for 1990 to 2012 were obtained from Appendix H of *Global Methane Emissions from Livestock and Poultry Manure* (EPA 1992). This report presents state WMS usage in percentages for the major animal types in the U.S., based on information obtained from extension service personnel in each state. It was assumed that all manure not deposited in pasture, range, or paddock lands was managed in dry systems. For mules and asses, the WMS was assumed to be the same as horses.

Poultry—Hens (one year old or older), Pullets (hens less than one year old), and Other Chickens: WMS data for 1992 were obtained from *Global Methane Emissions from Livestock and Poultry Manure* (EPA 1992). These data were also used to represent 1990 and 1991. The percentage of layer operations using a shallow pit flush house with anaerobic lagoon or high-rise house without bedding was obtained for 1999 from a United Egg Producers voluntary survey (UEP 1999). These data were augmented for key poultry states (AL, AR, CA, FL, GA, IA, IN, MN, MO, NC, NE, OH, PA, TX, and WA) with USDA data (USDA, APHIS 2000). It was assumed that the change in system usage between 1990 and 1999 is proportionally distributed among those years of the inventory. It was also assumed that system usage in 2000 through 2012 was equal to that estimated for 1999. Data collected for EPA's Office of Water, including information collected during site visits (EPA 2002b), were used to estimate the distribution of waste by management system and animal type. As with dairy and swine, using information about AD WMS from EPA's AgSTAR database (EPA 2012), AD was added to the WMS distribution for poultry operations.

Poultry—Broilers and Turkeys: The percentage of turkeys and broilers on pasture was obtained from the Office of Air and Radiation's *Global Methane Emissions from Livestock and Poultry Manure* (EPA 1992). It was assumed that one percent of poultry waste is deposited in pastures, ranges, and paddocks (EPA 1992). The remainder of waste is assumed to be deposited in operations with bedding management. As with dairy, swine, and other poultry, AD systems were added to the WMS distributions based on information from EPA's AgSTAR database (EPA 2012).

Step 4: Emission Factor Calculations

Methane conversion factors (MCFs) and N_2O emission factors (EFs) used in the emission calculations were determined using the methodologies presented below.

Methane Conversion Factors (MCFs)

Climate-based IPCC default MCFs (IPCC 2006) were used for all dry systems; these factors are presented in Table A- 208. A U.S.-specific methodology was used to develop MCFs for all lagoon and liquid systems.

For animal waste managed in dry systems, the appropriate IPCC default MCF was applied based on annual average temperature data. The average county and state temperature data were obtained from the National Climate Data Center (NOAA 2012) and each state and year in the inventory was assigned a climate classification of cool, temperate or warm. Although there are some specific locations in the U.S. that may be included in the warm climate category, no aggregated state-level annual average temperatures are included in this category. In addition, some counties in a particular state may be included in the cool climate category, although the aggregated state-level annual average temperature may be included in the temperate category. Although considering the temperatures at a state level instead of a county level may be causing some specific locations to be classified into an inappropriate climate category, using the state level annual average temperature provides an estimate that is appropriate for calculating the national average.

For anaerobic lagoons and other liquid systems a climate-based approach based on the van't Hoff-Arrhenius equation was developed to estimate MCFs that reflects the seasonal changes in temperatures, and also accounts for long-term retention time. This approach is consistent with the recently revised guidelines from IPCC (IPCC 2006). The van't Hoff-Arrhenius equation, with a base temperature of 30°C, is shown in the following equation (Safley and Westerman 1990):

$$f = \exp\left[\frac{E(T_2 - T_1)}{RT_1T_2}\right]$$

where,

f = van't Hoff-Arrhenius f factor, the proportion of VS that are biologically available for conversion to CH_4 based on the temperature of the system
T_1 = 303.15K
T_2 = Ambient temperature (K) for climate zone (in this case, a weighted value for each state)
E = Activation energy constant (15,175 cal/mol)
R = Ideal gas constant (1.987 cal/K mol)

For those animal populations using liquid manure management systems or manure runoff ponds (i.e., dairy cow, dairy heifer, layers, beef in feedlots, and swine) monthly average state temperatures were based on the counties where the specific animal population resides (i.e., the temperatures were weighted based on the percent of animals located in each county). County population data were calculated from state-level population data from NASS and county-state distribution data from the 1992, 1997, 2002, and 2007 Census data (USDA 2009a). County population distribution data for 1990 and 1991 were assumed to be the same as 1992; county population distribution data for 1993 through 1996 were extrapolated based on 1992 and 1997 data; county population data for 1998 through 2001 were extrapolated based on 1997 and 2002 data; county population data for 2003 through 2006 were extrapolated based on 2002 and 2007 data; and county population data for 2008 to 2012 were assumed to be the same as 2007.

Annual MCFs for liquid systems are calculated as follows for each animal type, state, and year of the inventory:

- The weighted-average temperature for a state is calculated using the county population estimates and average monthly temperature in each county. Monthly temperatures are used to calculate a monthly van't Hoff-Arrhenius f factor, using the equation presented above. A minimum temperature of 5°C is used for uncovered anaerobic lagoons and 7.5°C is used for liquid/slurry and deep pit systems.

- Monthly production of VS added to the system is estimated based on the animal type, number of animals present, and the volatile solids excretion rate of the animals.

- For lagoon systems, the calculation of methane includes a management and design practices (MDP) factor. This factor, equal to 0.8, was developed based on model comparisons to empirical CH_4 measurement data from anaerobic lagoon systems in the United States (ERG 2001). The MDP factor represents management and design factors which cause a system to operate at a less than optimal level.

- For all systems other than anaerobic lagoons, the amount of VS available for conversion to CH_4 each month is assumed to be equal to the amount of VS produced during the month (from Step 3). For anaerobic lagoons, the amount of VS available also includes VS that may remain in the system from previous months.

- The amount of VS consumed during the month is equal to the amount available for conversion multiplied by the *f* factor.
- For anaerobic lagoons, the amount of VS carried over from one month to the next is equal to the amount available for conversion minus the amount consumed. Lagoons are also modeled to have a solids clean-out once per year, occurring in the month of October.
- The estimated amount of CH_4 generated during the month is equal to the monthly VS consumed multiplied by the maximum CH_4 potential of the waste (B_o).

The annual MCF is then calculated as:

$$MCF_{annual} = \frac{CH_4 \text{ generated }_{annual}}{VS \text{ produced }_{annual} \times B_o}$$

where,

MCF_{annual} = Methane conversion factor
VS produced $_{annual}$ = Volatile solids excreted annually
B_o = Maximum CH_4 producing potential of the waste

In order to account for the carry-over of VS from one year to the next, it is assumed that a portion of the VS from the previous year are available in the lagoon system in the next year. For example, the VS from October, November, and December of 2005 are available in the lagoon system starting January of 2006 in the MCF calculation for lagoons in 2006. Following this procedure, the resulting MCF for lagoons accounts for temperature variation throughout the year, residual VS in a system (carry-over), and management and design practices that may reduce the VS available for conversion to CH_4. It is assumed that liquid-slurry systems have a retention time less than 30 days, so the liquid-slurry MCF calculation doesn't reflect the VS carry-over.

The liquid system MCFs are presented in Table A- 209 by state, WMS, and animal group for 2012.

Nitrous Oxide Emission Factors

Direct N_2O EFs for manure management systems (kg N_2O-N/kg excreted N) were set equal to the most recent default IPCC factors (IPCC 2006), presented in Table A- 210.

Indirect N_2O EFs account for two fractions of nitrogen losses: volatilization of ammonia (NH_3) and NO_X ($Frac_{gas}$) and runoff/leaching ($Frac_{runoff/leach}$). IPCC default indirect N_2O EFs were used to estimate indirect N_2O emissions. These factors are 0.010 kg N_2O-N/kg N for volatilization and 0.0075 kg N_2O/kg N for runoff/leaching.

Country-specific estimates of N losses were developed for $Frac_{gas}$ and $Frac_{runoff/leach}$ for the United States. The vast majority of volatilization losses are NH_3. Although there are also some small losses of NO_X, no quantified estimates were available for use and those losses are believed to be small (about 1 percent) in comparison to the NH_3 losses. Therefore, $Frac_{gas}$ values were based on WMS-specific volatilization values estimated from U.S. EPA's *National Emission Inventory - Ammonia Emissions from Animal Agriculture Operations* (EPA 2005). To estimate $Frac_{runoff/leach}$, data from EPA's Office of Water were used that estimate the amount of runoff from beef, dairy, and heifer operations in five geographic regions of the country (EPA 2002b). These estimates were used to develop U.S. runoff factors by animal type, WMS, and region. Nitrogen losses from leaching are believed to be small in comparison to the runoff losses and there are a lack of data to quantify these losses. Therefore, leaching losses were assumed to be zero and $Frac_{runoff/leach}$ was set equal to the runoff loss factor. Nitrogen losses from volatilization and runoff/leaching are presented in Table A- 211.

Step 5: CH_4 Emission Calculations

To calculate CH_4 emissions for animals other than cattle, first the amount of VS excreted in manure that is managed in each WMS was estimated:

$$\text{VS excreted}_{\text{State, Animal, WMS}} = \text{Population}_{\text{State, Animal}} \times \frac{\text{TAM}}{1000} \times \text{VS} \times \text{WMS} \times 365.25$$

where,

VS excreted $_{\text{State, Animal, WMS}}$ = Amount of VS excreted in manure managed in each WMS for each animal type (kg/yr)
Population $_{\text{State, Animal}}$ = Annual average state animal population by animal type (head)
TAM = Typical animal mass (kg)
VS = Volatile solids production rate (kg VS/1000 kg animal mass/day)
WMS = Distribution of manure by WMS for each animal type in a state (percent)
365.25 = Days per year

Using the CEFM VS data for cattle, the amount of VS excreted in manure that is managed in each WMS was estimated using the following equation:

$$\text{VS excreted}_{\text{State,Animal,WMS}} = \text{Population}_{\text{State,Animal}} \times \text{VS} \times \text{WMS}$$

where,

VS excreted $_{\text{State, Animal, WMS}}$ = Amount of VS excreted in manure managed in each WMS for each animal type (kg/yr)
Population $_{\text{State, Animal}}$ = Annual average state animal population by animal type (head)
VS = Volatile solids production rate (kg VS/animal/year)
WMS = Distribution of manure by WMS for each animal type in a state (percent)

For all animals, the estimated amount of VS excreted into a WMS was used to calculate CH_4 emissions using the following equation:

$$CH_4 = \sum_{\text{State, Animal, WMS}} \left(\text{VS excreted}_{\text{State, Animal, WMS}} \times B_o \times \text{MCF} \times 0.662 \right)$$

where,

CH_4 = CH_4 emissions (kg CH_4/yr)
VS excreted $_{\text{WMS, State}}$ = Amount of VS excreted in manure managed in each WMS (kg/yr)
B_o = Maximum CH_4 producing capacity (m^3 CH_4/kg VS)
MCF $_{\text{animal, state, WMS}}$ = MCF for the animal group, state and WMS (percent)
0.662 = Density of methane at 25° C (kg CH_4/m^3 CH_4)

A calculation was developed to estimate the amount of CH_4 emitted from AD systems utilizing CH_4 capture and combustion technology. First, AD systems were assumed to produce 90 percent of the maximum CH_4 producing capacity. This value is applied for all climate regions and AD system types. However, the actual amount of CH_4 produced by each AD system is very variable and will change based on operational and climate conditions and an assumption of 90 percent is likely overestimating CH_4 production from some systems and underestimating CH_4 production in other systems. The CH_4 production of AD systems is calculated using the equation below:

$$CH_4 \text{ Production AD}_{\text{AD System}} = \text{Population AD}_{\text{AD System}} \times \frac{\text{TAM}}{1000} \times \text{VS} \times B_o \times 0.662 \times 365.25 \times 0.90$$

where,

CH_4 Production AD$_{\text{AD system}}$ = CH_4 production from a particular AD system, (kg/yr)
Population AD $_{\text{state}}$ = Number of animals on a particular AD system
VS = Volatile solids production rate (kg VS/1000 kg animal mass-day)
TAM = Typical Animal Mass (kg/head)
B_o = Maximum CH_4 producing capacity (CH4 m^3/kg VS)
0.662 = Density of CH_4 at 25° C (kg CH_4/m^3 CH_4)
365.25 = Days/year
0.90 = CH_4 production factor for AD systems

The total amount of CH_4 produced by AD is calculated only as a means to estimate the emissions from AD; i.e., only the estimated amount of CH_4 actually entering the atmosphere from AD is reported in the inventory. The emissions to the atmosphere from AD are a result of leakage and incomplete combustion and are calculated using the collection efficiency (CE) and destruction efficiency (DE) of the AD system. The three primary types of AD systems in the U.S. are covered lagoons, complete mix and plug flow systems. The CE of covered lagoon systems was assumed to be 75 percent, and the CE of complete mix and plug flow AD systems was assumed to be 99 percent (EPA 2008). The CH_4 DE from flaring or burning in an engine was assumed to be 98 percent; therefore, the amount of CH_4 that would not be flared or combusted was assumed to be 2 percent (EPA 2008). The amount of CH_4 produced by systems with AD was calculated with the following equation:

$$\text{CH}_4\ \text{Emissions AD} = \sum_{\text{State, Animal, AD Systems}} \left(\begin{array}{l} \left[\text{CH}_4\ \text{Production AD}_{\text{AD system}} \times \text{CE}_{\text{AD system}} \times (1 - \text{DE})\right] \\ + \left[\text{CH}_4\ \text{Production AD}_{\text{AD system}} \times \left(1 - \text{CE}_{\text{AD system}}\right)\right] \end{array} \right)$$

where,

CH_4 Emissions AD = CH_4 emissions from AD systems, (kg/yr)
CH_4 Production $AD_{\text{AD system}}$ = CH_4 production from a particular AD system, (kg/yr)
$CE_{\text{AD system}}$ = Collection efficiency of the AD system, varies by AD system type
DE = Destruction efficiency of the AD system, 0.98 for all systems

Step 6: N_2O Emission Calculations

In addition to CH_4 emissions, total N_2O emissions were also estimated from manure management systems. Total N_2O emissions were calculated by summing direct and indirect N_2O emissions. The first step in estimating direct and indirect N_2O emissions was calculating the amount of N excreted in manure and managed in each WMS. For calves and animals other than cattle the following equation was used:

$$\text{N excreted}_{\text{State, Animal, WMS}} = \text{Population}_{\text{State, Animal}} \times \text{WMS} \times \frac{\text{TAM}}{1000} \times \text{Nex} \times 365.25$$

where,

N excreted $_{\text{State, Animal, WMS}}$ = Amount of N excreted in manure managed in each WMS for each animal type (kg/yr)
Population $_{\text{state}}$ = Annual average state animal population by animal type (head)
WMS = Distribution of manure by waste management system for each animal type in a state (percent)
TAM = Typical animal mass (kg)
Nex = Total Kjeldahl nitrogen excretion rate (kg N/1000 kg animal mass/day)
365.25 = Days per year

Using the CEFM Nex data for cattle other than calves, the amount of N excreted was calculated using the following equation:

$$\text{N excreted}_{\text{State, Animal, WMS}} = \text{Population}_{\text{State, Animal}} \times \text{WMS} \times \text{Nex}$$

where,

N excreted $_{\text{State, Animal, WMS}}$ = Amount of N excreted in manure managed in each WMS for each animal type (kg/yr)
Population $_{\text{state}}$ = Annual average state animal population by animal type (head)

WMS = Distribution of manure by waste management system for each animal type in a state (percent)
Nex = Total Kjeldahl N excretion rate (kg N/animal/year)

For all animals, direct N_2O emissions were calculated as follows:

$$\text{Direct } N_2O = \sum_{\text{State, Animal, WMS}} \left(\text{N excreted}_{\text{State, Animal, WMS}} \times EF_{WMS} \times \frac{44}{28} \right)$$

where,

Direct N_2O = Direct N_2O emissions (kg N_2O/yr)
N excreted $_{\text{State, Animal, WMS}}$ = Amount of N excreted in manure managed in each WMS for each animal type (kg/yr)
EF_{WMS} = Direct N_2O emission factor from IPCC guidelines (kg N_2O-N /kg N)
44/28 = Conversion factor of N_2O-N to N_2O

Indirect N_2O emissions were calculated for all animals with the following equation:

$$\text{Indirect } N_2O = \sum_{\text{State, Animal, WMS}} \left(\left[\text{N excreted}_{\text{State, Animal, WMS}} \times \frac{\text{Frac}_{\text{gas, WMS}}}{100} \times EF_{\text{volatilization}} \times \frac{44}{28} \right] + \left[\text{N excreted}_{\text{State, Animal, WMS}} \times \frac{\text{Frac}_{\text{runoff/leach, WMS}}}{100} \times EF_{\text{runnoff/leach}} \times \frac{44}{28} \right] \right)$$

where,

Indirect N_2O = Indirect N_2O emissions (kg N_2O/yr)
N excreted $_{\text{State, Animal, WMS}}$ = Amount of N excreted in manure managed in each WMS for each animal type (kg/yr)
$\text{Frac}_{\text{gas,WMS}}$ = Nitrogen lost through volatilization in each WMS
$\text{Frac}_{\text{runoff/leach,WMS}}$ = Nitrogen lost through runoff and leaching in each WMS (data were not available for leaching so the value reflects only runoff)
$EF_{\text{volatilization}}$ = Emission factor for volatilization (0.010 kg N_2O-N/kg N)
$EF_{\text{runoff/leach}}$ = Emission factor for runoff/leaching (0.0075 kg N_2O-N/kg N)
44/28 = Conversion factor of N_2O-N to N_2O

Emission estimates of CH_4 and N_2O by animal type are presented for all years of the inventory in Table A- 212 and Table A- 213 respectively. Emission estimates for 2012 are presented by animal type and state in Table A- 214 and Table A- 215 respectively.

Table A- 202: Livestock Population (1,000 Head)

Animal Type	1990	1995	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Dairy Cattle	14,144	13,590	13,217	13,165	13,215	13,021	13,165	13,398	13,487	13,658	13,761	13,612	13,722	13,816
Dairy Cows	10,015	9,482	9,172	9,106	9,142	8,988	9,004	9,104	9,145	9,257	9,333	9,086	9,150	9,230
Dairy Heifer	4,129	4,108	4,045	4,060	4,073	4,033	4,162	4,294	4,343	4,401	4,429	4,526	4,572	4,586
Swine[a]	53,941	58,899	58,913	60,028	59,827	60,735	61,073	61,887	65,417	67,408	65,990	64,768	65,589	66,516
Market <50 lb.	18,359	19,656	19,659	19,863	19,929	20,222	20,228	20,514	21,812	19,964	19,444	19,124	19,385	19,580
Market 50-119 lb.	11,734	12,836	12,900	13,284	13,138	13,400	13,519	13,727	14,557	17,219	16,995	16,699	16,966	17,257
Market 120-179 lb.	9,440	10,545	10,708	11,013	11,050	11,227	11,336	11,443	12,185	12,931	12,567	12,313	12,438	12,660
Market >180 lb.	7,510	8,937	9,465	9,738	9,701	9,922	9,997	10,113	10,673	11,193	11,079	10,854	11,009	11,181
Breeding	6,899	6,926	6,181	6,129	6,011	5,963	5,993	6,090	6,190	6,102	5,905	5,778	5,791	5,837
Beef Cattle[b]	87,228	95,683	89,118	89,102	88,232	86,441	86,954	88,070	87,639	86,450	85,812	85,183	83,705	81,443
Feedlot Steers	6,357	7,233	7,932	8,116	8,416	8,018	8,116	8,724	8,674	8,481	8,446	8,563	8,743	8,515
Feedlot Heifers	3,192	3,831	4,569	4,557	4,676	4,521	4,536	4,801	4,730	4,589	4,508	4,628	4,803	4,695
NOF Bulls	2,160	2,385	2,274	2,244	2,248	2,201	2,214	2,258	2,214	2,207	2,184	2,190	2,155	2,096
NOF Calves	22,561	23,499	22,389	22,325	21,997	21,781	21,678	21,621	21,483	21,155	21,001	20,861	20,648	20,094
NOF Heifers	10,182	11,829	9,832	9,843	9,564	9,321	9,550	9,716	9,592	9,350	9,448	9,348	8,878	8,677
NOF Steers	10,321	11,716	8,724	8,883	8,347	8,067	8,185	8,248	8,302	8,233	8,515	8,223	7,628	7,209
NOF Cows	32,455	35,190	33,398	33,134	32,983	32,531	32,674	32,703	32,644	32,435	31,712	31,371	30,850	30,158
Sheep	11,358	8,989	6,908	6,623	6,321	6,065	6,135	6,200	6,120	5,950	5,747	5,620	5,480	5,365
Sheep On Feed	1,180	1,771	3,256	3,143	3,049	2,923	2,971	3,026	3,000	2,911	2,806	2,778	2,692	2,661
Sheep NOF	10,178	7,218	3,652	3,480	3,272	3,142	3,164	3,174	3,120	3,039	2,941	2,842	2,788	2,704
Goats	2,516	2,357	2,475	2,530	2,652	2,774	2,897	3,019	3,141	3,141	3,141	3,141	3,141	3,141
Poultry[c]	1,537,074	1,826,977	2,060,398	2,097,691	2,085,268	2,130,877	2,150,410	2,154,236	2,166,936	2,175,990	2,088,828	2,104,335	2,095,951	2,074,269
Hens >1 yr.	273,467	299,071	340,317	340,209	340,979	343,922	348,203	349,888	346,613	339,859	341,005	341,884	338,944	345,730
Pullets	73,167	81,369	95,656	95,289	100,346	101,429	96,809	96,596	103,816	99,458	102,301	105,738	102,233	103,058
Chickens	6,545	7,637	8,126	8,353	8,439	8,248	8,289	7,938	8,164	7,589	8,487	7,390	6,922	6,817
Broilers	1,066,209	1,331,940	1,525,413	1,562,015	1,544,155	1,589,209	1,613,091	1,612,327	1,619,400	1,638,055	1,554,582	1,567,927	1,565,018	1,534,164
Turkeys	117,685	106,960	90,887	91,826	91,349	88,069	84,018	87,487	88,943	91,029	82,453	81,396	82,833	84,500
Horses	2,212	2,632	3,519	3,644	3,721	3,798	3,875	3,952	4,029	4,106	4,183	4,260	4,336	4,413
Mules and Asses	63	101	109	105	141	177	212	248	284	319	355	391	427	462
American Bison	47	104	213	232	225	218	212	205	198	192	185	179	173	167

Note: Totals may not sum due to independent rounding.

[a] Prior to 2008, the Market <50 lbs category was <60 lbs and the Market 50-119 lbs category was Market 60-119 lbs; USDA updated the categories to be more consistent with international animal categories.

[b] NOF = Not on Feed

[c] Pullets includes laying pullets, pullets younger than 3 months, and pullets older than 3 months.

Table A- 203: Waste Characteristics Data

	Typical Animal Mass, TAM		Total Kjeldahl Nitrogen Excreted, Nex[a]		Maximum Methane Generation Potential, B_0		Volatile Solids Excreted, VS[a]	
Animal Group	Value (kg)	Source	Value	Source	Value (m^3 CH_4/kg VS added)	Source	Value	Source
Dairy Cows	680	CEFM	Table A- 94	CEFM	0.24	Morris 1976	Table A- 94	CEFM
Dairy Heifers	406-408	CEFM	Table A- 94	CEFM	0.17	Bryant et al. 1976	Table A- 94	CEFM
Feedlot Steers	419-457	CEFM	Table A- 94	CEFM	0.33	Hashimoto 1981	Table A- 94	CEFM
Feedlot Heifers	384-430	CEFM	Table A- 94	CEFM	0.33	Hashimoto 1981	Table A- 94	CEFM
NOF Bulls	831-917	CEFM	Table A- 94	CEFM	0.17	Hashimoto 1981	Table A- 94	CEFM
NOF Calves	118	ERG 2003b	Table A- 205	USDA 1996, 2008	0.17	Hashimoto 1981	Table A- 205	USDA 1996, 2008
NOF Heifers	296-407	CEFM	Table A- 199	CEFM	0.17	Hashimoto 1981	Table A- 199	CEFM
NOF Steers	314-335	CEFM	Table A- 94	CEFM	0.17	Hashimoto 1981	Table A- 94	CEFM
NOF Cows	554-611	CEFM	Table A- 94	CEFM	0.17	Hashimoto 1981	Table A- 94	CEFM
American Bison	578.5	Meagher 1986	Table A- 199	CEFM	0.17	Hashimoto 1981	Table A- 199	CEFM
Market Swine <50 lbs.	13	ERG 2010a	Table A- 205	USDA 1996, 2008	0.48	Hashimoto 1984	Table A- 205	USDA 1996, 2008
Market Swine <60 lbs.	16	Safley 2000	Table A- 205	USDA 1996, 2008	0.48	Hashimoto 1984	Table A- 205	USDA 1996, 2008
Market Swine 50-119 lbs.	39	ERG 2010a	Table A- 205	USDA 1996, 2008	0.48	Hashimoto 1984	Table A- 205	USDA 1996, 2008
Market Swine 60-119 lbs.	41	Safley 2000	Table A- 205	USDA 1996, 2008	0.48	Hashimoto 1984	Table A- 205	USDA 1996, 2008
Market Swine 120-179 lbs.	68	Safley 2000	Table A- 205	USDA 1996, 2008	0.48	Hashimoto 1984	Table A- 205	USDA 1996, 2008
Market Swine >180 lbs.	91	Safley 2000	Table A- 205	USDA 1996, 2008	0.48	Hashimoto 1984	Table A- 205	USDA 1996, 2008
Breeding Swine	198	Safley 2000	Table A- 205	USDA 1996, 2008	0.48	Hashimoto 1984	Table A- 205	USDA 1996, 2008
Feedlot Sheep	25	EPA 1992	Table A- 205	ASAE 1998, USDA 2008	0.36	EPA 1992	Table A- 205	ASAE 1998, USDA 2008
NOF Sheep	80	EPA 1992	Table A- 205	ASAE 1998, USDA 2008	0.19	EPA 1992	Table A- 205	ASAE 1998, USDA 2008
Goats	64	ASAE 1998	Table A- 205	ASAE 1998	0.17	EPA 1992	Table A- 205	ASAE 1998
Horses	450	ASAE 1998	Table A- 205	ASAE 1998, USDA 2008	0.33	EPA 1992	Table A- 205	ASAE 1998, USDA 2008
Mules and Asses	130	IPCC 2006	Table A- 205	IPCC 2006	0.33	EPA 1992	Table A- 205	IPCC 2006
Hens >/= 1 yr	1.8	ASAE 1998	Table A- 205	USDA 1996, 2008	0.39	Hill 1982	Table A- 205	USDA 1996, 2008
Pullets	1.8	ASAE 1998	Table A- 205	USDA 1996, 2008	0.39	Hill 1982	Table A- 205	USDA 1996, 2008
Other Chickens	1.8	ASAE 1998	Table A- 205	USDA 1996, 2008	0.39	Hill 1982	Table A- 205	USDA 1996, 2008
Broilers	0.9	ASAE 1998	Table A- 205	USDA 1996, 2008	0.36	Hill 1984	Table A- 205	USDA 1996, 2008
Turkeys	6.8	ASAE 1998	Table A- 205	USDA 1996, 2008	0.36	Hill 1984	Table A- 205	USDA 1996, 2008

[a] Nex and VS values vary by year; Table A- 203 shows state-level values for 2012 only.

Table A- 204: Estimated Volatile Solids (VS) and Total Kjeldahl Nitrogen Excreted (Nex) Production Rates by year for Swine, Poultry, Sheep, Goats, Horses, Mules and Asses, and Cattle Calves (kg/day/1000 kg animal mass)

Animal Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
VS																							
Swine, Market <50 lbs.	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
Swine, Market 50-119 lbs.	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4
Swine, Market 120-179 lbs.	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4
Swine, Market >180 lbs.	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4
Swine, Breeding	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
NOF Cattle Calves	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.5	6.6	6.7	6.8	6.9	7.1	7.2	7.3	7.4	7.5	7.6	7.7	7.7	7.7	7.7	7.7
Sheep	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.1	9.0	8.9	8.8	8.8	8.7	8.6	8.5	8.4	8.3	8.3	8.3	8.3	8.3
Goats	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5
Hens >1yr.	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Pullets	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Chickens	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.9	10.9	10.9	10.9	10.9	10.9	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
Broilers	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.2	15.3	15.5	15.7	15.8	16.0	16.2	16.3	16.5	16.7	16.8	17.0	17.0	17.0	17.0	17.0
Turkeys	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.6	9.5	9.4	9.3	9.2	9.1	9.0	8.9	8.8	8.7	8.6	8.5	8.5	8.5	8.5	8.5
Horses	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	9.6	9.2	8.8	8.4	8.1	7.7	7.3	6.9	6.5	6.1	6.1	6.1	6.1	6.1
Mules and Asses	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2
Nex																							
Swine, Market <50 lbs.	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.43	0.44	0.45	0.46	0.47	0.48	0.49	0.50	0.51	0.52	0.53	0.54	0.54	0.54	0.54	0.54
Swine, Market 50-119 lbs.	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.43	0.44	0.45	0.46	0.47	0.48	0.49	0.50	0.51	0.52	0.53	0.54	0.54	0.54	0.54	0.54
Swine, Market 120-179 lbs.	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.43	0.44	0.45	0.46	0.47	0.48	0.49	0.50	0.51	0.52	0.53	0.54	0.54	0.54	0.54	0.54
Swine, Market >180 lbs.	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.23	0.23	0.23	0.22	0.22	0.22	0.22	0.21	0.21	0.21	0.21	0.20	0.20	0.20	0.20	0.20
Swine, Breeding	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.31	0.33	0.34	0.35	0.36	0.38	0.39	0.40	0.41	0.43	0.44	0.45	0.45	0.45	0.45	0.45
NOF Cattle Calves	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.43	0.43	0.43	0.44	0.44	0.44	0.44	0.45	0.45	0.45	0.45	0.45	0.45
Sheep	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
Goats	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.71	0.72	0.73	0.73	0.74	0.75	0.76	0.77	0.77	0.78	0.79	0.79	0.79	0.79	0.79
Hens >1yr.	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.71	0.72	0.73	0.73	0.74	0.75	0.76	0.77	0.77	0.78	0.79	0.79	0.79	0.79	0.79
Pullets	0.83	0.83	0.83	0.83	0.83	0.83	0.83	0.85	0.88	0.90	0.92	0.94	0.97	0.99	1.01	1.03	1.06	1.08	1.10	1.10	1.10	1.10	1.10
Chickens	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.09	1.08	1.07	1.05	1.04	1.03	1.02	1.01	1.00	0.98	0.97	0.96	0.96	0.96	0.96	0.96
Broilers	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.73	0.72	0.71	0.70	0.69	0.68	0.67	0.66	0.65	0.64	0.63	0.63	0.63	0.63	0.63	0.63

Animal Type	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
Turkeys	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.29	0.29	0.28	0.28	0.27	0.27	0.26	0.26	0.25	0.25	0.25	0.25	0.25	0.25
Horses	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
Mules and Asses	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.43	0.44	0.45	0.46	0.47	0.48	0.49	0.50	0.51	0.52	0.53	0.54	0.54	0.54	0.54	0.54

Table A- 205: Estimated Volatile Solids (VS) and Total Kjeldahl Nitrogen Excreted (Nex) Production Rates by State for Cattle (other than Calves) and American Bison[a] for 2012 (kg/animal/year)

	Volatile Solids									Nitrogen Excreted								
State	Dairy Cow	Dairy Heifers	Beef NOF Cow	Beef NOF Heifers	Beef NOF Steer	Beef OF Heifers	Beef OF Steer	Beef NOF Bull	American Bison	Dairy Cow	Dairy Heifers	Beef NOF Cow	Beef NOF Heifers	Beef NOF Steer	Beef OF Heifers	Beef OF Steer	Beef NOF Bull	American Bison
Alabama	2,140	1,255	1,664	2,522	968	675	656	1,721	1,721	130	69	73	50	41	54	55	83	83
Alaska	2,164	1,255	1,891	3,966	1,112	675	658	1,956	1,956	130	69	59	42	33	55	56	69	69
Arizona	2,891	1,255	1,891	2,861	1,112	675	656	1,956	1,956	161	69	59	41	33	54	55	69	69
Arkansas	2,097	1,255	1,664	2,357	968	670	669	1,721	1,721	127	69	73	50	41	58	62	83	83
California	2,833	1,255	1,891	1,790	1,112	675	656	1,956	1,956	158	69	59	39	33	54	55	69	69
Colorado	2,890	1,255	1,891	1,574	1,112	675	656	1,956	1,956	161	69	59	38	33	54	55	69	69
Connecticut	2,585	1,255	1,674	2,994	974	675	656	1,731	1,731	148	69	74	52	42	54	55	84	84
Delaware	2,529	1,255	1,674	2,156	974	675	656	1,731	1,731	145	69	74	50	42	54	55	84	84
Florida	2,574	1,255	1,664	2,819	968	676	655	1,721	1,721	149	69	73	51	41	54	55	83	83
Georgia	2,582	1,255	1,664	2,458	968	675	656	1,721	1,721	149	69	73	50	41	54	55	83	83
Hawaii	2,160	1,255	1,891	2,596	1,112	675	656	1,956	1,956	129	69	59	41	33	54	55	69	69
Idaho	2,845	1,255	1,891	1,763	1,112	675	656	1,956	1,956	159	69	59	39	33	54	55	69	69
Illinois	2,557	1,255	1,589	1,464	921	675	656	1,643	1,643	146	69	75	49	43	54	55	85	85
Indiana	2,695	1,255	1,589	1,503	921	675	656	1,643	1,643	152	69	75	49	43	54	56	85	85
Iowa	2,723	1,255	1,589	1,223	921	675	656	1,643	1,643	154	69	75	48	43	54	55	85	85
Kansas	2,718	1,255	1,589	1,152	921	675	656	1,643	1,643	153	69	75	47	43	54	55	85	85
Kentucky	2,284	1,255	1,664	1,883	968	675	656	1,721	1,721	137	69	73	49	41	54	55	83	83
Louisiana	2,088	1,255	1,664	2,739	968	675	656	1,721	1,721	126	69	73	51	41	54	55	83	83
Maine	2,487	1,255	1,674	1,938	974	676	655	1,731	1,731	143	69	74	50	42	54	55	84	84
Maryland	2,533	1,255	1,674	2,203	974	675	656	1,731	1,731	145	69	74	51	42	54	55	84	84
Massachusetts	2,462	1,255	1,674	2,678	974	675	656	1,731	1,731	142	69	74	51	42	54	55	84	84
Michigan	2,870	1,255	1,589	1,563	921	675	656	1,643	1,643	160	69	75	49	43	54	55	85	85
Minnesota	2,556	1,255	1,589	1,471	921	675	656	1,643	1,643	146	69	75	49	43	54	55	85	85
Mississippi	2,226	1,255	1,664	2,476	968	676	655	1,721	1,721	134	69	73	50	41	54	55	83	83
Missouri	2,215	1,255	1,589	1,903	921	675	656	1,643	1,643	132	69	75	51	43	54	55	85	85
Montana	2,695	1,255	1,664	2,372	968	675	656	1,721	1,721	152	69	73	50	41	54	55	83	83
Nebraska	2,681	1,255	1,891	1,535	1,112	675	656	1,956	1,956	152	69	59	38	33	54	55	69	69
Nevada	2,815	1,255	1,589	1,893	921	675	656	1,643	1,643	157	69	75	51	43	54	55	85	85
New Hampshire	2,567	1,255	1,891	3,055	1,112	676	655	1,956	1,956	147	69	59	41	33	54	55	69	69
New Jersey	2,487	1,255	1,674	2,123	974	675	656	1,731	1,731	143	69	74	50	42	54	55	84	84
New Mexico	2,944	1,255	1,674	1,829	974	675	656	1,731	1,731	163	69	74	49	42	54	55	84	84
New York	2,715	1,255	1,891	2,143	1,112	675	656	1,956	1,956	153	69	59	40	33	54	55	69	69
North Carolina	2,680	1,255	1,674	2,555	974	675	656	1,731	1,731	154	69	74	51	42	54	55	84	84
North Dakota	2,539	1,255	1,664	1,873	968	675	656	1,721	1,721	146	69	73	49	41	54	55	83	83

	Volatile Solids									Nitrogen Excreted								
State	Dairy Cow	Dairy Heifers	Beef NOF Cow	Beef NOF Heifers	Beef NOF Steer	Beef OF Heifers	Beef OF Steer	Beef NOF Bull	American Bison	Dairy Cow	Dairy Heifers	Beef NOF Cow	Beef NOF Heifers	Beef NOF Steer	Beef OF Heifers	Beef OF Steer	Beef NOF Bull	American Bison
Ohio	2,581	1,255	1,589	1,698	921	675	656	1,643	1,643	147	69	75	50	43	54	55	85	85
Oklahoma	2,425	1,255	1,589	1,624	921	675	656	1,643	1,643	141	69	75	50	43	54	55	85	85
Oregon	2,625	1,255	1,664	2,019	968	675	656	1,721	1,721	149	69	73	49	41	54	55	83	83
Pennsylvania	2,562	1,255	1,891	2,076	1,112	675	656	1,956	1,956	147	69	59	40	33	54	55	69	69
Rhode Island	2,466	1,255	1,674	2,678	974	675	656	1,731	1,731	143	69	74	51	42	54	56	84	84
South Carolina	2,447	1,255	1,674	2,527	974	675	656	1,731	1,731	143	69	74	51	42	54	55	84	84
South Dakota	2,697	1,255	1,664	1,637	968	675	656	1,721	1,721	152	69	73	48	41	54	56	83	83
Tennessee	2,356	1,255	1,589	2,083	921	675	656	1,643	1,643	140	69	75	51	43	54	55	85	85
Texas	2,748	1,255	1,664	1,429	968	675	656	1,721	1,721	155	69	73	47	41	54	55	83	83
Utah	2,719	1,255	1,664	2,135	968	675	656	1,721	1,721	153	69	73	49	41	54	55	83	83
Vermont	2,542	1,255	1,891	2,062	1,112	676	656	1,956	1,956	146	69	59	40	33	54	55	69	69
Virginia	2,498	1,255	1,674	2,299	974	676	656	1,731	1,731	146	69	74	51	42	54	55	84	84
Washington	2,877	1,255	1,664	1,546	968	675	656	1,721	1,721	160	69	73	48	41	54	55	83	83
West Virginia	2,279	1,255	1,891	2,452	1,112	675	656	1,956	1,956	134	69	59	40	33	54	55	69	69
Wisconsin	2,701	1,255	1,589	2,183	921	675	656	1,643	1,643	153	69	75	51	43	54	55	85	85
Wyoming	2,654	1,255	1,891	2,331	1,112	675	656	1,956	1,956	151	69	59	40	33	54	55	69	69

Source: CEFM

[a] Beef NOF Bull values were used for American bison Nex and VS.

Table A- 206: 2012 Manure Distribution Among Waste Management Systems by Operation (Percent)

	Beef Feedlots		Beef Not on Feed Operations	Dairy Cow Farms[a]						Dairy Heifer Facilities				Swine Operations[a]					Layer Operations		Broiler and Turkey Operations	
State	Dry Lot[b]	Liquid/ Slurry[b]	Pasture, Range, Paddock	Pasture, Range, Paddock	Daily Spread	Solid Storage	Liquid/ Slurry	Anaerobic Lagoon	Deep Pit	Daily Spread[b]	Dry Lot[b]	Liquid/ Slurry[b]	Pasture, Range, Paddock[b]	Pasture, Range, Paddock	Solid Storage	Liquid/ Slurry	Anaerobic Lagoon	Deep Pit	Anaerobic Lagoon	Poultry without Litter	Pasture, Range, Paddock	Poultry with Litter
Alabama	100	1	100	51	16	7	10	16	0	17	38	0	45	5	4	7	54	31	42	58	1	99
Alaska	100	1	100	5	9	34	19	24	9	6	90	1	4	64	2	10	7	17	25	75	1	99
Arizona	100	0	100	0	10	9	19	61	0	10	90	0	0	6	3	6	55	29	60	40	1	99
Arkansas	100	1	100	60	14	10	7	9	0	15	28	0	57	4	4	13	45	35	0	100	1	99
California	100	1	100	1	11	9	20	59	0	11	88	1	1	10	3	7	50	29	12	88	1	99
Colorado	100	0	100	1	1	11	23	64	0	1	98	0	1	1	6	26	17	50	60	40	1	99
Connecticut	100	1	100	6	43	16	20	13	2	43	51	0	6	78	1	6	5	11	5	95	1	99
Delaware	100	1	100	6	44	19	19	10	2	44	50	0	6	8	5	25	17	46	5	95	1	99
Florida	100	1	100	13	22	7	15	43	0	22	61	1	17	72	1	8	6	13	42	58	1	99
Georgia	100	1	100	37	18	9	12	23	0	18	42	0	40	4	4	8	53	31	42	58	1	99
Hawaii	100	1	100	10	0	9	23	57	0	0	99	1	1	31	3	19	14	32	25	75	1	99
Idaho	100	0	100	0	0	11	23	65	0	1	99	0	0	12	5	23	15	44	60	40	1	99
Illinois	100	1	100	4	6	39	31	16	5	8	87	0	5	1	5	29	14	52	2	98	1	99
Indiana	100	1	100	5	8	29	31	24	3	13	79	0	8	1	5	28	14	52	0	100	1	99
Iowa	100	1	100	4	8	34	30	20	4	10	83	0	6	1	4	9	54	33	0	100	1	99
Kansas	100	1	100	2	3	21	37	36	2	5	92	0	3	2	5	28	13	52	2	98	1	99
Kentucky	100	1	100	60	14	14	7	3	2	14	24	0	61	5	4	10	48	33	5	95	1	99

	Beef Feedlots		Beef Not on Feed Operations	Dairy Cow Farms[a]						Dairy Heifer Facilities				Swine Operations[a]					Layer Operations		Broiler and Turkey Operations	
State	Dry Lot[b]	Liquid/ Slurry[b]	Pasture, Range, Paddock	Pasture, Range, Paddock	Daily Spread	Solid Storage	Liquid/ Slurry	Anaerobic Lagoon	Deep Pit	Daily Spread[b]	Dry Lot[b]	Liquid/ Slurry[b]	Pasture, Range, Paddock[b]	Pasture, Range, Paddock	Solid Storage	Liquid/ Slurry	Anaerobic Lagoon	Deep Pit	Anaerobic Lagoon	Poultry without Litter	Pasture, Range, Paddock	Poultry with Litter
Louisiana	100	1	100	59	15	10	7	9	1	14	26	0	60	88	1	3	3	6	60	40	1	99
Maine	100	1	100	7	45	20	17	10	2	45	48	0	7	65	2	10	7	16	5	95	1	99
Maryland	100	1	100	7	44	22	16	8	3	44	49	0	7	7	5	25	17	47	5	95	1	99
Massachusetts	100	1	100	7	44	22	16	8	3	45	47	0	7	56	2	12	9	20	5	95	1	99
Michigan	100	1	100	2	4	24	38	29	3	6	91	0	3	4	5	26	17	48	2	98	1	99
Minnesota	100	1	100	5	8	39	28	17	4	10	84	0	6	1	5	26	18	50	0	100	1	99
Mississippi	100	1	100	54	15	10	8	12	0	15	28	0	57	2	4	6	58	31	60	40	1	99
Missouri	100	1	100	7	12	42	22	11	5	14	77	0	8	2	5	28	13	52	0	100	1	99
Montana	100	0	100	2	4	19	28	42	4	4	93	0	3	3	5	25	17	49	60	40	1	99
Nebraska	100	1	100	2	4	26	35	29	3	6	90	0	4	1	5	28	14	51	2	98	1	99
Nevada	100	0	100	0	0	10	24	65	0	0	99	0	0	34	3	18	14	31	0	100	1	99
New Hampshire	100	1	100	7	44	19	18	10	2	44	49	0	7	64	2	10	8	17	5	95	1	99
New Jersey	100	1	100	7	45	25	13	6	3	45	47	0	8	36	3	18	14	30	5	95	1	99
New Mexico	100	0	100	0	10	9	19	61	0	10	90	0	0	100	0	0	0	0	60	40	1	99
New York	100	1	100	6	44	17	18	13	2	45	48	0	7	13	5	23	15	44	5	95	1	99
North Carolina	100	1	100	46	17	11	15	10	2	15	31	0	54	0	4	7	57	32	42	58	1	99
North Dakota	100	1	100	7	11	38	26	15	4	11	83	0	6	5	5	25	17	48	2	98	1	99
Ohio	100	1	100	6	11	38	26	15	4	14	78	0	8	3	5	28	14	51	0	100	1	99
Oklahoma	100	0	100	0	7	21	22	45	4	6	94	0	0	1	4	6	58	31	60	40	1	99
Oregon	100	1	100	16	0	11	22	50	1	0	80	1	20	48	2	14	11	24	25	75	1	99
Pennsylvania	100	1	100	8	46	24	12	6	2	47	44	0	9	4	5	26	18	48	0	100	1	99
Rhode Island	100	1	100	9	47	25	13	5	2	47	44	0	9	72	1	8	6	13	5	95	1	99
South Carolina	100	1	100	47	17	8	11	18	0	15	31	0	54	3	4	7	55	31	60	40	1	99
South Dakota	100	1	100	3	4	24	36	31	2	8	87	0	5	1	5	26	17	50	2	98	1	99
Tennessee	100	1	100	58	15	12	9	4	2	15	26	0	59	13	3	11	41	32	5	95	1	99
Texas	100	0	100	0	9	11	22	58	1	8	92	0	0	3	4	6	57	30	12	88	1	99
Utah	100	0	100	1	1	15	26	56	2	1	98	0	1	1	6	26	17	51	60	40	1	99
Vermont	100	1	100	6	44	17	19	13	2	44	49	0	7	63	2	10	8	18	5	95	1	99
Virginia	100	1	100	56	15	11	10	5	2	15	28	0	57	4	4	7	54	31	5	95	1	99
Washington	100	1	100	11	0	11	22	56	1	0	83	1	17	43	3	15	11	28	12	88	1	99
West Virginia	100	1	100	8	46	23	14	7	2	45	48	0	7	59	2	11	7	20	5	95	1	99
Wisconsin	100	1	100	5	9	38	28	17	4	12	82	0	7	13	4	23	17	42	2	98	1	99
Wyoming	100	0	100	4	6	19	23	43	4	12	81	0	7	4	5	25	16	49	60	40	1	99

[a] In the methane inventory for manure management, the percent of dairy cows and swine with AD systems is estimated using data from EPA's AgSTAR Program.

[b] Because manure from beef feedlots and dairy heifers may be managed for long periods of time in multiple systems (i.e., both drylot and runoff collection pond), the percent of manure that generates emissions is greater than 100 percent.

Table A- 207: Manure Management System Descriptions

Manure Management System	Description[a]
Pasture, Range, Paddock	The manure from pasture and range grazing animals is allowed to lie as is, and is not managed. Methane emissions are accounted for under Manure Management, but the N_2O emissions from manure deposited on PRP are included under the Agricultural Soil Management category.
Daily Spread	Manure is routinely removed from a confinement facility and is applied to cropland or pasture within 24 hours of excretion. Methane emissions are accounted for under Manure Management, but the N_2O emissions during storage and treatment are assumed to be zero. N_2O emissions from land application are covered under the Agricultural Soil Management category.
Solid Storage	The storage of manure, typically for a period of several months, in unconfined piles or stacks. Manure is able to be stacked due to the presence of a sufficient amount of bedding material or loss of moisture by evaporation.
Dry Lot	A paved or unpaved open confinement area without any significant vegetative cover where accumulating manure may be removed periodically. Dry lots are most typically found in dry climates but also are used in humid climates.
Liquid/ Slurry	Manure is stored as excreted or with some minimal addition of water to facilitate handling and is stored in either tanks or earthen ponds, usually for periods less than one year.
Anaerobic Lagoon	Uncovered anaerobic lagoons are designed and operated to combine waste stabilization and storage. Lagoon supernatant is usually used to remove manure from the associated confinement facilities to the lagoon. Anaerobic lagoons are designed with varying lengths of storage (up to a year or greater), depending on the climate region, the VS loading rate, and other operational factors. Anaerobic lagoons accumulate sludge over time, diminishing treatment capacity. Lagoons must be cleaned out once every 5 to 15 years, and the sludge is typically applied to agricultural lands. The water from the lagoon may be recycled as flush water or used to irrigate and fertilize fields. Lagoons are sometimes used in combination with a solids separator, typically for dairy waste. Solids separators help control the buildup of nondegradable material such as straw or other bedding materials.
Anaerobic Digester	Animal excreta with or without straw are collected and anaerobically digested in a large containment vessel (complete mix or plug flow digester) or covered lagoon. Digesters are designed and operated for waste stabilization by the microbial reduction of complex organic compounds to CO_2 and CH_4, which is captured and flared or used as a fuel.
Deep Pit	Collection and storage of manure usually with little or no added water typically below a slatted floor in an enclosed animal confinement facility. Typical storage periods range from 5 to 12 months, after which manure is removed from the pit and transferred to a treatment system or applied to land.
Poultry with Litter	Enclosed poultry houses use bedding derived from wood shavings, rice hulls, chopped straw, peanut hulls, or other products, depending on availability. The bedding absorbs moisture and dilutes the manure produced by the birds. Litter is typically cleaned out completely once a year. These manure systems are typically used for all poultry breeder flocks and for the production of meat type chickens (broilers) and other fowl.
Poultry without Litter	In high-rise cages or scrape-out/belt systems, manure is excreted onto the floor below with no bedding to absorb moisture. The ventilation system dries the manure as it is stored. When designed and operated properly, this high-rise system is a form of passive windrow composting.

[a] Manure management system descriptions are based on the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (Volume 4: Agriculture, Forestry and Other Land Use, Chapter 10: Emissions from Livestock and Manure Management, Tables 10.18 and 10.21) and the *Development Document for the Final Revisions to the National Pollutant Discharge Elimination System Regulation and the Effluent Guidelines for Concentrated Animal Feeding Operations* (EPA-821-R-03-001, December 2002).

Table A- 208: Methane Conversion Factors (percent) for Dry Systems

Waste Management System	Cool Climate MCF	Temperate Climate MCF	Warm Climate MCF
Aerobic Treatment	0	0	0
Anaerobic Digester	0	0	0
Cattle Deep Litter (<1 month)	0.03	0.03	0.3
Cattle Deep Litter (>1 month)	0.21	0.44	0.76
Composting - In Vessel	0.005	0.005	0.005

Waste Management System	Cool Climate MCF	Temperate Climate MCF	Warm Climate MCF
Composting - Static Pile	0.005	0.005	0.005
Composting-Extensive/ Passive	0.005	0.01	0.015
Composting-Intensive	0.005	0.01	0.015
Daily Spread	0.001	0.005	0.01
Dry Lot	0.01	0.015	0.05
Fuel	0.1	0.1	0.1
Pasture	0.01	0.015	0.02
Poultry with bedding	0.015	0.015	0.015
Poultry without bedding	0.015	0.015	0.015
Solid Storage	0.02	0.04	0.05

Source: IPCC 2006

Table A- 209: Methane Conversion Factors by State for Liquid Systems for 2012 (percent)

	Dairy		Swine		Beef	Poultry
State	Anaerobic Lagoon	Liquid/Slurry and Deep Pit	Anaerobic Lagoon	Liquid/Slurry and Deep Pit	Liquid/Slurry	Anaerobic Lagoon
Alabama	0.77	0.41	0.76	0.40	0.42	0.76
Alaska	0.47	0.15	0.47	0.15	0.15	0.47
Arizona	0.79	0.58	0.78	0.49	0.54	0.75
Arkansas	0.76	0.39	0.77	0.43	0.40	0.76
California	0.75	0.33	0.73	0.31	0.41	0.75
Colorado	0.65	0.22	0.68	0.24	0.24	0.65
Connecticut	0.70	0.26	0.71	0.26	0.26	0.70
Delaware	0.76	0.35	0.76	0.35	0.35	0.76
Florida	0.80	0.55	0.80	0.54	0.54	0.80
Georgia	0.78	0.44	0.77	0.42	0.42	0.76
Hawaii	0.76	0.57	0.76	0.57	0.57	0.76
Idaho	0.67	0.23	0.65	0.21	0.21	0.67
Illinois	0.73	0.31	0.72	0.30	0.29	0.73
Indiana	0.71	0.28	0.72	0.29	0.29	0.72
Iowa	0.70	0.26	0.70	0.26	0.26	0.70
Kansas	0.75	0.36	0.75	0.35	0.35	0.75
Kentucky	0.74	0.33	0.74	0.33	0.32	0.74
Louisiana	0.78	0.48	0.78	0.50	0.50	0.78
Maine	0.65	0.21	0.65	0.21	0.21	0.65
Maryland	0.74	0.32	0.74	0.32	0.33	0.75
Massachusetts	0.68	0.24	0.69	0.25	0.25	0.69
Michigan	0.68	0.24	0.69	0.25	0.24	0.68
Minnesota	0.68	0.24	0.69	0.25	0.25	0.67
Mississippi	0.77	0.44	0.76	0.42	0.44	0.77
Missouri	0.74	0.34	0.74	0.33	0.33	0.74
Montana	0.61	0.19	0.63	0.20	0.21	0.63
Nebraska	0.71	0.27	0.71	0.28	0.27	0.71
Nevada	0.69	0.24	0.71	0.26	0.23	0.70
New Hampshire	0.66	0.23	0.67	0.23	0.22	0.67
New Jersey	0.73	0.31	0.74	0.31	0.30	0.74
New Mexico	0.75	0.35	0.73	0.30	0.32	0.71
New York	0.68	0.24	0.69	0.24	0.24	0.69
North Carolina	0.75	0.34	0.77	0.40	0.32	0.75
North Dakota	0.66	0.22	0.66	0.22	0.22	0.65
Ohio	0.71	0.28	0.72	0.28	0.28	0.71
Oklahoma	0.77	0.47	0.77	0.43	0.44	0.77
Oregon	0.63	0.20	0.64	0.20	0.22	0.64
Pennsylvania	0.71	0.28	0.72	0.29	0.28	0.72
Rhode Island	0.71	0.27	0.71	0.27	0.27	0.71
South Carolina	0.77	0.42	0.78	0.43	0.41	0.77
South Dakota	0.69	0.25	0.70	0.25	0.25	0.69
Tennessee	0.74	0.33	0.75	0.36	0.34	0.74
Texas	0.77	0.48	0.78	0.50	0.44	0.78
Utah	0.67	0.23	0.69	0.24	0.24	0.67
Vermont	0.65	0.22	0.65	0.22	0.22	0.66
Virginia	0.73	0.30	0.75	0.34	0.31	0.74
Washington	0.63	0.20	0.64	0.21	0.22	0.64
West Virginia	0.71	0.28	0.71	0.28	0.28	0.71

State	Dairy		Swine		Beef	Poultry
	Anaerobic Lagoon	Liquid/Slurry and Deep Pit	Anaerobic Lagoon	Liquid/Slurry and Deep Pit	Liquid/Slurry	Anaerobic Lagoon
Wisconsin	0.67	0.23	0.68	0.24	0.24	0.68
Wyoming	0.63	0.20	0.64	0.21	0.22	0.64

Note: MCFs developed using Tier 2 methods described in IPCC 2006, Section 10.4.2.

Table A- 210: Direct Nitrous Oxide Emission Factors for 2012 (kg N_2O-N/kg Kjdl N)

Waste Management System	Direct N_2O Emission Factor
Aerobic Treatment (forced aeration)	0.005
Aerobic Treatment (natural aeration)	0.01
Anaerobic Digester	0
Anaerobic Lagoon	0
Cattle Deep Bed (active mix)	0.07
Cattle Deep Bed (no mix)	0.01
Composting_in vessel	0.006
Composting_intensive	0.1
Composting_passive	0.01
Composting_static	0.006
Daily Spread	0
Deep Pit	0.002
Dry Lot	0.02
Fuel	0
Liquid/Slurry	0.005
Pasture	0
Poultry with bedding	0.001
Poultry without bedding	0.001
Solid Storage	0.005

Source: IPCC 2006

Table A- 211: Indirect Nitrous Oxide Loss Factors (percent)

			Runoff/Leaching Nitrogen Loss[a]				
Animal Type	Waste Management System	Volatilization Nitrogen Loss	Central	Pacific	Mid-Atlantic	Midwest	South
Beef Cattle	Dry Lot	23	1.1	3.9	3.6	1.9	4.3
Beef Cattle	Liquid/Slurry	26	0	0	0	0	0
Beef Cattle	Pasture	0	0	0	0	0	0
Dairy Cattle	Anaerobic Lagoon	43	0.2	0.8	0.7	0.4	0.9
Dairy Cattle	Daily Spread	10	0	0	0	0	0
Dairy Cattle	Deep Pit	24	0	0	0	0	0
Dairy Cattle	Dry Lot	15	0.6	2	1.8	0.9	2.2
Dairy Cattle	Liquid/Slurry	26	0.2	0.8	0.7	0.4	0.9
Dairy Cattle	Pasture	0	0	0	0	0	0
Dairy Cattle	Solid Storage	27	0.2	0	0	0	0
American Bison	Pasture	0	0	0	0	0	0
Goats	Dry Lot	23	1.1	3.9	3.6	1.9	4.3
Goats	Pasture	0	0	0	0	0	0
Horses	Dry Lot	23	0	0	0	0	0
Horses	Pasture	0	0	0	0	0	0
Mules and Asses	Dry Lot	23	0	0	0	0	0
Mules and Asses	Pasture	0	0	0	0	0	0
Poultry	Anaerobic Lagoon	54	0.2	0.8	0.7	0.4	0.9
Poultry	Liquid/Slurry	26	0.2	0.8	0.7	0.4	0.9
Poultry	Pasture	0	0	0	0	0	0
Poultry	Poultry with bedding	26	0	0	0	0	0
Poultry	Poultry without bedding	34	0	0	0	0	0
Poultry	Solid Storage	8	0	0	0	0	0
Sheep	Dry Lot	23	1.1	3.9	3.6	1.9	4.3
Sheep	Pasture	0	0	0	0	0	0
Swine	Anaerobic Lagoon	58	0.2	0.8	0.7	0.4	0.9
Swine	Deep Pit	34	0	0	0	0	0
Swine	Liquid/Slurry	26	0.2	0.8	0.7	0.4	0.9
Swine	Pasture	0	0	0	0	0	0
Swine	Solid Storage	45	0	0	0	0	0

Source: EPA 2002b, 2005.

[a] Data for nitrogen losses due to leaching were not available, so the values represent only nitrogen losses due to runoff.

Table A- 212: Methane Emissions from Livestock Manure Management (Gg)[a]

Animal Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Dairy Cattle	599	615	598	623	663	693	702	734	781	854	900	960	997	1047	1000	1069	1101	1224	1238	1233	1239	1262	1291
Dairy Cows	592	608	591	616	656	686	695	727	774	846	893	952	990	1039	993	1062	1094	1216	1230	1225	1231	1254	1283
Dairy Heifer	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	8	8	8	8	8	9
Swine	624	676	639	680	741	764	730	783	892	849	834	854	879	860	857	914	901	982	938	896	948	941	957
Market Swine	484	524	500	534	585	608	582	626	720	692	680	696	720	706	706	753	741	814	780	748	792	787	801
Market <50 lbs.	102	110	104	109	119	121	116	125	141	133	131	134	137	135	135	142	141	155	109	103	110	110	112
Market 50-119 lbs.	101	111	105	110	120	124	117	127	144	138	136	138	144	140	141	150	148	163	174	167	177	176	180
Market 120-179 lbs.	136	147	140	151	164	170	163	175	201	193	189	192	199	196	196	210	206	227	229	218	231	228	233
Market >180 lbs.	145	156	152	165	182	194	185	198	235	229	225	232	240	234	234	251	246	269	268	259	273	272	276
Breeding Swine	140	152	139	146	156	155	148	157	172	157	155	158	158	154	151	161	160	168	157	148	156	154	156
Beef Cattle	128	128	131	131	137	141	139	136	139	139	133	136	133	133	131	135	138	136	132	131	134	132	128
Feedlot Steers	14	14	14	13	14	14	14	13	13	14	15	15	15	16	15	15	16	16	16	16	16	17	16
Feedlot Heifers	7	7	7	7	8	8	8	8	8	8	9	9	9	9	9	9	9	9	9	9	9	9	9
NOF Bulls	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
NOF Calves	8	8	8	8	9	9	8	8	9	9	9	9	9	9	9	9	10	10	9	9	9	9	9
NOF Heifers	12	12	13	14	14	15	15	14	15	14	13	13	13	13	12	13	13	13	13	13	13	12	12
NOF Steers	12	12	13	14	13	14	14	13	13	12	11	11	11	10	10	10	10	11	10	11	11	10	9
NOF Cows	69	69	70	71	74	76	76	74	76	76	71	73	71	71	71	73	74	73	70	69	71	70	68
Sheep	7	7	7	6	6	5	5	5	5	4	4	4	4	4	3	3	3	3	3	3	3	3	3
Goats	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Poultry	131	132	127	131	131	128	126	128	130	126	127	131	129	130	129	129	131	134	129	128	129	127	127
Hens >1 yr.	73	72	70	73	72	69	68	67	70	66	67	70	67	68	66	66	66	67	64	64	64	64	64
Total Pullets	25	26	23	23	23	22	21	23	23	21	22	22	22	22	23	22	23	25	23	23	24	23	24
Chickens	4	4	4	4	4	4	3	3	4	4	3	3	4	4	3	3	3	3	3	4	3	3	3
Broilers	19	20	20	21	22	23	24	25	26	27	28	28	29	29	30	31	32	32	33	31	31	31	31
Turkeys	10	10	10	10	9	9	9	9	8	7	7	7	7	7	7	7	7	7	7	6	6	6	6
Horses	9	9	9	9	10	11	11	12	13	13	13	13	13	13	12	12	12	11	10	11	11	11	12
Mules and Asses	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
American Bison	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+

[a] Accounts for CH_4 reductions due to capture and destruction of CH_4 at facilities using anaerobic digesters.

+ Emission estimate is less than 0.5 Gg.

Table A- 213: Total (Direct and Indirect) Nitrous Oxide Emissions from Livestock Manure Management (Gg)

Animal Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Dairy Cattle	17.1	17.0	17.0	17.3	17.4	17.7	17.7	17.9	18.0	17.6	17.9	18.2	18.5	18.7	17.8	18.3	18.9	18.9	18.6	18.8	18.9	19.1	19.4
Dairy Cows	10.0	10.1	10.0	10.0	10.1	10.3	10.3	10.4	10.5	10.2	10.5	10.5	10.6	10.8	10.3	10.5	10.8	10.8	10.6	10.8	10.6	10.8	11.0
Dairy Heifer	7.0	6.9	7.1	7.2	7.3	7.4	7.4	7.4	7.5	7.4	7.5	7.7	7.8	7.9	7.5	7.8	8.1	8.1	8.0	8.0	8.2	8.3	8.4
Swine	4.0	4.2	4.3	4.4	4.6	4.5	4.4	4.7	5.1	5.0	5.0	5.1	5.3	5.4	5.6	5.7	5.9	6.3	6.5	6.3	6.2	6.3	6.4
Market Swine	3.0	3.1	3.3	3.3	3.5	3.5	3.3	3.6	4.0	4.1	4.1	4.2	4.4	4.5	4.7	4.9	5.0	5.5	5.6	5.5	5.4	5.5	5.6
Market <50 lbs.	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.0	1.1	0.8	0.8	0.8	0.8	0.8
Market 50-119 lbs.	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.9	0.9	0.9	1.0	1.0	1.1	1.3	1.2	1.2	1.2	1.3
Market 120-179 lbs.	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.1	1.1	1.1	1.2	1.2	1.3	1.3	1.4	1.4	1.5	1.6	1.6	1.6	1.6	1.6
Market >180 lbs.	0.9	1.0	1.0	1.0	1.1	1.1	1.1	1.2	1.3	1.3	1.3	1.4	1.5	1.5	1.6	1.6	1.6	1.8	1.9	1.9	1.8	1.9	1.9
Breeding Swine	1.0	1.1	1.1	1.1	1.1	1.1	1.0	1.1	1.1	1.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.8	0.8	0.8	0.8	0.8
Beef Cattle	19.8	20.3	20.1	19.1	20.9	21.8	21.4	21.5	21.6	24.0	25.0	24.1	24.8	25.0	23.6	24.0	25.7	25.6	25.2	25.1	25.3	25.8	25.6
Feedlot Steers	13.4	13.6	13.5	12.8	13.9	14.4	14.0	13.9	14.1	15.5	16.1	15.4	16.0	16.3	15.3	15.5	16.7	16.7	16.5	16.5	16.6	16.8	16.6
Feedlot Heifers	6.4	6.6	6.6	6.3	7.0	7.4	7.4	7.6	7.6	8.5	8.9	8.6	8.7	8.8	8.4	8.5	9.0	8.9	8.7	8.6	8.7	9.0	9.0
Sheep	0.4	0.4	0.4	0.4	0.6	0.7	0.8	0.9	0.9	1.0	1.1	1.2	1.2	1.2	1.1	1.2	1.2	1.2	1.2	1.1	1.1	1.1	1.1
Goats	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Poultry	4.7	4.8	4.9	5.0	5.1	5.1	5.3	5.3	5.3	5.3	5.3	5.3	5.4	5.3	5.4	5.4	5.4	5.4	5.4	5.2	5.2	5.2	5.1
Hens >1 yr.	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.1	1.1	1.1	1.1	1.2	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Total Pullets	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Chickens	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Broilers	2.2	2.3	2.4	2.5	2.6	2.7	2.8	2.8	2.9	2.9	2.9	2.9	3.0	2.9	2.9	3.0	2.9	2.9	2.9	2.7	2.8	2.8	2.7
Turkeys	1.2	1.2	1.2	1.1	1.1	1.1	1.1	1.1	1.0	0.9	0.9	0.9	0.9	0.9	0.8	0.8	0.8	0.8	0.8	0.7	0.7	0.7	0.7
Horses	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Mules and Asses	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
American Bison	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

+ Emission estimate is less than 0.5 Gg.

Note: American bison are maintained entirely on unmanaged WMS; there are no American bison N_2O emissions from managed systems.

Table A- 214: Methane Emissions by State from Livestock Manure Management for 2012 (Gg)[a]

State	Beef on Feedlots	Beef Not on Feed[b]	Dairy Cow	Dairy Heifer	Swine—Market	Swine—Breeding	Layer	Broiler	Turkey	Sheep	Goats	Horses	Mules and Asses	American Bison
Alabama	0.0336	2.4197	0.5926	0.0161	2.0727	0.5977	8.7998	3.6453	0.0267	0.0085	0.0302	0.3572	0.0203	0.0006
Alaska	0.0001	0.0212	0.0281	0.0003	0.0020	0.0010	0.1918	+	0.0266	0.0057	0.0001	0.0057	0.0001	0.0038
Arizona	0.6397	1.0594	52.3809	0.1643	2.7052	0.7384	0.6810	+	0.0267	0.0987	0.0158	0.2977	0.0039	0.0011
Arkansas	0.0026	3.3507	0.3986	0.0133	0.6992	2.1303	0.5260	3.5490	0.7252	0.0085	0.0190	0.2814	0.0139	0.0016
California	1.3823	4.0028	407.5697	2.1559	1.5979	0.1513	4.3435	0.1939	0.3876	0.4017	0.0490	0.7540	0.0133	0.0101
Colorado	1.7186	2.8226	28.3952	0.1119	4.8006	2.7184	3.5109	+	0.0266	0.2161	0.0122	0.2869	0.0060	0.0412
Connecticut	0.0006	0.0192	1.0254	0.0161	0.0040	0.0027	0.2534	+	0.0266	0.0035	0.0011	0.0296	0.0005	0.0001
Delaware	0.0007	0.0112	0.3107	0.0059	0.0280	0.0191	0.0773	0.7675	0.0266	0.0057	0.0009	0.0098	0.0001	+
Florida	0.0187	3.3388	21.0759	0.1008	0.0581	0.0376	6.2130	0.2161	0.0267	0.0085	0.0216	0.4643	0.0122	0.0047
Georgia	0.0246	1.8624	7.4419	0.0841	2.2272	0.8186	14.7767	4.9460	0.0267	0.0085	0.0315	0.2609	0.0171	0.0017
Hawaii	0.0048	0.3194	0.3757	0.0029	0.1056	0.0639	0.2996	+	0.0267	0.0085	0.0034	0.0280	0.0005	0.0006
Idaho	0.3558	1.6026	121.2554	0.4488	0.1854	0.0941	0.6031	+	0.0266	0.1128	0.0044	0.1420	0.0047	+
Illinois	0.2545	0.9485	8.8046	0.0759	43.2643	10.7696	0.2349	0.1932	0.0266	0.0268	0.0084	0.2175	0.0053	0.0028
Indiana	0.1772	0.6055	14.2386	0.1118	35.9163	5.9036	0.8871	0.1932	0.4113	0.0258	0.0118	0.1400	0.0050	0.0033
Iowa	2.0677	3.0499	20.7412	0.2534	298.3233	31.2223	1.6782	0.1932	0.0266	0.0916	0.0140	0.1465	0.0047	0.0056
Kansas	3.9061	5.0245	21.7396	0.1402	21.5870	4.0160	0.0441	+	0.0266	0.0329	0.0124	0.2461	0.0056	0.0210
Kentucky	0.0180	2.5696	1.5901	0.0797	4.7269	1.1379	0.5523	1.1204	0.0266	0.0188	0.0245	0.4414	0.0146	0.0003
Louisiana	0.0175	1.6358	0.7189	0.0167	0.0127	0.0099	2.1974	0.1939	0.0267	0.0085	0.0081	0.2407	0.0095	0.0005
Maine	0.0018	0.0371	1.3859	0.0263	0.0096	0.0069	0.2850	+	0.0266	0.0035	0.0015	0.0254	0.0005	0.0008
Maryland	0.0181	0.1329	2.6381	0.0493	0.1784	0.0565	0.2867	1.1005	0.0266	0.0057	0.0042	0.0779	0.0014	0.0024
Massachusetts	0.0007	0.0245	0.4907	0.0100	0.0428	0.0093	0.0120	+	0.0266	0.0035	0.0021	0.0562	0.0013	0.0001
Michigan	0.2390	0.4683	46.7963	0.2481	8.8211	2.0014	0.7397	0.1932	0.0266	0.0371	0.0070	0.2132	0.0054	0.0059
Minnesota	0.4858	1.3667	32.0661	0.4477	66.0579	10.9262	0.3392	0.1647	1.1466	0.0705	0.0092	0.1917	0.0046	0.0004
Mississippi	0.0338	1.8562	0.6039	0.0190	5.8406	1.9556	7.6372	2.7289	0.0267	0.0085	0.0115	0.2098	0.0134	+
Missouri	0.0878	4.5551	6.1014	0.0656	23.2430	7.8459	0.2893	0.9832	0.4362	0.0390	0.0241	0.3438	0.0145	0.0038
Montana	0.0465	3.5868	1.7686	0.0119	1.1836	0.3580	0.3657	+	0.0266	0.1057	0.0031	0.2543	0.0042	0.0186
Nebraska	4.1448	7.0122	7.5325	0.0239	26.3869	7.7471	0.5646	0.1932	0.0266	0.0362	0.0086	0.1584	0.0031	0.0468
Nevada	0.0107	0.5581	6.6532	0.0150	0.0172	0.0042	0.0223	+	0.0266	0.0329	0.0030	0.0453	0.0005	0.0004
New Hampshire	0.0004	0.0160	0.6541	0.0108	0.0111	0.0052	0.0705	+	0.0266	0.0035	0.0010	0.0260	0.0009	0.0001
New Jersey	0.0008	0.0235	0.2943	0.0070	0.0600	0.0160	0.0758	+	0.0266	0.0057	0.0027	0.0731	0.0014	0.0003
New Mexico	0.0406	1.1678	82.3978	0.1855	0.0003	0.0003	0.6441	+	0.0266	0.0470	0.0089	0.1326	0.0022	0.0074
New York	0.0421	0.4686	31.8012	0.5337	0.5247	0.1025	0.5093	0.1932	0.0266	0.0291	0.0100	0.2075	0.0032	0.0035
North Carolina	0.0149	0.9605	2.7022	0.0522	141.3090	32.2132	11.0142	2.9047	0.9003	0.0183	0.0369	0.3041	0.0167	0.0013
North Dakota	0.0922	2.1982	1.2472	0.0156	0.7981	0.6028	0.0413	+	0.0266	0.0343	0.0011	0.1009	0.0011	0.0018
Ohio	0.2825	0.8934	20.5114	0.1915	18.4559	3.3987	0.9321	0.2288	0.1371	0.0592	0.0174	0.2279	0.0072	+
Oklahoma	0.8635	7.2239	9.6670	0.0459	35.0261	15.7762	3.4508	0.7693	0.0267	0.0493	0.0470	0.5946	0.0252	0.0202
Oregon	0.1238	1.4227	17.4305	0.1266	0.0458	0.0290	0.8411	0.1932	0.0266	0.0940	0.0095	0.1893	0.0050	0.0010

State	Beef on Feedlots	Beef Not on Feed[b]	Dairy Cow	Dairy Heifer	Swine—Market	Swine—Breeding	Layer	Broiler	Turkey	Sheep	Goats	Horses	Mules and Asses	American Bison
Pennsylvania	0.1306	0.7368	17.4491	0.5388	10.7082	2.0211	0.7737	0.5593	0.1745	0.0418	0.0148	0.2612	0.0119	0.0042
Rhode Island	0.0001	0.0036	0.0358	0.0009	0.0039	0.0046	0.0741	+	0.0266	0.0035	0.0002	0.0110	0.0001	+
South Carolina	0.0097	0.7102	1.2038	0.0161	4.8058	0.3713	4.9170	0.8093	0.3001	0.0085	0.0163	0.1506	0.0089	0.0004
South Dakota	0.5241	4.2889	11.6592	0.0552	10.5354	3.4490	0.1377	+	0.1147	0.1339	0.0027	0.1553	0.0021	0.0721
Tennessee	0.0167	2.3424	1.4279	0.0533	2.2084	0.4569	0.2311	0.6067	0.0266	0.0164	0.0327	0.2965	0.0227	0.0017
Texas	6.6601	19.1277	102.5671	0.4834	14.0303	3.0580	4.5769	2.1884	0.0267	0.4722	0.4273	1.6602	0.1112	0.0194
Utah	0.0383	0.8478	16.9664	0.0793	5.6764	1.4043	3.2231	+	0.1022	0.1433	0.0043	0.1275	0.0025	0.0045
Vermont	0.0019	0.0628	6.0471	0.0889	0.0131	0.0045	0.0183	+	0.0266	0.0035	0.0016	0.0336	0.0011	0.0003
Virginia	0.0399	1.7150	2.9815	0.0696	3.9370	0.1651	0.3398	0.8706	0.4237	0.0395	0.0158	0.2177	0.0082	0.0021
Washington	0.4017	0.7238	45.8262	0.2024	0.1247	0.0626	1.2451	0.1932	0.0266	0.0244	0.0082	0.2268	0.0046	0.0029
West Virginia	0.0087	0.5604	0.3619	0.0086	0.0235	0.0185	0.1649	0.3403	0.0823	0.0155	0.0070	0.0955	0.0032	0.0005
Wisconsin	0.3756	1.1479	93.7919	1.0791	2.2459	0.8086	0.3269	0.1872	0.0266	0.0395	0.0140	0.3025	0.0070	0.0073
Wyoming	0.1082	2.0454	0.8400	0.0074	0.2272	0.3644	0.0087	+	0.0266	0.1739	0.0021	0.2147	0.0028	0.0277

+ Emission estimate is less than 0.00005 Gg.

[a] Accounts for CH_4 reductions due to capture and destruction of CH_4 at facilities using anaerobic digesters.

[b] Beef Not on Feed includes calves.

Table A- 215: Nitrous Oxide Emissions by State from Livestock Manure Management for 2012 (Gg)

State	Beef Feedlot-Heifer	Beef Feedlot-Steers	Dairy Cow	Dairy Heifer	Swine-Market	Swine-Breeding	Layer	Broiler	Turkey	Sheep	Goats	Horses	Mules and Asses
Alabama	0.0078	0.0144	0.0041	0.0053	0.0104	0.0022	0.0628	0.3225	0.0031	0.0046	0.0024	0.0123	0.0007
Alaska	+	0.0001	0.0006	0.0004	+	+	0.0033	+	0.0031	0.0015	+	0.0003	+
Arizona	0.1737	0.3229	0.2326	0.1465	0.0125	0.0026	0.0035	+	0.0031	0.0154	0.0012	0.0102	0.0001
Arkansas	0.0007	0.0012	0.0036	0.0033	0.0038	0.0085	0.0743	0.3140	0.0840	0.0040	0.0015	0.0097	0.0005
California	0.3213	0.5971	2.1362	1.7345	0.0089	0.0006	0.0906	0.0172	0.0449	0.0710	0.0039	0.0259	0.0005
Colorado	0.7310	1.3583	0.1780	0.1711	0.0507	0.0212	0.0210	+	0.0031	0.0507	0.0014	0.0148	0.0003
Connecticut	0.0002	0.0004	0.0148	0.0114	+	+	0.0108	+	0.0031	0.0029	0.0001	0.0015	+
Delaware	0.0002	0.0004	0.0039	0.0039	0.0002	0.0001	0.0031	0.0681	0.0031	0.0046	0.0001	0.0005	+
Florida	0.0040	0.0074	0.1001	0.0501	0.0003	0.0001	0.0414	0.0191	0.0031	0.0046	0.0017	0.0160	0.0004
Georgia	0.0057	0.0106	0.0486	0.0305	0.0111	0.0030	0.1042	0.4376	0.0031	0.0046	0.0025	0.0090	0.0006
Hawaii	0.0010	0.0019	0.0019	0.0023	0.0006	0.0002	0.0033	+	0.0031	0.0015	0.0003	0.0010	+
Idaho	0.1534	0.2845	0.7848	0.6894	0.0021	0.0008	0.0035	+	0.0031	0.0265	0.0005	0.0073	0.0003
Illinois	0.1017	0.1887	0.1418	0.0952	0.3919	0.0713	0.0168	0.0172	0.0031	0.0187	0.0010	0.0112	0.0003
Indiana	0.0711	0.1315	0.2426	0.1281	0.3354	0.0403	0.1232	0.0172	0.0478	0.0180	0.0014	0.0072	0.0003
Iowa	0.8372	1.5524	0.2943	0.3101	1.8140	0.1390	0.2330	0.0172	0.0031	0.0640	0.0017	0.0075	0.0003
Kansas	1.5100	2.8022	0.1780	0.1816	0.1754	0.0242	0.0031	+	0.0031	0.0230	0.0015	0.0127	0.0003
Kentucky	0.0064	0.0119	0.0297	0.0257	0.0268	0.0047	0.0229	0.0995	0.0031	0.0152	0.0029	0.0228	0.0008
Louisiana	0.0038	0.0071	0.0062	0.0036	0.0001	+	0.0112	0.0172	0.0031	0.0040	0.0006	0.0083	0.0003
Maine	0.0007	0.0013	0.0240	0.0180	0.0001	0.0001	0.0129	+	0.0031	0.0029	0.0002	0.0013	+
Maryland	0.0064	0.0119	0.0403	0.0321	0.0015	0.0003	0.0117	0.0977	0.0031	0.0046	0.0005	0.0040	0.0001
Massachusetts	0.0002	0.0005	0.0092	0.0066	0.0004	0.0001	0.0005	+	0.0031	0.0029	0.0002	0.0029	0.0001
Michigan	0.0981	0.1817	0.5678	0.3330	0.0905	0.0153	0.0547	0.0172	0.0031	0.0259	0.0008	0.0110	0.0003
Minnesota	0.1984	0.3680	0.6451	0.5568	0.6568	0.0801	0.0471	0.0146	0.1333	0.0492	0.0011	0.0099	0.0002
Mississippi	0.0077	0.0143	0.0057	0.0046	0.0291	0.0070	0.0397	0.2414	0.0031	0.0046	0.0009	0.0072	0.0005
Missouri	0.0342	0.0637	0.1082	0.0718	0.2076	0.0510	0.0403	0.0873	0.0507	0.0272	0.0029	0.0177	0.0008
Montana	0.0200	0.0371	0.0189	0.0173	0.0139	0.0031	0.0022	+	0.0031	0.0248	0.0004	0.0131	0.0002
Nebraska	1.6696	3.1011	0.0815	0.0315	0.2539	0.0548	0.0409	0.0172	0.0031	0.0253	0.0010	0.0082	0.0002
Nevada	0.0046	0.0085	0.0391	0.0231	0.0002	+	0.0031	+	0.0031	0.0077	0.0004	0.0023	+
New Hampshire	0.0002	0.0003	0.0109	0.0075	0.0001	+	0.0031	+	0.0031	0.0029	0.0001	0.0013	+
New Jersey	0.0003	0.0005	0.0056	0.0044	0.0005	0.0001	0.0031	+	0.0031	0.0046	0.0003	0.0038	0.0001
New Mexico	0.0168	0.0312	0.4155	0.2511	+	+	0.0035	+	0.0031	0.0110	0.0011	0.0068	0.0001
New York	0.0160	0.0297	0.4926	0.3598	0.0053	0.0008	0.0220	0.0172	0.0031	0.0236	0.0012	0.0107	0.0002
North Carolina	0.0053	0.0099	0.0267	0.0150	0.7058	0.1187	0.0790	0.2570	0.1043	0.0099	0.0029	0.0104	0.0006
North Dakota	0.0381	0.0708	0.0233	0.0192	0.0086	0.0048	0.0031	+	0.0031	0.0239	0.0001	0.0052	0.0001
Ohio	0.1130	0.2099	0.3585	0.2187	0.1735	0.0234	0.1293	0.0203	0.0159	0.0477	0.0021	0.0117	0.0004
Oklahoma	0.2406	0.4466	0.0627	0.0434	0.1695	0.0557	0.0178	0.0681	0.0031	0.0229	0.0037	0.0204	0.0009
Oregon	0.0456	0.0845	0.1379	0.1400	0.0005	0.0002	0.0109	0.0172	0.0031	0.0249	0.0011	0.0098	0.0003
Pennsylvania	0.0480	0.0891	0.3982	0.3258	0.0975	0.0138	0.1075	0.0496	0.0203	0.0339	0.0018	0.0135	0.0006
Rhode Island	+	0.0001	0.0008	0.0005	+	+	0.0031	+	0.0031	0.0029	+	0.0006	+
South Carolina	0.0023	0.0042	0.0080	0.0043	0.0234	0.0013	0.0252	0.0716	0.0348	0.0046	0.0013	0.0052	0.0003

South Dakota	0.2145	0.3967	0.1300	0.0711	0.1031	0.0248	0.0101	+	0.0133	0.0935	0.0003	0.0080	0.0001
Tennessee	0.0059	0.0109	0.0209	0.0185	0.0126	0.0019	0.0097	0.0539	0.0031	0.0133	0.0039	0.0153	0.0012
Texas	1.8540	3.4433	0.5287	0.4487	0.0751	0.0120	0.0919	0.1936	0.0031	0.0739	0.0337	0.0570	0.0039
Utah	0.0163	0.0303	0.1216	0.1203	0.0584	0.0113	0.0188	+	0.0119	0.0336	0.0005	0.0066	0.0001
Vermont	0.0007	0.0014	0.1029	0.0617	0.0001	+	0.0008	+	0.0031	0.0029	0.0002	0.0017	0.0001
Virginia	0.0143	0.0266	0.0432	0.0260	0.0212	0.0007	0.0142	0.0773	0.0493	0.0320	0.0019	0.0112	0.0004
Washington	0.1478	0.2748	0.3294	0.2340	0.0014	0.0005	0.0298	0.0172	0.0031	0.0065	0.0010	0.0117	0.0002
West Virginia	0.0032	0.0059	0.0069	0.0056	0.0002	0.0001	0.0071	0.0302	0.0096	0.0126	0.0008	0.0049	0.0002
Wisconsin	0.1539	0.2855	1.7964	1.3101	0.0222	0.0059	0.0242	0.0166	0.0031	0.0276	0.0017	0.0156	0.0004
Wyoming	0.0462	0.0860	0.0075	0.0094	0.0041	0.0048	0.0001	+	0.0031	0.0408	0.0002	0.0111	0.0001

+ Emission estimate is less than 0.00005 Gg.

3.12. Methodology for Estimating N_2O Emissions and Soil Organic C Stock Changes from Agricultural Soil Management (Cropland and Grassland)

Nitrous oxide (N_2O) emissions from agricultural soils result from the interaction of the natural processes of denitrification and nitrification with management practices that add or release mineral nitrogen (N) in the soil profile. Emissions can occur directly in the soil where the N is made available or can be transported to another location following volatilization, leaching, or runoff, and then converted into N_2O. Management also influences soil organic C stocks in agricultural soils by modifying the natural processes of photosynthesis (i.e., crop and forage production) and microbial decomposition. This sub-annex describes the methodologies used to calculate N_2O emissions from agricultural soil management[74] and annual carbon (C) stock changes from mineral and organic soils classified as *Cropland Remaining Cropland*, *Land Converted to Cropland*, *Grassland Remaining Grassland*, and *Land Converted to Grassland.*[75] This annex provides the underlying methodologies for both N_2O emissions from agricultural soil management and soil organic C stock change from mineral and organic soils. There is considerable overlap in the methods and data sets used for these source categories, and the majority of emission are estimated with the same inventory analysis using the DAYCENT biogeochemical simulation model.

A combination of Tier 1, 2 and 3 approaches is used to estimate direct and indirect N_2O emissions, in addition to C stock changes in agricultural soils. More specifically, the methodologies used to estimate soil N_2O emissions include:

1) Tier 3 method to estimate direct emissions from mineral soils for alfalfa hay, barley, corn, cotton, dry beans, grass hay, grass-clover hay, oats, onions, peanuts, potatoes, rice, sorghum, soybeans, sugar beets, sunflowers, tomatoes, and wheat, as well as non-federal grasslands and land use change between cropland (with the crops listed above) and grassland, using the DAYCENT biogeochemical simulation model;
2) Tier 1 method to estimate direct N_2O emissions from mineral soils for some vegetables, tobacco, perennial/horticultural crops (i.e., all crops that are not listed in Item 1 above), and crops that are rotated with these crops, in addition to federal grasslands (i.e., not simulated by DAYCENT);
3) Tier 1 method to estimate direct N_2O emissions due to drainage of organic soils in croplands and grasslands;
4) A combination of the Tier 3 and 1 methods to estimate indirect N_2O emissions associated with management of Tier 3 crops (i.e., simulated by DAYCENT; see list above), non-federal grasslands and land use change between cropland and grassland; and
5) Tier 1 method to estimate indirect emissions from some vegetables, tobacco, perennial/horticultural crops, and crops that are rotated with these crops, in addition to federal grasslands and all other land uses.

The methodologies used to estimate soil organic C stock changes include:

1) Tier 3 method to estimate soil organic C stock changes in mineral soils for crops (See crop list in Item 1 for N_2O emissions), non-federal grasslands and land use change between grasslands and croplands, using the DAYCENT biogeochemical simulation model;
2) Tier 2 methods with country-specific stock change factors for estimating mineral soil organic C stock changes for crop rotations and land use changes to cropland and grassland (other than the conversions between cropland and grassland) that were not simulated with DAYCENT;
3) Tier 2 methods with country-specific emission factors for estimating losses of C from organic soils that are partly or completely drained for agricultural production; and
4) Tier 2 methods for estimating additional changes in mineral soil C stocks due to sewage sludge additions to soils and enrollment changes in the Conservation Reserve Program (CRP) after 2007.

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[74] Direct Soil N_2O methods from forestlands and settlements are described elsewhere in Forestland Remaining Forestland and Settlements Remaining Settlements.

[75] Soil C stock change methods for forestland are described elsewhere in the Forestland Remaining Forestland section.

As described above, the Inventory uses a Tier 3 approach to estimate direct soil N_2O emissions and C stock changes for the majority of agricultural lands. This approach has several advantages over the IPCC Tier 1 or 2 approaches:

- It utilizes actual weather data at sub-county scales, rather than a broad climate region classification, enabling quantification of inter-annual variability in N_2O emissions and C stock changes at finer spatial scales;
- The model uses a more detailed characterization of spatially-mapped soil properties that influence soil C and N dynamics, as opposed to the broad soil taxonomic classifications of the IPCC methodology;
- The simulation approach provides a more detailed representation of management influences and their interactions than are represented by a discrete factor-based approach in the Tier 1 and 2 methods; and
- Soil N_2O emissions and C stock changes are estimated on a more continuous, daily basis as a function of the interaction of climate, soil, and land management, compared with the linear rate changes that are estimated with the Tier 1 and 2 methods.

The DAYCENT process-based simulation model (daily time-step version of the Century model) has been selected for the Tier 3 approach based on several criteria:

- The model has been developed in the United States and extensively tested and verified for U.S. conditions (e.g., Parton et al. 1987, 1993). In addition, the model has been widely used by researchers and agencies in many other parts of the world for simulating soil C dynamics at local, regional and national scales (e.g., Brazil, Canada, India, Jordan, Kenya, Mexico), and soil N_2O emissions (e.g., Canada, China, Ireland, New Zealand) (Abdalla et al. 2010, Li et al., Smith et al. 2008, Stehfest and Muller 2004) .
- The model is capable of simulating cropland, grassland, forest, and savanna ecosystems, and land-use transitions between these different land uses. It is, thus, well suited to model land-use change effects.
- The model is designed to simulate management practices that influence soil C dynamics and direct N_2O emissions, with the exception of cultivated organic soils; cobbly, gravelly, or shaley soils; and a few crops that have not been parameterized for DAYCENT simulations (e.g., some vegetables, tobacco, perennial/horticultural crops, and crops that are rotated with these crops). For these latter cases, an IPCC Tier 2 method has been used for soil C stock changes and IPCC Tier 1 method for N_2O emissions. The model can also be used estimate the amount of N leaching and runoff, as well as volatilization of N, which is subject to indirect N_2O emissions.
- Much of the data needed for the model is available from existing national databases. The exceptions are CRP enrollment after 2007, management of federal grasslands, and sewage sludge amendments to soils, which are not known at a sufficient resolution to use the Tier 3 model. Soil N_2O emissions and C stock changes associated with these practices are addressed with a Tier 1 and 2 method, respectively.

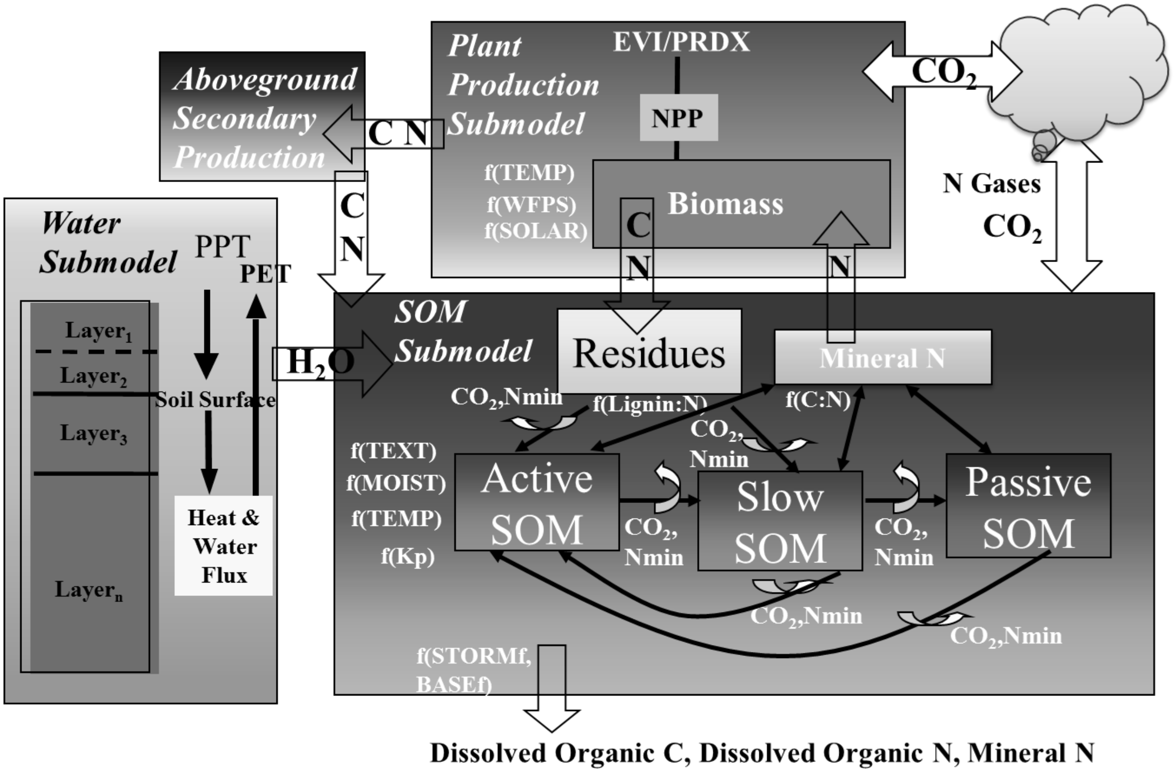
Overall, the Tier 3 approach is used to estimate approximately 82 to 88 percent of direct soil N_2O emissions and 85 to 87 percent of the land area associated with estimation of soil organic C stock changes under agricultural management in the United States.

Tier 3 Method Description and Model Evaluation

The DAYCENT biogeochemical model (Parton et al. 1998; Del Grosso et al. 2001, 2011) simulates biogeochemical C and N fluxes between the atmosphere, vegetation, and soil; and provides a more complete estimation of soil C stock changes and N_2O emissions than IPCC Tier 1/2 methods by more thoroughly accounting for the influence of environmental conditions including soil characteristics and weather patterns, specific crop and forage qualities that influence the C and N cycle, and management practices. The DAYCENT model utilizes the soil C modeling framework developed in the Century model (Parton et al. 1987, 1988, 1994; Metherell et al. 1993), but has been refined to simulate dynamics at a daily time-step. Carbon and N dynamics are linked in plant-soil systems through biogeochemical processes of microbial decomposition and plant production (McGill and Cole 1981). Coupling the two source categories (i.e., agricultural soil C and N_2O) in a single inventory analysis ensures that there is a consistent treatment of the processes and interactions between C and N cycling in soils. For example, plant growth is controlled by nutrient availability, water, and temperature stress. Plant growth along with the residue management determines the C inputs to soils, which influence the C stock changes, and removal of mineral N from the soil with plant growth influences the amount of N that can be converted into N_2O. Nutrient supply is a function of external nutrient additions as well as litter and soil organic matter (SOM) decomposition rates, and increasing decomposition can lead to a reduction in soil organic C stocks due to microbial respiration, and greater N_2O emissions by enhancing mineral N availability in soils.

Key processes simulated by DAYCENT include plant production, organic matter formation and decomposition, soil water and temperature regimes by layer, in addition to nitrification and denitrification processes (Figure A-7). The plant-growth submodel simulates C assimilation through photosynthesis; N uptake; dry matter production; partitioning of C within the crop or forage; senescence; and mortality. The primary function of the growth submodel is to estimate the amount, type, and timing of organic matter inputs to soil, and to represent the influence of the plant on soil water, temperature, and N balance. Yield and removal of harvested biomass are also simulated. Separate submodels are designed to simulate herbaceous plants (i.e., agricultural crops and grasses) and woody vegetation (i.e., trees and scrub). Maximum daily net primary production (NPP) is estimated using the NASA-CASA production algorithm (Potter et al.1993, 2007) and MODIS Enhanced Vegetation Index (EVI) products, MOD13Q1 and MYD13Q1, or an approximation of EVI data derived from the MODIS products (Gurung et al. 2009). The NASA-CASA production algorithm is only used in the central United States for the following major crops: corn, soybeans, sorghum, cotton and wheat.[76] Other regions and crops are simulated with a single value for the maximum daily net primary production (NPP), instead of the more dynamic NASA-CASA algorithm. The maximum daily NPP rate is modified by air temperature and available water to capture temperature and moisture stress. If the NASA-CASA algorithm is not used in the simulation, then production is further subject to nutrient limitations (i.e., nitrogen). Model evaluation has shown that the NASA-CASA algorithm improves the precision of NPP estimates using the EVI products to inform the production model. The r^2 is 83 percent for the NASA-CASA algorithm and 64 percent for the single parameter value approach).

Figure A-7: DAYCENT Model Flow Diagram



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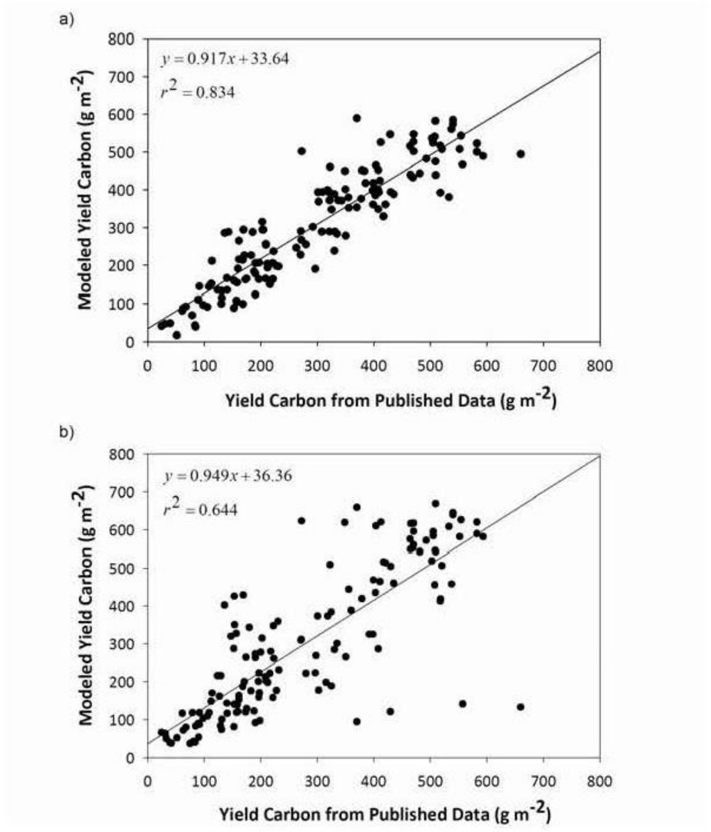
[76] It is a planned improvement to estimate NPP for additional crops and grass forage with the NASA-CASA method in the future.

Figure A-8: Modeled versus measured net primary production (g C m^{-2})



Part a) presents results of the NASA-CASA algorithm (r^2 = 83%) and part b) presents the results of a single parameter value for maximum net primary production (r^2 = 64%).

The soil-water balance submodel calculates water balance components and changes in soil water availability, which influences both plant growth and decomposition/nutrient cycling processes. The moisture content of soils are simulated through a multi-layer profile based on precipitation, snow accumulation and melting, interception, soil and canopy evaporation, transpiration, soil water movement, runoff, and drainage.

Dynamics of soil organic C and N (Figure A-7) are simulated for the surface and belowground litter pools and soil organic matter in the top 20 cm of the soil profile; mineral N dynamics are simulated through the whole soil profile. Organic C and N stocks are represented by two plant litter pools (metabolic and structural) and three soil organic matter (SOM) pools (active, slow, and passive). The metabolic litter pool represents the easily decomposable constituents of plant residues, while the structural litter pool is composed of more recalcitrant, ligno-cellulose plant materials. The three SOM pools represent a gradient in decomposability, from active SOM (representing microbial biomass and associated metabolites) having a rapid turnover (months to years), to passive SOM (representing highly processed, humified, condensed decomposition products), which is highly recalcitrant, with mean residence times on the order of several hundred years. The slow pool represents decomposition products of intermediate stability, having a mean residence time on the order of decades and is the fraction that tends to change the most in response to changes in land use and management. Soil texture influences turnover rates of the slow and passive pools. The clay and silt-sized mineral fraction of the soil provides physical protection from microbial decomposition, leading to enhanced SOM stabilization in finely textured soils. Soil temperature and moisture, tillage disturbance, aeration, and other factors influence decomposition and loss of C from the soil organic matter pools.

Soil mineral N dynamics are modeled based on N inputs from fertilizer inputs (synthetic and organic), residue N inputs, soil organic matter mineralization, symbiotic and asymbiotic N fixation. Mineral N is available for plant and microbial uptake, and is largely controlled by the specified stoichiometric limits for these organisms (i.e., C:N ratios). Mineral and organic N losses are simulated with leaching and runoff, and nitrogen can be volatilized and lost from the soil during a variety of processes including nitrification and denitrification. N_2O emissions from denitrification are a function of soil NO_3^- concentration, water filled pore space (WFPS), heterotrophic (i.e., microbial) respiration, and texture. Nitrification is controlled by soil ammonium (NH_4^+) concentration, water filled pore space, temperature, and pH (See Box 2 for more information).

The final main component of the model is the management submodel, which includes options for specifying crop type, crop sequence (e.g., rotation), tillage, fertilization, organic matter addition (e.g., manure amendments), harvest (with variable residue removal), drainage, irrigation, burning, and grazing intensity. An input "schedule" file is used to simulate the timing of management activities and temporal trends; schedules can be organized into discrete time blocks to define a repeated sequence of events (e.g., a crop rotation or a frequency of disturbance such as a burning cycle for perennial grassland). Management options can be specified for any day of a year within a scheduling block, where management codes point to operation-specific parameter files (referred to as *.100 files), which contain the information used to simulate management effects with the model algorithms. User-specified management activities can be defined by adding to or editing the contents of the *.100 files. Additional details of the model formulation are given in Parton et al. (1987, 1988, 1994, 1998), Del Grosso et al. (2001, 2011) and Metherell et al. (1993), and archived copies of the model source code are available.

[BEGIN TEXT BOX]

Box 2. DAYCENT Model Simulation of Nitrification and Denitrification

The DAYCENT model simulates the two biogeochemical processes, nitrification and denitrification, that result in N_2O emissions from soils (Del Grosso et al. 2000, Parton et al. 2001). Nitrification is calculated for the top 15 cm of soil, where nitrification mostly occurs, while denitrification is calculated for the entire soil profile accounting for denitrification near the surface and subsurface as nitrate leaches through the profile. The equations and key parameters controlling N_2O emissions from nitrification and denitrification are described below.

Nitrification is controlled by soil ammonium (NH_4^+) concentration, WFPS, temperature (t), and pH according to the following equation:

$$\text{Nit} = NH_4 \times K_{max} \times F(t) \times F(WFPS) \times F(pH)$$

where,

Nit = the soil nitrification rate (g N/m^2/day)
NH_4 = the model-derived soil ammonium concentration (g N/m^2)
K_{max} = the maximum fraction of NH_4^+ nitrified (K_{max} = 0.10/day)
F(t) = the effect of soil temperature on nitrification (Figure A-9a)
F(WFPS) = the effect of soil water content and soil texture on nitrification (Figure A-9b)
F(pH) = the effect of soil pH on nitrification (Figure A-9c)

The current parameterization used in the model assumes that 1.2 percent of nitrified N is converted to N_2O.

The model assumes that denitrification rates are controlled by the availability of soil NO_3^- (electron acceptor), labile C compounds (electron donor) and oxygen (competing electron acceptor). Heterotrophic soil respiration is used as a proxy for labile C availability, while oxygen availability is a function of soil physical properties that influence gas diffusivity, soil WFPS, and oxygen demand. The model selects the minimum of the NO_3^- and CO_2 functions to establish a maximum potential denitrification rate. These rates vary for particular levels of electron acceptor and C substrate, and account for limitations of oxygen availability to estimate daily denitrification rates according to the following equation:

$$\text{Den} = \min[F(CO_2), F(NO_3)] \times F(WFPS)$$

where,

Den = the soil denitrification rate (μg N/g soil/day)

$F(CO_2)$ = a function relating N gas flux to soil respiration (Figure A-10a)
$F(NO_3)$ = a function relating N gas flux to nitrate levels (Figure A-10b)
F(WFPS) = a dimensionless multiplier (Figure A-10c).

The x inflection point of F(WFPS) is a function of respiration and soil gas diffusivity at field capacity (D_{FC}):

$$x \text{ inflection} = 0.90 - M(CO_2)$$

where,

M = a multiplier that is a function of D_{FC}. In technical terms, the inflection point is the domain where either F(WFPS) is not differentiable or its derivative is 0. In this case, the inflection point can be interpreted as the WFPS value at which denitrification reaches half of its maximum rate.

Respiration has a much stronger effect on the water curve in clay soils with low D_{FC} than in loam or sandy soils with high D_{FC} (Figure A-10c). The model assumes that microsites in fine-textured soils can become anaerobic at relatively low water contents when oxygen demand is high.

After calculating total N gas flux, the ratio of N_2/N_2O is estimated so that total N gas emissions can be partitioned between N_2O and N_2:

$$R_{N2/N2O} = F_r(NO_3/CO_2) \times F_r(WFPS).$$

where,

$R_{N2/N2O}$ = the ratio of N_2/N_2O
$F_r(NO_3/CO_2)$ = a function estimating the impact of the availability of electron donor relative to substrate
$F_r(WFPS)$ = a multiplier to account for the effect of soil water on $N_2:N_2O$.

For $F_r(NO_3/CO_2)$, as the ratio of electron donor to substrate increases, a higher portion of N gas is assumed to be in the form of N_2O. For $F_r(WFPS)$, as WFPS increases, a higher portion of N gas is assumed to be in the form of N_2.

[End Box]

Figure A-9: Effect of Soil Temperature, Water-Filled Pore Space, and pH on Nitrification Rates

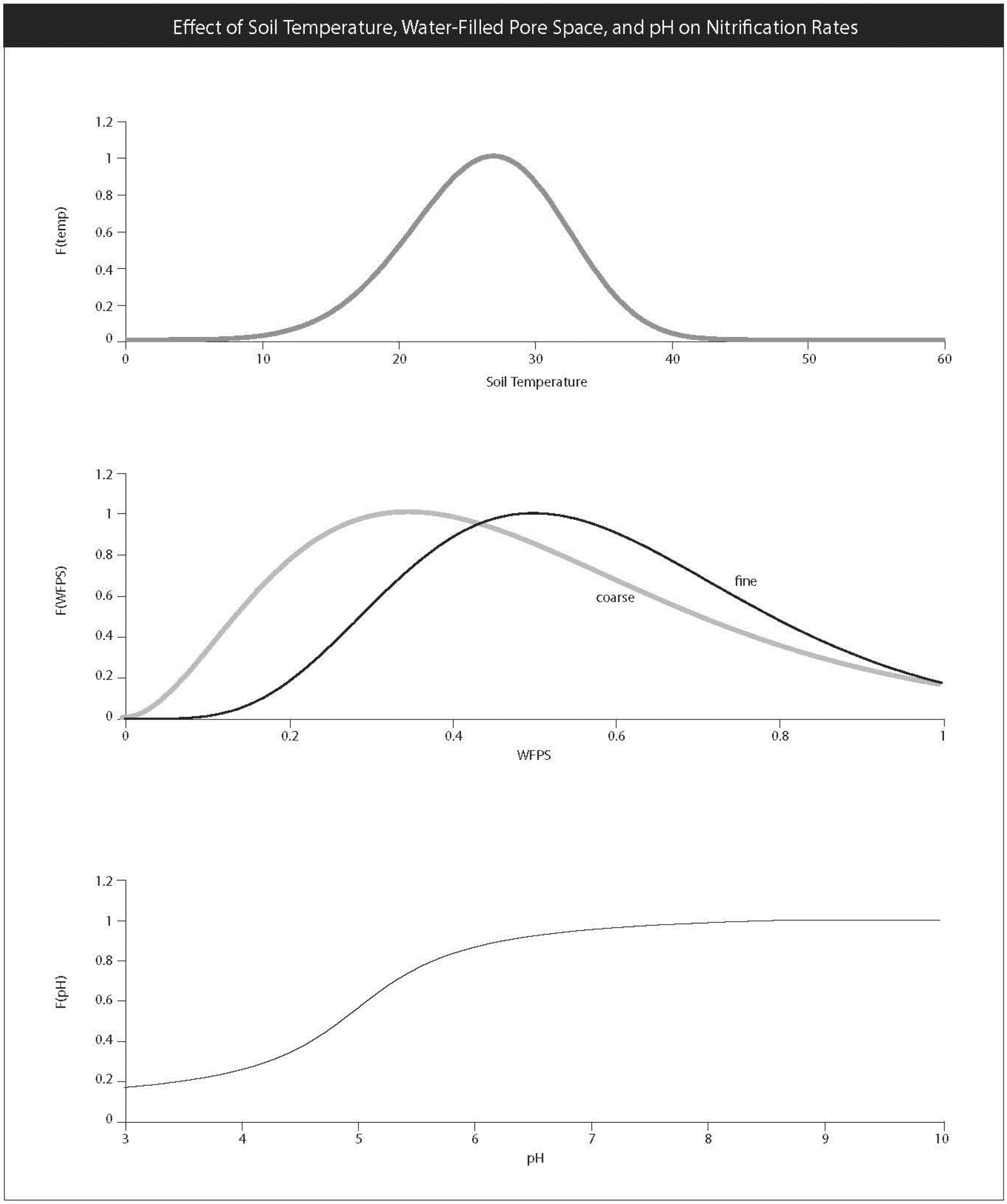
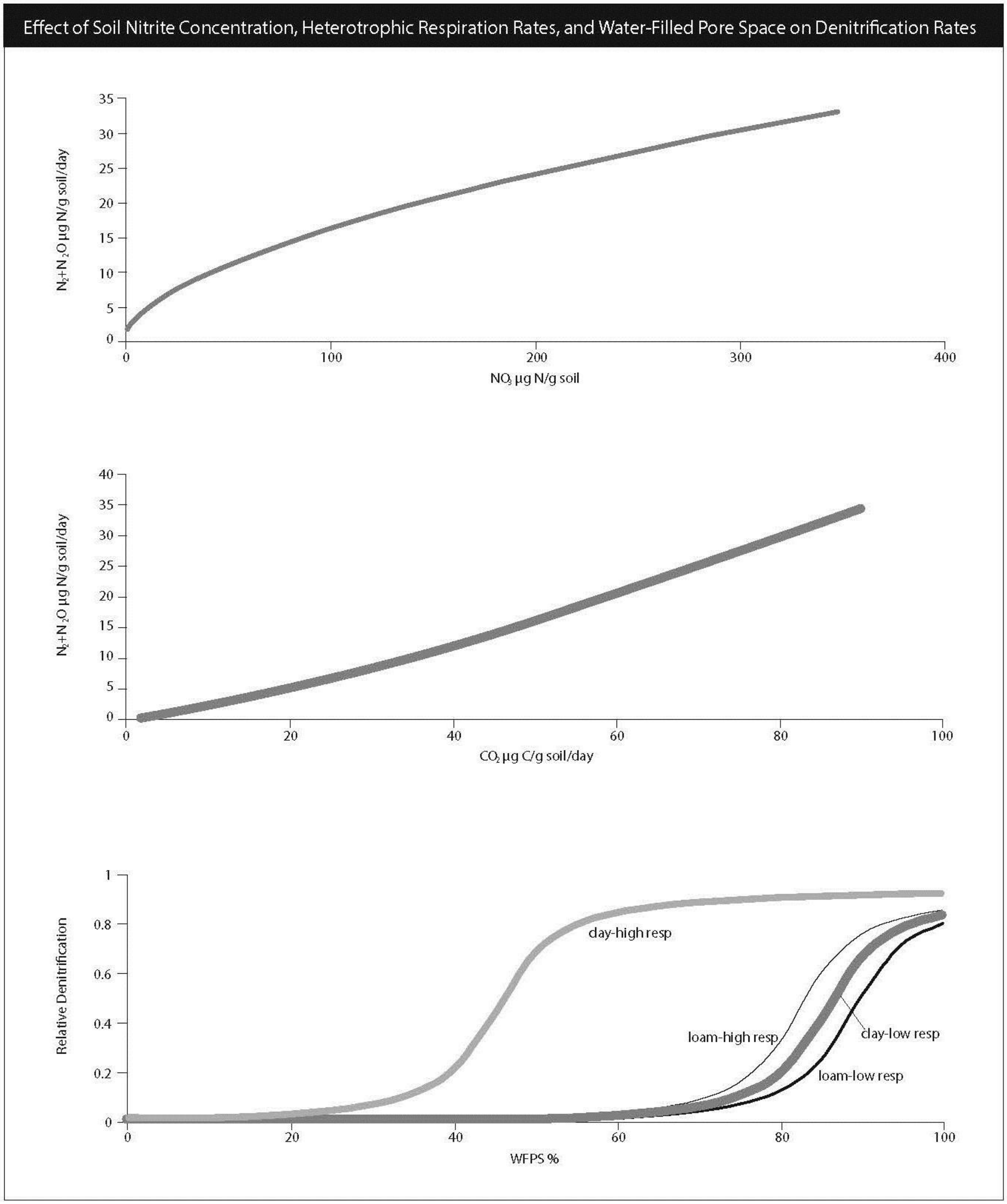


Figure A-10: Effect of Soil Nitrite Concentration, Heterotrophic Respiration Rates, and Water-Filled Pore Space on Denitrification Rates



Comparison of model results and plot level data show that DAYCENT reliably simulates soil organic matter levels (Ogle et al. 2007). The model was tested and shown to capture the general trends in C storage across approximately 870 field plots from 47 experimental sites (Figure A-11). Some biases and imprecision occur in predictions of soil organic C, which is reflected in the uncertainty associated with DAYCENT model results. Regardless, the Tier 3 approach has considerably less uncertainty than Tier 1 and 2 methods (Del Grosso et al., 201; Figure A-11).

Similarly, DAYCENT model results have been compared to trace gas N_2O fluxes for a number of native and managed systems (Del Grosso et al. 2001, 2005, 2010) (Figure A-12). In general, the model simulates accurate emissions, but some bias and imprecision does occur in predictions, which is reflected in the uncertainty associated with DAYCENT model results. Comparisons with measured data showed that DAYCENT estimated N_2O emissions more accurately and precisely than the IPCC Tier 1 methodology (See Figure 6-7: Comparison of Measured Emissions at Field Sites and Modeled Emissions Using the DAYCENT Simulation Model and IPCC Tier 1 Approach in the main chapter text). The linear regression of simulated vs. measured emissions for DAYCENT had higher r2 and a fitted line closer to a perfect 1:1 relationship between measured and modeled N_2O emissions (Del Grosso et al. 2005, 2008). This is not surprising, since DAYCENT includes site-specific factors (climate, soil properties, and previous management) that influence N_2O emissions. Furthermore, DAYCENT also simulated NO_3- leaching (root mean square error = 20 percent) more accurately than IPCC Tier 1 methodology (root mean square error = 69 percent) (Del Grosso et al. 2005). Volatilization of N gases that contribute to indirect soil N_2O emissions is the only component that has not been thoroughly tested, which is due to a lack of measurement data. Thus, the Tier 3 approach has reduced uncertainties in the agricultural soil C stock changes and N_2O emissions compared to using lower Tier methods.

Figure A-11: Comparisons of Results from DAYCENT Model and Measurements of Soil Organic C Stocks

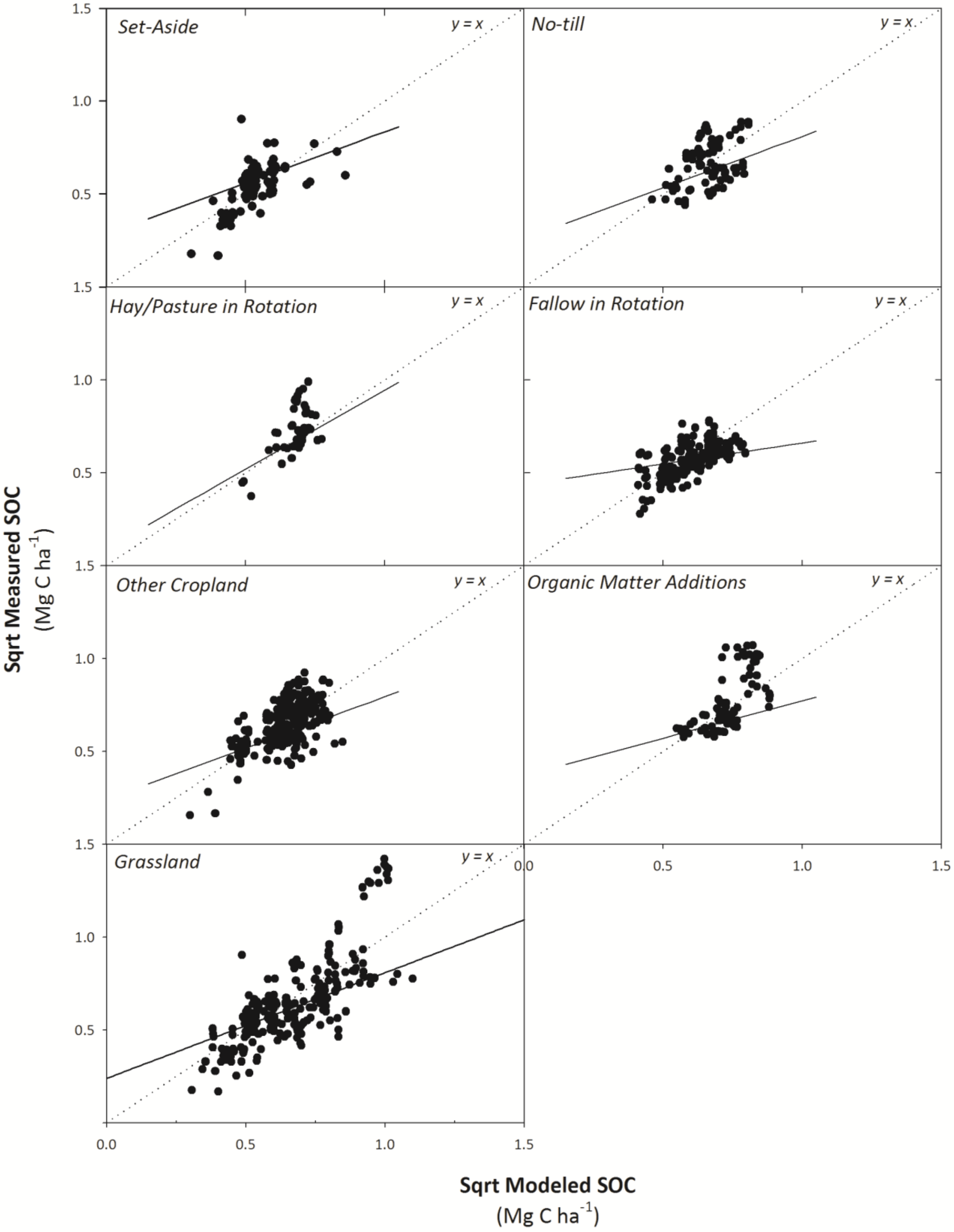
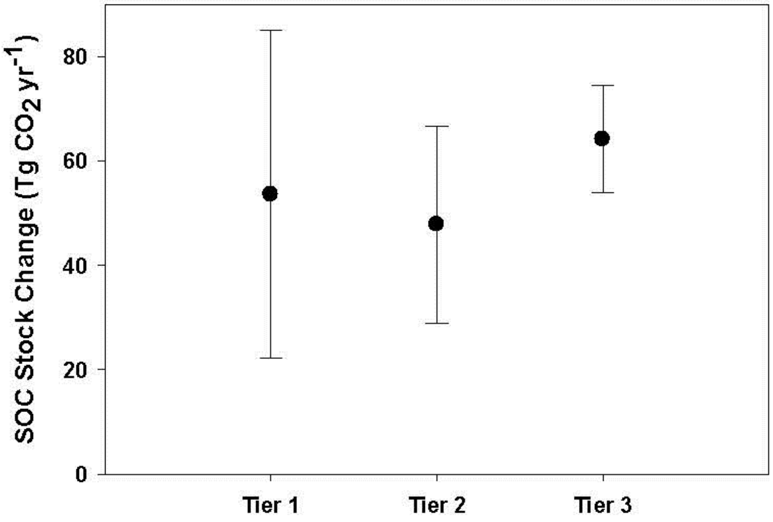


Figure A-12: Comparison of Estimated Soil Organic C Stock Changes and Uncertainties using Tier 1 (IPCC 2006), Tier 2 (Ogle et al. 2003, 2006) and Tier 3 Methods



Source: Tier 1 (IPCC 2007), Tier 2 (Ogle et al. 2003, 2006), Tier 3 (Ogle et al. 2010).

Inventory Compilation Steps

There are five steps in estimating soil organic C stock changes for *Cropland Remaining Cropland*, *Land Converted to Cropland*, *Grassland Remaining Grassland* and *Land Converted to Grassland*; direct N_2O emissions from cropland and grassland soils; and indirect N_2O emissions from volatilization, leaching, and runoff from all managed lands (i.e., croplands, grasslands, forest lands, and settlements). First, the activity data are derived from a combination of land-use, livestock, crop, and grassland management surveys, as well as expert knowledge. In the second, third, and fourth steps, soil organic C stock changes, direct and indirect N_2O emissions are estimated using DAYCENT and/or the Tier 1 and 2 methods. In the fifth step, total emissions are computed by summing all components separately for soil organic C stock changes and N_2O emissions. The remainder of this annex describes the methods underlying each step.

Step 1: Derive Activity Data

The following describes how the activity data are derived to estimate soil organic C stock changes, in addition to direct and indirect N_2O emissions. The activity data requirements include: (1) land base and history data, (2) crop-specific mineral N fertilizer rates,[77] (3) crop-specific manure amendment N rates and timing, (4) other N inputs, (5) tillage practices, (6) irrigation data, (7) Enhanced Vegetation Index (EVI), (8) daily weather data, and (9) edaphic characteristics.

Step 1a: Activity Data for the Agricultural Land Base and Histories

The U.S. Department of Agriculture's *National Resources Inventory* (NRI) (USDA-NRCS 2009) provides the basis for identifying the U.S. agricultural land base on non-federal lands, and classifying parcels into *Cropland Remaining Cropland*, *Land Converted to Cropland*, *Grassland Remaining Grassland*, and *Land Converted to Grassland*. Note that the Inventory does not include estimates of C stock changes and N_2O emissions for federal grasslands (with the exception of soil N_2O from PRP manure N, i.e., manure deposited directly onto pasture, range or paddock by grazing livestock) and a minor amount of croplands on federal lands, even though these areas are part

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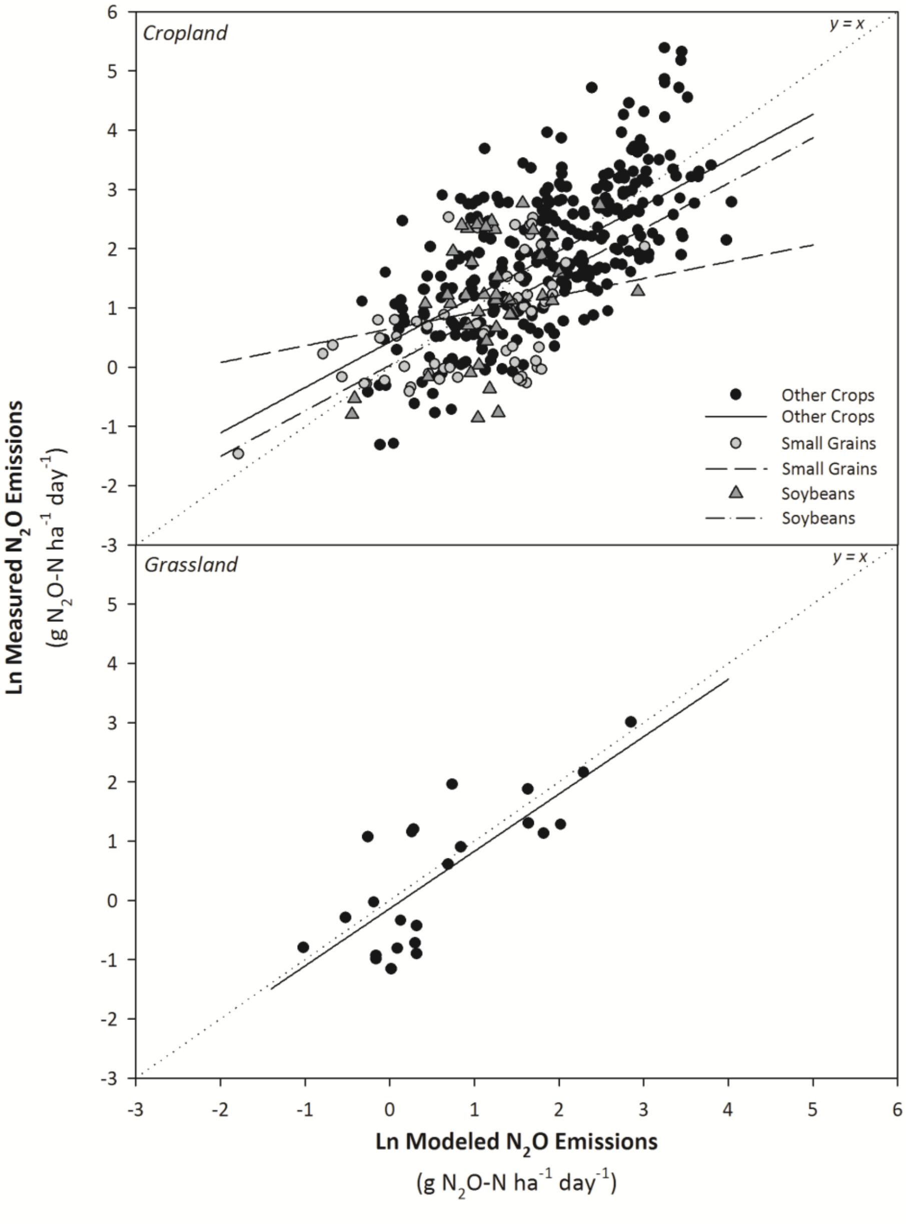
[77] No data are currently available at the national scale to distinguish the type of fertilizer applied or timing of applications rates. It is a planned improvement to address variation in these practices in future inventories.

of the managed land base for the United States. Methods are under development for estimating greenhouse gas emissions from soils on federal croplands and grasslands, and will be included in future inventories.

Figure A-13: Comparisons of Results from DAYCENT Model and Measurements of Soil Nitrous Oxide Emissions



The NRI has a stratified multi-stage sampling design, where primary sample units are stratified on the basis of county and township boundaries defined by the U.S. Public Land Survey (Nusser and Goebel 1997). Within a primary sample unit, typically a 160-acre (64.75 ha) square quarter-section, three sample points are selected according to a restricted randomization procedure. Each point in the survey is assigned an area weight (expansion factor) based on other known areas and land-use information (Nusser and Goebel 1997). In principle, the expansion factors represent the amount of area with the land use and land use change history that is the same as the point location. It is important to note that the NRI uses a sampling approach, and therefore there is some uncertainty associated with scaling the point data to a region or the country using the expansion factors. In general, those uncertainties decline at larger scales, such as states compared to smaller county units, because of a larger sample size. An extensive amount of soils, land-use, and land management data have been collected through the survey

(Nusser et al. 1998).[78] Primary sources for data include aerial photography and remote sensing imagery as well as field visits and county office records.

The annual NRI data product provides crop data for most years between 1979 and 2007, with the exception of 1983, 1988, and 1993. These years are gap-filled using an automated set of rules so that cropping sequences are filled with the most likely crop type given the historical cropping pattern at each NRI point location. Grassland data are reported on 5-year increments prior to 1998, but it is assumed that the land use is also grassland between the years of data collection (see Easter et al. 2008 for more information).

NRI points are included in the land base for the agricultural soil C and N_2O emissions inventories if they are identified as cropland or grassland[79] between 1990 and 2007 (Table A-216).[80] The NRI data are reconciled with the Forest Inventory and Analysis Dataset, and in this process, the time series for *Grassland Remaining Grassland* and *Land Converted to Grassland* is modified to account for differences in forest land area between the two national surveys (See Section 7.1 for more information on the U.S. land representation). Overall, 529,687 NRI survey points are included in the inventory.

For each year, land parcels are subdivided into *Cropland Remaining Cropland*, *Land Converted to Cropland*, *Grassland Remaining Grassland*, and *Land Converted to Grassland*. Land parcels under cropping management in a specific year are classified as *Cropland Remaining Cropland* if the parcel is cropland for at least 20 years. Similarly land parcels under grassland management in a specific year of the inventory are classified as *Grassland Remaining Grassland* if they are designated as grassland for at least 20 years.[81] Otherwise, land parcels are classified as *Land Converted to Cropland* or *Land Converted to Grassland* based on the most recent use in the inventory time period. Lands are retained in the land-use change categories (i.e., *Land Converted to Cropland* and *Land Converted to Grassland*) for 20 years as recommended by the IPCC guidelines (IPCC 2006). Lands converted into Cropland and Grassland are further subdivided into the specific land use conversions (e.g., Forest Land Converted to Cropland).

Table A-216: Total Land Areas for the Agricultural Soil C and N_2O Inventory, Subdivided by Land Use Categories (Million Hectares)

	Land Areas (million ha)										
Category	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**
Mineral Soils	**349.74**	**349.63**	**349.49**	**344.46**	**344.20**	**344.25**	**344.34**	**344.45**	**338.83**	**339.00**	**339.11**
Croplands											
Cropland Remaining Cropland	152.87	152.66	152.41	148.11	146.95	146.62	146.26	145.87	141.61	141.65	141.67
Grassland Converted to Cropland	12.82	13.12	13.38	15.19	16.75	16.97	17.31	17.46	18.08	17.64	17.25
Forest Converted to Cropland	0.62	0.62	0.62	1.24	1.24	1.24	1.24	1.24	0.41	0.41	0.41
Other Lands Converted to Cropland	0.11	0.11	0.11	0.25	0.25	0.25	0.25	0.25	0.13	0.13	0.13
Settlements Converted to Croplands	0.24	0.24	0.24	0.66	0.66	0.66	0.66	0.66	0.33	0.33	0.33
Wetlands Converted to Croplands	0.08	0.08	0.08	0.22	0.22	0.22	0.22	0.22	0.10	0.10	0.10
Grasslands											
Grasslands Remaining Grasslands	174.02	173.75	173.48	167.45	166.20	166.12	166.05	166.01	163.07	163.18	163.19
Croplands Converted to Grasslands	7.29	7.35	7.47	8.84	9.42	9.67	9.86	10.23	12.32	12.78	13.25
Forest Converted to Grasslands	1.15	1.15	1.15	1.72	1.72	1.72	1.72	1.72	1.79	1.79	1.79
Other Lands Converted to Grasslands	0.25	0.25	0.25	0.40	0.40	0.40	0.40	0.40	0.55	0.55	0.55
Settlements Converted to Grasslands	0.08	0.08	0.08	0.14	0.14	0.14	0.14	0.14	0.18	0.18	0.18
Wetlands Converted to Grasslands	0.22	0.22	0.22	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Organic Soils	**1.20**	**1.19**	**1.18**	**1.16**	**1.17**	**1.16**	**1.15**	**1.14**	**1.13**	**1.12**	**1.11**
Croplands											

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[78] In the current Inventory, NRI data only provide land-use and management statistics through 2007, but additional data will be incorporated in the future to extend the time series of land use and management data.

[79] Includes non-federal lands only, because federal lands are not classified into land uses as part of the NRI survey (i.e, they are only designated as federal lands).

[80] Land use for 2008 to 2012 is assumed to be the same as 2007, but will be updated after new NRI data are released.

[81] NRI points are classified according to land-use history records starting in 1982 when the NRI survey began, and consequently the classifications are based on less than 20 years from 1990 to 2001.

Cropland Remaining Cropland	0.59	0.59	0.58	0.56	0.55	0.55	0.54	0.54	0.52	0.52	0.52
Grassland Converted to Cropland	0.06	0.07	0.06	0.07	0.08	0.08	0.08	0.08	0.09	0.09	0.09
Forest Converted to Cropland	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Other Lands Converted to Cropland	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Settlements Converted to Croplands	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Wetlands Converted to Croplands	0.02	0.02	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01
Grasslands											
Grasslands Remaining Grasslands	0.44	0.43	0.43	0.42	0.41	0.40	0.39	0.38	0.37	0.36	0.36
Croplands Converted to Grasslands	0.05	0.05	0.05	0.05	0.06	0.07	0.06	0.07	0.08	0.08	0.08
Forest Converted to Grasslands	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Other Lands Converted to Grasslands	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Settlements Converted to Grasslands	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wetlands Converted to Grasslands	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02
Total	**350.94**	**350.82**	**350.67**	**345.62**	**345.37**	**345.41**	**345.49**	**345.58**	**339.96**	**340.12**	**340.23**

Category	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Mineral Soils	**339.09**	**339.12**	**339.23**	**338.85**	**338.35**	**337.90**	**337.53**	**337.30**	**337.06**	**336.83**	**336.60**	**336.37**
Croplands												
Cropland Remaining Cropland	141.68	142.22	144.37	143.42	143.68	143.96	144.57	144.57	144.57	144.57	144.57	144.57
Grassland Converted to Cropland	16.96	16.34	14.21	14.08	13.60	13.12	12.27	12.27	12.27	12.27	12.27	12.27
Forest Converted to Cropland	0.41	0.41	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Other Lands Converted to Cropland	0.13	0.13	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Settlements Converted to Croplands	0.33	0.33	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18
Wetlands Converted to Croplands	0.10	0.10	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Grasslands												
Grasslands Remaining Grasslands	163.03	163.56	165.91	165.79	165.53	165.47	165.86	165.69	165.51	165.33	165.15	164.97
Croplands Converted to Grasslands	13.67	13.25	12.57	13.38	13.38	13.18	12.66	12.60	12.55	12.50	12.44	12.39
Forest Converted to Grasslands	1.79	1.79	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07
Other Lands Converted to Grasslands	0.55	0.55	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39
Settlements Converted to Grasslands	0.18	0.18	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
Wetlands Converted to Grasslands	0.25	0.25	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Organic Soils	**1.10**	**1.09**	**1.06**	**1.05**	**1.05**	**1.04**	**1.04**	**1.03**	**1.03**	**1.03**	**1.03**	**1.03**
Croplands												
Cropland Remaining Cropland	0.52	0.52	0.54	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53
Grassland Converted to Cropland	0.11	0.10	0.10	0.09	0.09	0.09	0.08	0.08	0.08	0.08	0.08	0.08
Forest Converted to Cropland	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Lands Converted to Cropland	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Settlements Converted to Croplands	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Wetlands Converted to Croplands	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Grasslands												
Grasslands Remaining Grasslands	0.32	0.32	0.31	0.31	0.31	0.30	0.30	0.30	0.30	0.30	0.30	0.30
Croplands Converted to Grasslands	0.09	0.10	0.09	0.10	0.10	0.09	0.08	0.08	0.08	0.08	0.08	0.08
Forest Converted to Grasslands	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Lands Converted to Grasslands	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Settlements Converted to Grasslands	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wetlands Converted to Grasslands	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Total	**340.19**	**340.20**	**340.29**	**339.90**	**339.40**	**338.94**	**338.56**	**338.32**	**338.09**	**337.86**	**337.63**	**337.39**

Note: The area estimates are not consistent with the land representation chapter because the current Inventory does not cover all of the managed land, including grassland and cropland in Alaska, as well as grasslands and croplands on federal lands in the conterminous United States.

The Tier 3 method using the DAYCENT model is applied to estimate soil C stock changes and N_2O emissions for most of the NRI points that occur on mineral soils. Parcels of land that are not simulated with DAYCENT are allocated to the Tier 2 approach for estimating soil organic C stock change, and a Tier 1 method (IPCC 2006) to estimate soil N_2O emissions (Table A- 214) (Note: Tier 1 method for soil N_2O does not require land area data with the exception of emissions from drainage and cultivation of organic soils so in practice it is only the amount of N input to mineral soils that is addressed by the Tier 1 method and not the actual land area). The land base that is not simulated with DAYCENT includes (1) land parcels occurring on organic soils; (2) land parcels that include non-agricultural uses such as forest and federal lands in one or more years of the inventory; (3) land parcels on mineral soils that are very gravelly, cobbly, or shaley (i.e., classified as soils that have greater than 35 percent of soil volume comprised of gravel, cobbles, or shale); or (4) land parcels that are used to produce vegetables, perennial/horticultural crops, tobacco or rice, which are either grown continuously or in rotation with other crops. DAYCENT has not been fully tested or developed to simulate biogeochemical processes in soils used to produce some annual (e.g., tobacco), horticultural (e.g., flowers), or perennial (e.g., vineyards, orchards) crops and agricultural use of organic soils. In addition, DAYCENT has not been adequately tested for soils with a high gravel, cobble, or shale content.

Table A-217: Total Land Area Estimated with Tier 2 and 3 Inventory Approaches (Million Hectares)

	Land Areas (million ha)				
	Mineral			Organic	
Year	Tier 1/2	Tier 3	Total	Tier 1/2	**Total**
1990	31.78	317.96	349.74	1.20	**350.94**
1991	31.78	317.85	349.63	1.19	**350.82**
1992	31.78	317.71	349.49	1.18	**350.67**
1993	26.90	317.56	344.46	1.16	**345.62**
1994	26.90	317.30	344.20	1.17	**345.37**
1995	26.90	317.35	344.25	1.16	**345.41**
1996	26.90	317.44	344.34	1.15	**345.49**
1997	26.90	317.55	344.45	1.14	**345.58**
1998	21.50	317.33	338.83	1.13	**339.96**
1999	21.50	317.50	339.00	1.12	**340.12**
2000	21.50	317.61	339.11	1.11	**340.23**
2001	21.50	317.58	339.09	1.10	**340.19**
2002	21.50	317.61	339.12	1.09	**340.20**
2003	21.63	317.59	339.23	1.06	**340.29**
2004	21.63	317.21	338.85	1.05	**339.90**
2005	21.63	316.71	338.35	1.05	**339.40**
2006	21.63	316.27	337.90	1.04	**338.94**
2007	21.63	315.89	337.53	1.04	**338.56**
2008	21.63	315.66	337.30	1.03	**338.32**
2009	21.63	315.43	337.06	1.03	**338.09**
2010	21.63	315.20	336.83	1.03	**337.86**
2011	21.63	314.96	336.60	1.03	**337.63**
2012	21.63	314.73	336.37	1.03	**337.39**

NRI points on mineral soils are classified into specific crop rotations, continuous pasture/rangeland, and other non-agricultural uses for the Tier 2 inventory analysis based on the survey data (Table A-218). NRI points are assigned to IPCC input categories (low, medium, high, and high with organic amendments) according to the classification provided in IPCC (2006). In addition, NRI differentiates between improved and unimproved grassland, where improvements include irrigation and interseeding of legumes. In order to estimate uncertainties, probability distribution functions (PDFs) for the NRI land-use data are constructed as multivariate normal based on the total area estimates for each land-use/management category and associated covariance matrix. Through this approach, dependencies in land use are taken into account resulting from the likelihood that current use is correlated with past use. These dependencies occur because as some land use/management categories increase in area, the area of other land use/management categories will decline. The covariance matrix addresses these relationships.

Table A-218: Total Land Areas by Land-Use and Management System for the Tier 2 Mineral Soil Organic C Approach (Million Hectares)

	Land Areas (million ha)			
Land-Use/Management System	**1990-1992 (Tier 2)**	**1993-1997 (Tier 2)**	**1998-2002 (Tier 2)**	**2003-2007 (Tier 2)**
Cropland Systems	**17.20**	**15.16**	**15.04**	**13.50**
Aquaculture	0.00	0.00	0.01	0.01
Conservation Reserve Program	0.86	0.80	0.40	0.45
Continuous Hay	1.20	1.16	1.32	1.36
Continuous Hay with Legumes or Irrigation	0.29	0.27	0.31	0.29
Continuous Perennial or Horticultural Crops	0.71	0.59	0.51	0.41
Continuous Rice	0.00	0.00	0.00	0.00
Continuous Row Crops	2.96	2.31	2.55	2.50
Continuous Row Crops and Small Grains	2.01	1.57	1.37	1.29
Continuous Small Grains	0.66	0.57	0.53	0.44
Irrigated Crops	5.61	5.41	5.76	5.04
Low Residue Annual Crops (e.g., Tobacco or Cotton)	0.79	0.90	0.72	0.57
Miscellaneous Crop Rotations	0.00	0.01	0.00	0.00
Rice in Rotation with other crops	0.01	0.00	0.01	0.03
Row Crops and Small Grains in with Hay and/or Pasture	0.47	0.35	0.41	0.22
Row Crops and Small Grains with Fallow	0.05	0.04	0.04	0.04
Row Crops in Rotation with Hay and/or Pasture	0.28	0.30	0.35	0.20
Row Crops with Fallow	0.03	0.01	0.03	0.00
Small Grains in Rotation with Hay and/or Pasture	0.19	0.11	0.10	0.06
Small Grains with Fallow	0.47	0.29	0.18	0.21
Vegetable Crops	0.61	0.47	0.44	0.38
Grassland Systems	**10.63**	**7.51**	**8.53**	**8.72**
Rangeland	3.71	2.88	3.27	3.43
Continuous Pasture	6.84	4.56	5.17	5.16
Continuous Pasture with Legumes or Irrigation	0.08	0.07	0.10	0.13
CRP	0.00	0.00	0.00	0.00
Total	**27.83**	**22.67**	**23.57**	**22.22**

For the Tier 3 inventory estimates, the actual cropping and grassland histories are simulated with the DAYCENT model so it is not necessary to classify NRI points into management systems. Uncertainty in the areas associated with each management system is determined from the estimated sampling variance from the NRI survey (Nusser and Goebel 1997). See Step 2b for additional discussion.

Organic soils are also categorized into land-use systems based on drainage (IPCC 2006). Undrained soils are treated as having no loss of organic C or soil N_2O emissions. Drained soils are subdivided into those used for cultivated cropland, which are assumed to have high drainage and relatively large losses of C, and those used for managed pasture, which are assumed to have less drainage with smaller losses of C. N_2O emissions are assumed to be similar for both drained croplands and grasslands. Overall, the area of organic soils drained for cropland and grassland has remained relatively stable since 1990 (see Table A-219).

Table A-219: Total Land Areas for Drained Organic Soils By Land Management Category and Climate Region (Million Hectares)

	Land Areas (million ha)													
IPCC Land-Use Category for Organic Soils	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**
	Cold Temperate													
Cultivated Cropland (high drainage)	0.37	0.36	0.36	0.36	0.37	0.37	0.36	0.37	0.36	0.36	0.35	0.35	0.34	0.34
Managed Pasture (low drainage)	0.31	0.30	0.30	0.30	0.30	0.29	0.29	0.28	0.29	0.29	0.28	0.27	0.28	0.27
Undrained	0.05	0.05	0.05	0.04	0.03	0.03	0.04	0.03	0.03	0.03	0.04	0.03	0.03	0.02
Total	**0.72**	**0.72**	**0.71**	**0.70**	**0.70**	**0.69**	**0.69**	**0.68**	**0.68**	**0.67**	**0.67**	**0.65**	**0.64**	**0.63**
	Warm Temperate													
Cultivated Cropland (high drainage)	0.09	0.09	0.09	0.08	0.09	0.09	0.09	0.08	0.09	0.09	0.09	0.08	0.09	0.09
Managed Pasture (low drainage)	0.07	0.07	0.07	0.07	0.07	0.08	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Undrained	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.01	0.00	0.00	0.00
Total	**0.17**	**0.17**	**0.17**	**0.16**	**0.17**	**0.17**	**0.17**	**0.16**	**0.17**	**0.17**	**0.17**	**0.16**	**0.16**	**0.16**
	Tropical													

Cultivated Cropland (high drainage)	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.16	0.17	0.17	0.17	0.19	0.19	0.19
Managed Pasture (low drainage)	0.13	0.12	0.12	0.12	0.12	0.12	0.12	0.11	0.11	0.11	0.11	0.08	0.08	0.07
Undrained	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.01	0.00
Total	**0.30**	**0.30**	**0.30**	**0.30**	**0.30**	**0.29**	**0.29**	**0.28**	**0.28**	**0.28**	**0.28**	**0.28**	**0.28**	**0.26**

	Land Areas (million ha)								
IPCC Land-Use Category for Organic Soils	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
	Cold Temperate								
Cultivated Cropland (high drainage)	0.33	0.33	0.32	0.32	0.32	0.32	0.32	0.32	0.32
Managed Pasture (low drainage)	0.27	0.28	0.27	0.27	0.27	0.27	0.27	0.27	0.27
Undrained	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Total	**0.63**	**0.63**	**0.62**	**0.62**	**0.62**	**0.62**	**0.62**	**0.62**	**0.62**
	Warm Temperate								
Cultivated Cropland (high drainage)	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Managed Pasture (low drainage)	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Undrained	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	**0.17**	**0.17**	**0.16**	**0.16**	**0.16**	**0.16**	**0.16**	**0.16**	**0.16**
	Tropical								
Cultivated Cropland (high drainage)	0.19	0.18	0.19	0.18	0.18	0.18	0.18	0.18	0.18
Managed Pasture (low drainage)	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Undrained	0.00	0.01	0.00	0.01	0.01	0.01	0.01	0.01	0.01
Total	**0.26**	**0.26**	**0.26**	**0.26**	**0.26**	**0.26**	**0.26**	**0.26**	**0.26**

Step 1b: Obtain Management Activity Data for the Tier 3 Method to estimate Soil C Stock Changes and N_2O Emissions from Mineral Soils

Synthetic N Fertilizer Application: Data on N fertilizer rates are based primarily on the USDA–Economic Research Service Cropping Practices Survey (USDA-ERS 1997, 2011). In these surveys, data on inorganic N fertilization rates are collected for crops simulated by DAYCENT (barley, corn, cotton, dry beans, oats, onions, peanuts, potatoes, rice, sorghum, soybeans, sugar beets, sunflowers, tomatoes, and wheat) in the high production states and for a subset of low production states. These data are used to build a time series of fertilizer application rates for specific crops and states for the 1990 through 1999 time period and 2000 through 2012 time period. If only a single survey is available for a crop, as is the case with sorghum, the rates for the one survey are used for both time periods.

Mean fertilizer rates and standard deviations for irrigated and rainfed crops are produced for each state. If a state is not surveyed for a particular crop or if there are not enough data to produce a state-level estimate, then data are aggregated to USDA Farm Production Regions in order to estimate a mean and standard deviation for fertilization rates (Farm Production Regions are groups of states in the United States with similar agricultural commodities). If Farm Production Region data are not available, crop data are aggregated to the entire United States (all major states surveyed) to estimate a mean and standard deviation for a particular crop in a state lacking sufficient data. Standard deviations for fertilizer rates are used to construct probability distribution functions (PDFs) with log-normal densities in order to address uncertainties in application rates (see Step 2a for discussion of uncertainty methods). The survey summaries also present estimates for fraction of crop acres receiving fertilizer, and these fractions are used to determine if a crop is receiving fertilizer. Alfalfa hay and grass-clover hay are assumed to not be fertilized, but grass hay is fertilized according to rates from published farm enterprise budgets (NRIAI 2003). Total fertilizer application data are found in Table A- 220.

Simulations are conducted for the period prior to 1990 in order to initialize the DAYCENT model (see Step 2a), and crop-specific regional fertilizer rates prior to 1990 are based largely on extrapolation/interpolation of fertilizer rates from the years with available data. For crops in some states, little or no data are available, and, therefore, a geographic regional mean is used to simulate N fertilization rates (e.g., no data are available for the State of Alabama during the 1970s and 1980s for corn fertilization rates; therefore, mean values from the southeastern United States are used to simulate fertilization to corn fields in this state).

Managed Livestock Manure[82]*Amendments:* County-level manure addition estimates have been derived from manure N addition rates developed by the USDA Natural Resources Conservation Service (NRCS) (Edmonds et al. 2003). Working with the farm-level crop and animal data from the 1997 Census of Agriculture, USDA-NRCS has coupled estimates of manure N produced with estimates of manure N recoverability by animal waste management system to produce county-level rates of manure N application to cropland and pasture. Edmonds et al. (2003) defined a hierarchy that included 24 crops, permanent pasture, and cropland used as pasture. They estimated the area amended with manure and application rates in 1997 for both manure-producing farms and manure-receiving farms within a county and for two scenarios—before implementation of Comprehensive Nutrient Management Plans (baseline) and after implementation (Edmonds et al. 2003). The goal of nutrient management plans is to apply manure nutrients at a rate meeting plant demand, thus limiting leaching losses of nutrients to groundwater and waterways.

For DAYCENT simulations, the rates for manure-producing farms and manure-receiving farms have been area-weighted and combined to produce a single county-level estimate for the amount of land amended with manure and the manure N application rate for each crop in each county. The estimates were based on the assumption that Comprehensive Nutrient Management Plans have not been fully implemented. This is a conservative assumption because it allows for higher leaching rates due to some over-application of manure to soils. In order to address uncertainty in these data, uniform probability distributions are constructed based on the proportion of land receiving manure versus the amount not receiving manure for each crop type and pasture. For example, if 20 percent of land producing corn in a county is amended with manure, randomly drawing a value equal to or greater than 0 and less than 20 would lead to a simulation with a manure amendment, while drawing a value greater than or equal to 20 and less than 100 would lead to no amendment in the simulation (see Step 2a for further discussion of uncertainty methods).

Edmonds et al. (2003) only provides manure application rate data for 1997, but the amount of managed manure available for soil application changes annually, so the area amended with manure is adjusted relative to 1997 to account for all the manure available for application in other years. Specifically, the manure N available for application in other years is divided by the manure N available in 1997. If the ratio is greater than 1, there is more manure N available in that county relative to the amount in 1997, and so it is assumed a larger area is amended with manure. In contrast, ratios less than one imply less area is amended with manure because there is a lower amount available in the year compared to 1997. The amendment area in each county for 1997 is multiplied by the ratio to reflect the impact of manure N availability on the area amended. The amount of managed manure N available for application to soils is calculated by determining the populations of livestock that are on feedlots or otherwise housed, requiring collection and management of the manure, and the methods are described in the Manure Management section (Section 6.2) and annex (Annex 3.11). The total managed manure N applied to soils is found in Table A- 221.

To estimate C inputs associated with manure N application rates derived from Edmonds et al. (2003), carbon-nitrogen (C:N) ratios for livestock-specific manure types are adapted from the Agricultural Waste Management Field Handbook (USDA 1996), On-Farm Composting Handbook (NRAES 1992), and recoverability factors provided by Edmonds et al (2003). The C:N ratios are applied to county-level estimates of manure N excreted by animal type and management system to produce a weighted county average C:N ratio for manure amendments. The average C:N ratio is used to determine the associated C input for crop amendments derived from Edmonds et al. (2003).

To account for the common practice of reducing inorganic N fertilizer inputs when manure is added to a cropland soil, crop-specific reduction factors are derived from mineral fertilization data for land amended with manure versus land not amended with manure in the ERS 1995 Cropping Practices Survey (ERS 1997). Mineral N fertilization rates are reduced for crops receiving manure N based on a fraction of the amount of manure N applied, depending on the crop and whether it is irrigated or rainfed. The reduction factors are randomly selected from PDFs

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[82] For purposes of the inventory, total livestock manure is divided into two general categories: (1) managed manure, and (2) unmanaged manure. Managed manure includes manure that is stored in manure management systems such as drylots, pits and lagoons, as well as manure applied to soils through daily spread manure operations. Unmanaged manure encompasses all manure deposited on soils by animals on PRP.

with normal densities in order to address uncertainties in the dependence between manure amendments and mineral fertilizer application.

PRP Manure N: Another key source of N for grasslands is Pasture/Range/Paddock (PRP) manure N deposition (i.e., manure deposited by grazing livestock). The total amount of PRP manure N was estimated using methods described in the Manure Management section (Section 6.2) and annex (Annex 3.11). Nitrogen from PRP animal waste deposited on non-federal grasslands in a county was generated by multiplying the total PRP N (based on animal type and population data in a county) by the fraction of non-federal grassland area in the county. PRP manure N input rates for the Tier 3 DAYCENT simulations were estimated by dividing the total PRP manure N amount by the land area associated with non-federal grasslands in the county from the NRI survey data. The total PRP manure N added to soils is found in Table A- 221.

Residue N Inputs: Crop residue N, fixation by legumes, and N residue inputs from senesced grass litter are included as sources of N to the soil, and are estimated in the DAYCENT simulations as a function of vegetation type, weather, and soil properties. That is, while the model accounts for the contribution of N from crop residues to the soil profile and subsequent N_2O emissions, this source of mineral soil N is not activity data in the sense that it is not a model input. The simulated total N inputs of above- and below-ground residue N and fixed N that is not harvested and not burned (the DAYCENT simulations assumed that 3 percent of non-harvested above ground residues for crops are burned[83]) are provided in Table A-222.

Other N Inputs: Other N inputs are estimated within the DAYCENT simulation, and thus input data are not required, including mineralization from decomposition of soil organic matter and asymbiotic fixation of N from the atmosphere. Mineralization of soil organic matter will also include the effect of land use change on this process as recommended by the IPCC (2006). The influence of additional inputs of N are estimated in the simulations so that there is full accounting of all emissions from managed lands, as recommended by IPCC (2006). The simulated total N inputs from other sources are provided in Table A-222.

Tillage Practices: Tillage practices are estimated for each cropping system based on data from the Conservation Technology Information Center[84] (CTIC 2004). CTIC compiles data on cropland area under five tillage classes by major crop species and year for each county. Because the surveys involve county-level aggregate area, they do not fully characterize tillage practices as they are applied within a management sequence (e.g., crop rotation). This is particularly true for area estimates of cropland under no-till, which include a relatively high proportion of "intermittent" no-till, where no-till in one year may be followed by tillage in a subsequent year. For example, a common practice in maize-soybean rotations is to use tillage in the maize crop while no-till is used for soybean, such that no-till practices are not continuous in time. Estimates of the area under continuous no-till are provided by experts at CTIC to account for intermittent tillage activity and its impact on soil C (Towery 2001).

Tillage practices are grouped into 3 categories: full, reduced, and no-tillage. Full tillage is defined as multiple tillage operations every year, including significant soil inversion (e.g., plowing, deep disking) and low surface residue coverage. This definition corresponds to the intensive tillage and "reduced" tillage systems as defined by CTIC (2004). No-till is defined as not disturbing the soil except through the use of fertilizer and seed drills and where no-till is applied to all crops in the rotation. Reduced tillage made up the remainder of the cultivated area, including mulch tillage and ridge tillage as defined by CTIC and intermittent no-till. The specific tillage implements and applications used for different crops, rotations, and regions to represent the three tillage classes are derived from the 1995 Cropping Practices Survey by the Economic Research Service (ERS 1997).

Tillage data are further processed to construct probability distribution functions (PDFs). Transitions between tillage systems are based on observed county-level changes in the frequency distribution of the area under full, reduced, and no-till from the 1980s through 2004. Generally, the fraction of full tillage decreased during this time span, with concomitant increases in reduced till and no-till management. Transitions that are modeled and applied to NRI points occurring within a county are full tillage to reduced and no-till, and reduced tillage to no-till.

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[83] Another improvement is to reconcile the amount of crop residues burned with the Field Burning of Agricultural Residues source category (Section 6.5).

[84] National scale tillage data are no longer collected by CTIC, and a new data source will be needed, which is a planned improvement.

The remaining amount of cropland is assumed to have no change in tillage (e.g., full tillage remained in full tillage). Transition matrices are constructed from CTIC data to represent tillage changes for three time periods, 1980-1989, 1990-1999, 2000-2007. Areas in each of the three tillage classes—full till (FT), reduced till (RT), no-till (NT)—in 1989 (the first year the CTIC data are available) are used for the first time period, data from 1997 are used for the second time period, and data from 2004 are used for the last time period. Percentage areas of cropland in each county are calculated for each possible transition (e.g., FT→FT, FT→RT, FT→NT, RT→RT, RT→NT) to obtain a probability for each tillage transition at an NRI point. It is assumed that there are no transitions for NT→FT or NT→NT after accounting for NT systems that have intermittent tillage. Uniform probability distributions are established for each tillage scenario in the county. For example, a particular crop rotation had 80 percent chance of remaining in full tillage over the two decades, a 15 percent chance of a transition from full to reduced tillage and a 5 percent chance of a transition from full to no-till. The uniform distribution is subdivided into three segments with random draws in the Monte Carlo simulation (discussed in Step 2b) leading to full tillage over the entire time period if the value is greater than or equal to 0 and less than 80, a transition from full to reduced till if the random draw is equal to or greater than 80 and less than 95, or a transition from full to no-till if the draw is greater than or equal to 95. See step 2b for additional discussion of the uncertainty analysis.

Irrigation: NRI (USDA-NRCS 2009) differentiates between irrigated and non-irrigated land, but does not provide more detailed information on the type and intensity of irrigation. Hence, irrigation is modeled by assuming that applied water to field capacity with intervals between irrigation events where the soils drain to about 60 percent of field capacity.

Daily Weather Data: Daily maximum/minimum temperature and precipitation data are based on gridded weather data from the North America Regional Reanalysis Product (NARR) (Mesinger et al. 2006). It is necessary to use computer-generated weather data because weather station data do not exist near all NRI points, and moreover weather station data are for a point in space. The NARR product uses this information with interpolation algorithms to derive weather patterns for areas between these stations. NARR weather data are available for the U.S. from 1980 through 2007 at a 32 km resolution. Each NRI point is assigned the NARR weather data for the grid cell containing the point.

Enhanced Vegetation Index: The Enhanced Vegetation Index (EVI) from the MODIS vegetation products, (MOD13Q1 and MYD13Q1) is an input to DAYCENT for estimating net primary production using the NASA-CASA production algorithm (Potter et al. 1993, 2007). MODIS imagery is collected on a nominal 8 day-time frequency when combining the two products. A best approximation of the daily time series of EVI data is derived using a smoothing process based on the Savitzky-Golay Filter (Savitzky and Golay 1964) after pre-screening for outliers and for cloud-free, high quality data as identified in the MODIS data product quality layer. The NASA-CASA production algorithm is only used for the following crops: corn, soybeans, sorghum, cotton, wheat and other close-grown crops such as barley and oats.[85]

The MODIS EVI products have a 250 m spatial resolution, and some pixels in images have mixed land uses and crop types at this resolution, which is problematic for estimating NPP associated with a specific crop at a NRI point. Therefore, a threshold of 90 percent purity in an individual pixel is the cutoff for estimating NPP using the EVI data derived from the imagery (i.e., pixels with less than 90 percent purity for a crop are assumed to generate bias in the resulting NPP estimates). The USDA-NASS Crop Data Layer (CDL) (Johnson and Mueller 2010) is used to determine the purity levels of the EVI data. CDL data have a 30 to 58 m spatial resolution, depending on the year. The level of purity for individual pixels in the MODIS EVI products is determined by aggregating the crop cover data in CDL to the 250m resolution of the EVI data. In this step, the percent cover of individual crops is determined for the 250m EVI pixels. Pixels that did not meet a 90 percent purity level for any crop are eliminated from the dataset. CDL did not provide full coverage of crop maps for the conterminous United States until 2009 so it is not possible to evaluate purity for the entire cropland area prior to 2009.

The nearest pixel with at least 90 percent purity for a crop is assigned to the NRI point based on a 50 km buffer surrounding the survey location. EVI data are not assigned to a point if there are no pixels with at least 90 percent purity within the 50 km buffer. Furthermore, MODIS products do not provide any data on EVI prior to 2000, which preceded the launch of the MODIS sensor on the Aqua and Terra Satellites. It is good practice to apply a method consistently across a time series (IPCC 2006), and so a statistical model is used to estimate EVI for the

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[85] Additional crops and grassland will be used with the NASA-CASA method in the future, as a planned improvement.

inventory time series prior to 2000 and also to fill gaps if no pixel has at least 90 percent purity within the 50 km buffer due to purity limitations, lack of CDL data to evaluate purity, or low quality data (Gurung et al. 2009).

Soil Properties: Soil texture and natural drainage capacity (i.e., hydric vs. non-hydric soil characterization) are the main soil variables used as input to the DAYCENT model. Texture is one of the main controls on soil C turnover and stabilization in the DAYCENT model, which uses particle size fractions of sand (50-2,000 µm), silt (2-50 µm), and clay (< 2 µm) as inputs. Hydric condition specifies whether soils are poorly-drained, and hence prone to water-logging, or moderately to well-drained (non-hydric), in their native (pre-cultivation) condition.[86] Poorly drained soils can be subject to anaerobic (lack of oxygen) conditions if water inputs (precipitation and irrigation) exceed water losses from drainage and evapotranspiration. Depending on moisture conditions, hydric soils can range from being fully aerobic to completely anaerobic, varying over the year. Decomposition rates are modified according to a linear function that varies from 0.3 under completely anaerobic conditions to 1.0 under fully aerobic conditions (default parameters in DAYCENT).[87] Other soil characteristics needed in the simulation, such as field capacity and wilting-point water contents, are estimated from soil texture data using a standardized hydraulic properties calculator (Saxton et al. 1986). Soil input data are derived from Soil Survey Geographic Database (SSURGO) (Soil Survey Staff 2011). The data are based on field measurements collected as part of soil survey and mapping. Each NRI point is assigned the dominant soil component in the polygon containing the point from the SSURGO data product.

Step 1c: Obtain Additional Management Activity Data for the Tier 1 Method to estimate Soil N_2O Emissions from Mineral Soils

Synthetic N Fertilizer: A process-of-elimination approach is used to estimate synthetic N fertilizer additions to Tier 1 crops estimates. The total amount of fertilizer used on-farms has been estimated by the USGS from 1990-2001 on a county scale from fertilizer sales data (Ruddy et al. 2006). For 2002 through 2012, county-level fertilizer used on-farms is adjusted based on annual fluctuations in total U.S. fertilizer sales (AAPFCO 1995 through 2012). Fertilizer application data are available for crops and grasslands simulated by DAYCENT (discussed in Step 1a section for Tier 3 crops and non-federal grasslands). Thus, the amount of N applied to Tier 1 crops (i.e., not simulated by DAYCENT) is assumed to be the remainder of the fertilizer used on farms after subtracting the amount applied to Tier 3 crops and non-federal grasslands (i.e., simulated by DAYCENT). The differences are aggregated to the state level, and PDFs are derived based on uncertainties in the amount of N applied to Tier 3 crops and non-federal grasslands. Total fertilizer application to Tier 1 crops is found in Table A- 223.

Managed Livestock Manure and Other Organic Amendments: Manure N that is not applied to crops and grassland simulated by DAYCENT is assumed to be applied to other crops that are included in the Tier 1 method. Estimates of total national annual N additions from other commercial organic fertilizers are derived from organic fertilizer statistics (TVA 1991 through 1994; AAPFCO 1995 through 2011). Commercial organic fertilizers include dried blood, tankage, compost, and other; dried manure and sewage sludge that are used as commercial fertilizer are subtracted from totals to avoid double counting. The dried manure N is counted with the non-commercial manure applications, and sewage sludge is assumed to be applied only to grasslands. The organic fertilizer data, which are recorded in mass units of fertilizer, had to be converted to mass units of N by multiplying the consumption values by the average organic fertilizer N content of 0.5 percent (AAPFCO 2000a). The fertilizer consumption data are recorded in “fertilizer year” totals, (i.e., July to June), but are converted to calendar year totals. This is done by assuming that approximately 35 percent of fertilizer usage occurred from July to December and 65 percent from January to June (TVA 1992b). Values for July to December are not available for calendar year 2012 so a “least squares line” statistical extrapolation using the previous 5 years of data is used to arrive at an approximate value. PDFs are derived for the organic fertilizer applications assuming a default ±50 percent uncertainty. Annual consumption of other organic fertilizers is presented in Table A- 224. The fate of manure N is summarized in Table A- 221.

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[86] Artificial drainage (e.g., ditch- or tile-drainage) is simulated as a management variable.

[87] Hydric soils are primarily subject to anaerobic conditions outside the plant growing season (i.e., in the absence of active plant water uptake). Soils that are water-logged during much of the year are typically classified as organic soils (e.g., peat), which are not simulated with the DAYCENT model.

PRP Manure N: Soil N_2O emissions from PRP manure N deposited on federal grasslands is estimated with a Tier 1 method. PRP manure N data are derived using methods described in the Manure Management section (Section 6.2) and Annex 3.11. PRP N deposited on federal grasslands is calculated using a process of elimination approach. The amount of PRP N generated by DAYCENT model simulations of non-federal grasslands was subtracted from total PRP N and this difference was assumed to be applied to federal grasslands. The total PRP manure N added to soils is found in Table A- 221.

Sewage Sludge Amendments: Sewage sludge is generated from the treatment of raw sewage in public or private wastewater treatment works and is typically used as a soil amendment or is sent to waste disposal facilities such as landfills. In this Inventory, all sewage sludge that is amended to agricultural soils is assumed to be applied to grasslands. Estimates of the amounts of sewage sludge N applied to agricultural lands are derived from national data on sewage sludge generation, disposition, and N content. Total sewage sludge generation data for 1990-2011, in dry mass units, are obtained from AAPFCO (1990-2011). Values for 2012 were not available so a “least squares line” statistical extrapolation using the previous 5 years of data was used to arrive at an approximate value. The total sludge generation estimates are then converted to units of N by applying an average N content of 69 percent (AAPFCO 2000a), and disaggregated into use and disposal practices using historical data in EPA (1993) and NEBRA (2007). The use and disposal practices are agricultural land application, other land application, surface disposal, incineration, landfilling, ocean dumping (ended in 1992), and other disposal. The resulting estimates of sewage sludge N applied to agricultural land are used to estimate N_2O emissions from agricultural soil management; the estimates of sewage sludge N applied to other land and surface-disposed are used in estimating N_2O fluxes from soils in *Settlements Remaining Settlements* (see section 7.5 of the Land Use, Land-Use Change, and Forestry chapter). Sewage sludge disposal data are provided in Table A- 225).

Residue N Inputs: Soil N_2O emissions for residue N inputs from crops that are not simulated by DAYCENT are estimated with a Tier 1 method. Annual crop yield (metric tons per hectare) and area harvested (hectare) statistics for N-fixing crops, including bean and pulse crops, are taken from U.S. Department of Agriculture crop production reports (USDA 1994, 1998, 2003, 2005, 2006, 2007, 2008, 2009, 2010, 2011, 2012). Crop yield per hectare and area planted are multiplied to determine total crop yield for each crop, which is then converted to tons of dry matter product using the residue dry matter fractions shown in Table A- 226. Dry matter yield is then converted to tons of above- and below-ground biomass N. Above-ground biomass is calculated by using linear equations to estimate above-ground biomass given dry matter crop yields, and below-ground biomass is calculated by multiplying above-ground biomass by the below-to-above-ground biomass ratio. N inputs are estimated by multiplying above- and below-ground biomass by respective N concentrations. All ratios and equations used to calculate residue N inputs are from IPCC (2006) and Williams (2006). PDFs are derived assuming a ±50 percent uncertainty in the yield estimates (NASS does not provide uncertainty), along with uncertainties provided by the IPCC (2006) for dry matter fractions, above-ground residue, ratio of below-ground to above-ground biomass, and residue N fractions. The resulting annual biomass N inputs are presented in Table A-227.

Step 1d: Obtain Additional Management Activity Data for the Tier 2 Method to estimate Soil C Stock Changes in Mineral Soils

Tillage Practices: For the Tier 2 method that is used to estimate soil organic C stock changes, PDFs are constructed for the CTIC tillage data (CTIC 2004) as bivariate normal on a log-ratio scale to reflect negative dependence among tillage classes. This structure ensured that simulated tillage percentages are non-negative and summed to 100 percent. CTIC data do not differentiate between continuous and intermittent use of no-tillage, which is important for estimating SOC storage. Thus, regionally based estimates for continuous no-tillage (defined as 5 or more years of continuous use) are modified based on consultation with CTIC experts, as discussed in Step 1a (downward adjustment of total no-tillage area based on the amount of no-tillage that is rotated with more intensive tillage practices, Towery 2001).

Managed Livestock Manure Amendments: USDA provides information on the amount of land amended with manure for 1997 based on manure production data and field-scale surveys detailing application rates that had been collected in the *Census of Agriculture* (Edmonds et al. 2003). Similar to the DAYCENT model discussion in Step1b, the amount of land receiving manure is based on the estimates provided by Edmonds et al. (2003), as a proportion of crop and grassland amended with manure within individual climate regions. The resulting proportions are used to re-classify a portion of crop and grassland into a new management category. Specifically, a portion of medium input cropping systems is re-classified as high input, and a portion of the high input systems is re-classified as high input with amendment. In grassland systems, the estimated proportions for land amended with manure are used to re-classify a portion of nominally-managed grassland as improved, and a portion of improved grassland as improved with high input. These classification approaches are consistent with the IPCC inventory methodology (IPCC 2006). Uncertainties in the amount of land amended with manure are based on the sample variance at the climate region scale, assuming normal density PDFs (i.e., variance of the climate region estimates, which are derived from county-scale proportions).

Sewage Sludge Amendments: Sewage sludge is generated from the treatment of raw sewage in public or private wastewater treatment facilities and is typically used as a soil amendment or is sent for waste disposal to landfills. In this Inventory, all sewage sludge that is amended to agricultural soils is assumed to be applied to grasslands. See section on sewage sludge in Step 1c for more information about the methods used to derive sewage sludge N estimates, and the total amount of sewage sludge N is given in Table A- 225. Sewage sludge N is assumed to be applied at the assimilative capacity provided in Kellogg et al. (2000), which is the amount of nutrients taken up by a crop and removed at harvest, representing the recommended application rate for manure amendments. This capacity varies from year to year, because it is based on specific crop yields during the respective year (Kellogg et al. 2000). Total sewage sludge N available for application is divided by the assimilative capacity to estimate the total land area over which sewage sludge had been applied. The resulting estimates are used for the estimation of soil C stock change.

CRP Enrollment after 2007: The change in enrollment for the Conservation Reserve Program after 2007 is based on the amount of land under active contracts from 2008 through 2012 relative to 2007 (USDA-FSA 2012).

Wetland Reserve: Wetlands enrolled in the Conservation Reserve Program have been restored in the Northern Prairie Pothole Region through the Partners for Wildlife Program funded by the U.S. Fish and Wildlife Service. The area of restored wetlands is estimated from contract agreements (Euliss and Gleason 2002). While the contracts provide reasonable estimates of the amount of land restored in the region, they do not provide the information necessary to estimate uncertainty. Consequently, a ±50 percent range is used to construct the PDFs for the uncertainty analysis.

Table A- 220: Synthetic Fertilizer N Added to Tier 3 Crops (Gg N)

	1990	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Fertilizer N	8,994	8,760	8,906	8,540	8,908	8,748	9,052	8,719	8,594	9,594	9,609	9,724	9,842	9,620	9,823

Table A- 221: Fate of Livestock Manure Nitrogen (Gg N)

Activity	1990	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Managed Manure N Applied to Tier 3 Crops and Non-federal Grasslands[a],[b]	992	908	1,098	1,055	1,060	1,051	1,038	1,037	1,004	1,107	1,107	1,107	1,107	1,105	1,104
Managed Manure N Applied to Tier 1 Crops[c]	1,665	1,804	1,750	1,772	1,795	1,822	1,750	1,792	1,889	1,829	1,803	1,790	1,791	1,815	1,831
Managed Manure N Applied to Grasslands	62	61	60	61	62	60	59	59	59	57	57	57	57	57	57
Pasture, Range, & Paddock Manure N	4,293	4,695	4,331	4,319	4,322	4,313	4,256	4,308	4,349	4,253	4,210	4,169	4,123	4,033	4,082
Total	7,012	7,468	7,239	7,208	7,239	7,246	7,104	7,196	7,300	7,247	7,177	7,124	7,078	7,010	7,075

[a] Accounts for N volatilized and leached/runoff during treatment, storage and transport before soil application.

[b] Includes managed manure and daily spread manure amendments

[c] Totals may not sum exactly due to rounding.

Table A-222: Crop Residue N and Other N Inputs to Tier 3 Crops as Simulated by DAYCENT (Gg N)

Activity	1990	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Residue N[a]	578	623	619	631	589	636	664	657	629	628	628	628	628	628	628
Mineralization & Asymbiotic Fixation	11,001	11,834	10,455	11,653	11,300	11,303	12,061	11,343	11,642	11,116	11,116	11,116	11,116	11,116	11,116

[a] Residue N inputs include unharvested fixed N from legumes as well as crop residue N.

Table A- 223: Synthetic Fertilizer N Added to Tier 1 Crops (Gg N)

Activity	1990	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Fertilizer N	1,969	2,181	2,532	2,311	2,261	2,594	2,554	2,450	2,630	2,298	1,914	1,656	1,866	1,974	1,640

Table A- 224: Other Organic Commercial Fertilizer Consumption on Agricultural Lands (Gg N)

Activity	1990	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Other Commercial Organic Fertilizer N[a]	4	10	9	7	8	8	9	10	12	15	12	10	10	10	9

[a] Includes dried blood, tankage, compost, other. Excludes dried manure and sewage sludge used as commercial fertilizer to avoid double counting.

Table A- 225: Sewage Sludge Nitrogen by Disposal Practice (Gg N)

Disposal Practice	1990	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Applied to Agricultural Soils	52	69	84	86	89	91	94	98	101	104	106	109	112	115	118
Other Land Application	25	28	30	30	30	30	30	31	31	32	32	32	32	32	32
Surface Disposal	20	16	10	9	8	6	5	5	4	4	3	3	3	2	2
Total	**98**	**113**	**124**	**125**	**127**	**128**	**130**	**134**	**136**	**139**	**141**	**144**	**147**	**149**	**152**

Note: Totals may not sum due to independent rounding.

Table A- 226: Key Assumptions for Production of Tier 1 Crops and Retention of Crop Residues

Crop	Dry Matter Fraction of Harvested Product	Above-ground Residue		Ratio of Below-ground Residue to Above-ground Biomass	Residue N Fraction	
		Slope	Intercept		Above-ground	Below-ground
Dry Edible Peas	0.91	1.13	0.85	0.19	0.008	0.008
Austrian Winter Peas	0.91	1.13	0.85	0.19	0.008	0.008
Lentils	0.91	1.13	0.85	0.19	0.008	0.008
Wrinkled Seed Peas	0.91	1.13	0.85	0.19	0.008	0.008
Millet	0.90	1.43	0.14	0.22	0.007	0.009

Table A- 227: Nitrogen in Crop Residues Retained on Soils Producing Tier 1 Crops (Gg N)

Crop	1990	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Dry Edible Peas	9	11	10	10	10	11	14	15	8	8	14	17	15	11	14
Austrian Winter Peas	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Lentils	9	9	10	10	9	9	10	11	10	10	9	11	12	10	11
Wrinkled Seed Peas	9	9	8	8	8	8	9	8	8	8	8	9	8	8	8
Millet	7	7	3	7	2	5	6	5	4	6	6	4	5	4	2
Total	**41**	**43**	**40**	**43**	**39**	**41**	**47**	**48**	**39**	**41**	**46**	**48**	**49**	**42**	**43**

Step 1e: Additional Activity Data for Indirect N_2O Emissions from Managed Soils of all Land-Use Types

A portion of the N that is applied as synthetic fertilizer, livestock manure, sewage sludge, and other organic amendments volatilizes as NH_3 and NO_x. In turn, this N is returned to soils through atmospheric deposition, thereby increasing mineral N availability and enhancing N_2O production. Additional N is lost from soils through leaching as water percolates through a soil profile and through runoff with overland water flow. N losses from leaching and runoff enter groundwater and waterways, from which a portion is emitted as N_2O. However, N leaching is assumed to be an insignificant source of indirect N_2O in cropland and grassland systems where the amount of precipitation plus irrigation does not exceed 80 percent of the potential evapotranspiration. These areas are typically semi-arid to arid, and nitrate leaching to groundwater is a relatively uncommon event; moreover IPCC (2006) recommends limiting the amount of nitrate leaching assumed to be a source of indirect N_2O emissions based on precipitation, irrigation and potential evapotranspiration.

The activity data for synthetic fertilizer, livestock manure, other organic amendments, residue N inputs, sewage sludge N, and other N inputs are the same as those used in the calculation of direct emissions from agricultural mineral soils, and may be found in Table A- 220 through Table A- 224, Table A- 227, and Table A-225. The activity data for computing direct and indirect N_2O emissions from settlements and forest lands are described in the Land Use, Land-Use Change, and Forestry section of this report.

Using the DAYCENT model, volatilization and leaching/surface run-off of N from soils is computed internally for Tier 3 crops and non-federal grasslands. DAYCENT simulates the processes leading to these losses of N based on environmental conditions (i.e., weather patterns and soil characteristics), management impacts (e.g., plowing, irrigation, harvest), and soil N availability. Note that the DAYCENT model accounts for losses of N from all anthropogenic activity, not just the inputs of N from mineral fertilization and organic amendments, which are addressed in the Tier 1 methodology. Similarly, the N available for producing indirect emissions resulting from grassland management as well as deposited PRP manure is also estimated by DAYCENT. Estimated leaching losses of N from DAYCENT are not used in the indirect N_2O calculation if the amount of precipitation plus irrigation did not exceed 80 percent of the potential evapotranspiration. Volatilized losses of N are summed for each day in the annual cycle to provide an estimate of the amount of N subject to indirect N_2O emissions. In addition, the daily losses of N through leaching and runoff in overland flow are summed for the annual cycle. The implied emission factor for N volatilization ranges from 7 to 9 percent for cropland (Table A-15, Tier 1 default value is 10 percent). The implied emission factor for NO_3^- from leaching/runoff ranges from 25 to 31 percent for cropland (Table A-15, Tier 1 default value is 30 percent). The implied emission factor for N volatilization ranges from 21 to 57 percent for grassland (Table A-16, Tier 1 default value is 20 percent). The implied emission factor for NO_3^- from leaching/runoff ranges from 14 to 22 percent for grassland (Table A-16, Tier 1 default value is 30 percent). Uncertainty in the estimates is derived from uncertainties in the activity data for the N inputs (i.e., fertilizer and organic amendments; see Step 1a for further information).

The Tier 1 method is used to estimate N losses from mineral soils due to volatilization and leaching/runoff for crops, forestland, settlements, sewage sludge applications, and PRP manure on federal grasslands not accounted for by DAYCENT simulations. To estimate volatilized losses, synthetic fertilizers, manure, sewage sludge, and other organic N inputs are multiplied by the fraction subject to gaseous losses using the respective default values of 0.1 kg N/kg N added as mineral fertilizers and 0.2 kg N/kg N added as manure (IPCC 2006). Uncertainty in the volatilized N ranges from 0.03-0.3 kg NH_3-N+NOx-N/kg N for synthetic fertilizer and 0.05-0.5 kg NH_3-N+NOx-N/kg N for organic amendments (IPCC 2006). Leaching/runoff losses of N are estimated by summing the N additions from synthetic and other organic fertilizers, manure, sewage sludge, and above- and below-ground crop residues, and then multiplying by the default fraction subject to leaching/runoff losses of 0.3 kg N/kg N applied, with an uncertainty from 0.1–0.8 kg NO_3-N/kg N (IPCC 2006). However, N leaching is assumed to be an insignificant source of indirect N_2O emissions if the amount of precipitation plus irrigation did not exceed 80 percent of the potential evapotranspiration. PDFs are derived for each of the N inputs in the same manner as direct N_2O emissions, discussed in Steps 1a and 1c.

Volatilized N is summed for losses from Tier 3 crop types, Tier 1 crop types, federal and non-federal grasslands, settlements, and forest lands. Similarly, the annual amounts of N lost from soil profiles through leaching and surface runoff are summed to obtain the total losses for this pathway.

Step 2: Estimate Soil Organic C Stock Changes and Direct N_2O Emissions from Mineral Soils

In this step, soil organic C stock changes and N_2O emissions are estimated for Tier 3 crops, Tier 1 crops, federal and non-federal grasslands. Three methods are used to estimate soil organic C stock changes and direct N_2O emissions from mineral soils. The DAYCENT process-based model is used for Tier 3 croplands and non-federal grasslands. A Tier 2 method is used to estimate soil organic C stock changes for crop histories that included crops that were not simulated by DAYCENT and land use change other than conversions between cropland and grassland. A Tier 1 methodology is used to estimate N_2O emissions from Tier 1 crops, which are grown on a considerably smaller portion of land than the Tier 3 crops, as well as PRP manure N deposition on federal grasslands. Soil organic C stock changes and N_2O emissions are not estimated for federal grasslands (other than the effect of PRP manure N), but are under evaluation as a planned improvement and may be estimated in future inventories.

Step 2a: Estimate Soil Organic C Stock Changes and N_2O Emissions for Crops and Non-Federal Grassland with the Tier 3 DAYCENT Model

Tier 3 crops include alfalfa hay, barley, corn, cotton, dry beans, grass hay, grass-clover hay, oats, onions, peanuts, potatoes, rice, sorghum, soybeans, sugar beets, sunflowers, tomatoes, and wheat, which represent approximately 85-87 percent of total cropland in the United States. The DAYCENT simulations also included all non-federal grasslands in the United States.

The methodology description is divided into two sub-steps. First, the model is used to establish the initial conditions and C stocks for 1979, which is the last year before the NRI survey is initiated. In the second sub-step, DAYCENT is used to estimate changes in soil organic C stocks and direct N_2O emissions based on the land-use and management histories recorded in the NRI from 1990 through 2007 (USDA-NRCS 2009).

Simulate Initial Conditions (Pre-NRI Conditions): DAYCENT model initialization involves two steps, with the goal of estimating the most accurate stock for the pre-NRI history, and the distribution of organic C among the pools represented in the model (e.g., Structural, Metabolic, Active, Slow, and Passive). Each pool has a different turnover rate (representing the heterogeneous nature of soil organic matter), and the amount of C in each pool at any point in time influences the forward trajectory of the total soil organic C storage. There is currently no national set of soil C measurements that can be used for establishing initial conditions in the model. Sensitivity analysis of the soil organic C algorithms showed that the rate of change of soil organic matter is relatively insensitive to the *amount* of total soil organic C but is highly sensitive to the relative *distribution* of C among different pools (Parton et al. 1987). By simulating the historical land use prior to the inventory period, initial pool distributions are estimated in an unbiased way.

The first step involves running the model to a steady-state condition (e.g., equilibrium) under native vegetation, historical climate data based on the NARR product (1980-2007), and the soil physical attributes for the NRI points. Native vegetation is represented at the MLRA level for pre-settlement time periods in the United States. The model simulates 5,000 years in the pre-settlement era in order to achieve a steady-state condition.

The second step is to simulate the period of time from European settlement and expansion of agriculture to the beginning of the NRI survey, representing the influence of historic land-use change and management, particularly the conversion of native vegetation to agricultural uses. This encompasses a varying time period from land conversion (depending on historical settlement patterns) to 1979. The information on historical cropping practices used for DAYCENT simulations has been gathered from a variety of sources, ranging from the historical accounts of farming practices reported in the literature (e.g., Miner 1998) to national level databases (e.g., NASS 2004). A detailed description of the data sources and assumptions used in constructing the base history scenarios of agricultural practices can be found in Williams and Paustian (2005).

NRI History Simulations: After model initialization, DAYCENT is used to simulate the NRI land use and management histories from 1979 through 2007.[88] The simulations address the influence of soil management on direct N_2O emissions, soil organic C stock changes and losses of N from the profile through leaching/runoff and volatilization. The NRI histories identify the land use and land use change histories for the NRI survey locations, as well as cropping patterns and irrigation history (see Step 1a for description of the NRI data). The input data for the model simulations also include the NARR weather dataset and SSURGO soils data, synthetic N fertilizer rates, managed manure amendments to cropland and grassland, manure deposition on grasslands (i.e., PRP), tillage histories and EVI data (See Step 1b for description of the inputs). The total number of DAYCENT simulations is over 18 million with a 100 repeated simulations (i.e., iterations) for each NRI point location in a Monte Carlo Analysis. The simulation system incorporates a dedicated MySQL database server and a 30-node parallel processing computer cluster. Input/output operations are managed by a set of run executive programs written in PERL.

The simulations for the NRI history are integrated with the uncertainty analysis. Evaluating uncertainty is an integral part of the analysis, and includes three components: (1) uncertainty in the main activity data inputs affecting soil C and N_2O emissions (input uncertainty); (2) uncertainty in the model formulation and parameterization (structural uncertainty); and (3) uncertainty in the land-use and management system areas (scaling uncertainty) (Ogle et al. 2010, Del Grosso et al. 2010). For component 1, input uncertainty is evaluated for fertilization management, manure applications, and tillage, which are primary management activity data that are supplemental to the NRI observations and have significant influence on soil organic C dynamics and N_2O emissions. As described in Step 1b, PDFs are derived from surveys at the county scale for the inputs in most cases. In addition, uncertainty is included for predictions of EVI data that are needed to fill-data gaps and extend the time series (see Enhanced Vegetation Index in Step 1b). To represent uncertainty in all of these inputs, a Monte-Carlo Analysis is used with 100 iterations for each NRI point; random draws are made from PDFs for fertilizer, manure application, tillage, and EVI predictions. As described above, an adjustment factor is also selected from PDFs with normal densities to represent the dependence between manure amendments and N fertilizer application rates.

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[88] The estimated soil C stock change in 2007 is currently assumed to represent the changes between 2008 and 2012. New estimates will be available in the future to extend the time series of land use and management data.

The second component deals with uncertainty inherent in model formulation and parameterization. This component is the largest source of uncertainty in the Tier 3 model-based inventory analysis, accounting for more than 80 percent of the overall uncertainty in the final estimates (Ogle et al. 2010, Del Grosso et al. 2010). An empirically-based procedure is applied to develop a structural uncertainty estimator from the relationship between modeled results and field measurements from agricultural experiments (Ogle et al. 2007). For soil organic C, the DAYCENT model is evaluated with measurements from 84 long-term field experiments that have over 900 treatments, representing a variety of management conditions (e.g., variation in crop rotation, tillage, fertilization rates, and manure amendments). There are 24 experimental sites available to evaluate structural uncertainty in the N_2O emission predictions from DAYCENT (Del Grosso et al. 2010). The inputs to the model are essentially known in the simulations for the long-term experiments, and, therefore, the analysis is designed to evaluate uncertainties associated with the model structure (i.e., model algorithms and parameterization). USDA is developing a national soil monitoring network to evaluate the Inventory in the future (Spencer et al. 2011).

The relationship between modeled soil organic C stocks and field measurements are statistically analyzed using linear-mixed effect modeling techniques. Additional fixed effects are included in the mixed effect model if they explained significant variation in the relationship between modeled and measured stocks (i.e., if they met an alpha level of 0.05 for significance). Several variables are tested, including land-use class; type of tillage; cropping system; geographic location; climate; soil texture; time since the management change; original land cover (i.e., forest or grassland); grain harvest as predicted by the model compared to the experimental values; and variation in fertilizer and residue management. The final cropland model includes variables for modeled soil organic C inclusion of hay/pasture in cropping rotations, use of no-till, set-aside lands, organic matter amendments, and inclusion of bare fallow in the rotation, which are significant at an alpha level of 0.05. The final grassland model only included the model soil organic C. These fixed effects are used to make an adjustment to modeled values due to biases that are creating significant mismatches between the modeled and measured stocks. For soil N_2O, simulated DAYCENT emissions are a highly significant predictor of the measurements, with a p-value of <0.01. Several other variables are considered in the statistical model to evaluate if DAYCENT exhibits bias under certain conditions related to climate, soil types, and management practices. The type of crop is significant at an alpha level of 0.05, demonstrating that DAYCENT tends to over-estimate emissions for small grains systems, but is accurate in predicting the N_2O emissions for other crops and grassland. Random effects are included in the model to capture the dependence in time series and data collected from the same site, which are needed to estimate appropriate standard deviations for parameter coefficients.

A Monte Carlo approach is used to apply the uncertainty estimator (Ogle et al. 2010). Parameter values for the statistical equation (i.e., fixed effects) are selected from their joint probability distribution, as well as random error associated with fine-scale estimates at NRI points, and the residual or unexplained error associated with the linear mixed-effect model. The estimate and associated management information is then used as input into the equation, and adjusted values are computed for each C stock and N_2O emissions estimate. The variance of the adjusted estimates is computed from the 100 simulated values from the Monte Carlo analysis.

The third element is the uncertainty associated with scaling the DAYCENT results for each NRI point to the entire land base, using the expansion factors provided with the NRI survey dataset. The expansion factors represent the number of hectares associated with the land-use and management history for a particular point. This uncertainty is determined by computing the variances from a set of replicated weights for the expansion factor.

For the land base that is simulated with the DAYCENT model, soil organic C stock changes are provided in Table A-228, and soil N_2O emissions are provided in Table A-229.

Table A-228: Annual Change in Soil Organic Carbon Stocks (95% Confidence Interval) for the Land Base Simulated with the Tier 3 DAYCENT Model-Based Approach (Tg CO_2 Eq.)

	Cropland Remaining Cropland		Land Converted to Cropland		Grassland Remaining Grassland		Land Converted to Grassland	
Year	Estimate	95% CI	Estimate	95% CI	Estimate	95% CI	Estimate	95% CI
1990	(69.39)	(111.58) to (27.19)	19.99	9.49 to 30.49	(13.36)	(48.70) to 21.97	(4.57)	(9.48) to 0.33
1991	(74.40)	(113.19) to (35.60)	17.32	5.98 to 28.65	(2.56)	(41.30) to 36.18	(5.31)	(10.02) to (0.60)
1992	(66.23)	(104.48) to (27.97)	19.15	8.63 to 29.66	(11.34)	(46.88) to 24.19	(4.86)	(10.16) to 0.43
1993	(45.70)	(82.77) to (8.64)	20.15	7.94 to 32.36	(0.65)	(35.56) to 34.26	(3.85)	(9.06) to 1.36
1994	(53.00)	(86.46) to (19.53)	12.25	(1.92) to 26.42	(18.10)	(56.56) to 20.35	(5.35)	(10.68) to (0.02)
1995	(41.87)	(78.60) to (5.15)	20.28	7.18 to 33.38	1.68	(36.44) to 39.81	(5.53)	(10.54) to (0.52)

1996	(51.50)	(90.24) to (12.77)	16.20	3.96 to 28.44	(21.59)	(61.91) to 18.73	(6.34)	(12.09) to (0.58)
1997	(46.79)	(85.92) to (7.66)	16.58	3.03 to 30.13	(8.46)	(42.26) to 25.35	(6.03)	(11.91) to (0.14)
1998	(38.32)	(78.24) to 1.59	11.87	(1.95) to 25.70	(9.66)	(45.71) to 26.39	(6.20)	(14.47) to 2.08
1999	(41.27)	(76.37) to (6.16)	12.08	(1.74) to 25.89	0.53	(33.43) to 34.49	(6.62)	(14.01) to 0.77
2000	(57.32)	(97.85) to (16.78)	11.94	0.30 to 23.57	(33.46)	(72.15) to 5.22	(8.67)	(17.0) to (0.35)
2001	(45.18)	(83.56) to (6.81)	13.38	(1.54) to 28.30	(11.47)	(46.22) to 23.28	(7.32)	(14.44) to (0.20)
2002	(37.86)	(75.34) to (0.38)	12.46	0.97 to 23.95	(14.69)	(54.98) to 25.60	(6.98)	(15.62) to 1.65
2003	(35.71)	(72.65) to 1.23	12.91	0.60 to 25.21	(10.48)	(48.22) to 27.26	(6.96)	(15.04) to 1.12
2004	(38.94)	(77.67) to (0.21)	10.59	(0.49) to 21.66	(0.20)	(38.01) to 37.61	(8.18)	(16.58) to 0 .21
2005	(48.71)	(87.49) to (9.93)	14.25	2.01 to 26.50	3.56	(35.96) to 43.08	(7.02)	(15.82) to 1.78
2006	(50.85)	(90.12) to (11.58)	10.97	(1.38) to 23.33	(19.74)	(53.30) to 13.82	(7.04)	(15.70) to 1.62
2007	(50.58)	(93.40) to (7.75)	10.51	(.41) to 21.42	4.83	(30.74) to 40.40	(7.32)	(16.67) to 2.03
2008	(50.58)	(93.40) to (7.75)	10.51	(.41) to 21.42	4.85	(30.71) to 40.41	(7.28)	(16.59) to 2.03
2009	(50.58)	(93.40) to (7.75)	10.51	(.41) to 21.42	4.88	(30.68) to 40.43	(7.24)	(16.50) to 2.03
2010	(50.58)	(93.40) to (7.75)	10.51	(.41) to 21.42	4.90	(30.65) to 40.45	(7.20)	(16.42) to 2.02
2011	(50.58)	(93.40) to (7.75)	10.51	(.41) to 21.42	4.92	(30.62) to 40.46	(7.15)	(16.33) to 2.02
2012	(50.58)	(93.40) to (7.75)	10.51	(.41) to 21.42	4.95	(30.59) to 40.48	(7.11)	(16.25) to 2.02

Note: Estimates after 2007 are based on NRI data from 2007 and therefore do not fully reflect changes occurring in the latter part of the time series.

Table A-229: Annual N_2O Emissions (95% Confidence Interval) for the Land Base Simulated with the Tier 3 DAYCENT Model-Based Approach (Tg CO_2 Eq.)

	Tier 3 Crops		Non-Federal Grasslands	
Year	Estimate	95% CI	Estimate	95% CI
1990	132.1	123.77 to 144.01	74.3	67.37 to 84.96
1991	144.6	135.44 to 157.83	89.7	82.14 to 101.2
1992	146.3	136.76 to 160.06	73.1	68.03 to 80.41
1993	154.6	144.86 to 168.56	79.3	74.12 to 86.92
1994	138.1	129.86 to 150.44	68.0	63.75 to 74.02
1995	141.0	132.4 to 153.96	77.4	72.38 to 84.61
1996	151.4	142.2 to 165.16	84.8	79.24 to 92.74
1997	147.0	137.75 to 160.98	86.3	80.52 to 94.61
1998	125.4	117.28 to 138.09	67.1	62.5 to 73.54
1999	129.3	121.27 to 141.39	66.0	61.86 to 71.77
2000	121.1	113.85 to 131.88	61.5	57.33 to 67.25
2001	133.6	125.47 to 145.5	69.8	64.82 to 76.9
2002	131.5	123.57 to 143.07	64.2	59.92 to 70.37
2003	130.0	122.3 to 141.21	63.9	59.84 to 69.71
2004	138.4	130.06 to 150.46	77.9	72.46 to 85.71
2005	137.4	128.97 to 149.53	74.3	69.61 to 80.97
2006	136.8	128.43 to 148.91	71.3	66.59 to 78.04
2007	144.1	135.14 to 156.8	86.8	80.21 to 96.4
2008	143.7	134.78 to 156.45	86.6	80.01 to 96.18
2009	143.7	134.75 to 156.42	86.3	79.76 to 95.91
2010	139.6	130.73 to 152.46	86.1	79.5 to 95.64
2011	137.9	129.08 to 150.83	85.8	79.25 to 95.36
2012	138.2	129.33 to 151.09	85.6	78.99 to 95.09

In DAYCENT, the model cannot distinguish among the original sources of N after the mineral N enters the soil pools in order to determine which management activity led to specific N_2O emissions. This means, for example, that N_2O emissions from applied synthetic fertilizer cannot be separated from emissions due to other N inputs, such as crop residues. It is desirable, however, to report emissions associated with specific N inputs. Thus, for each NRI point, the N inputs in a simulation are determined for anthropogenic practices discussed in IPCC (2006), including synthetic mineral N fertilization, organic amendments, and crop residue N added to soils (including N-fixing crops). The percentage of N input for anthropogenic practices is divided by the total N input, and this proportion is used to determine the amount of N_2O emissions assigned to each of the practices.[89] For example, if 70 percent of the

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[89] This method is a simplification of reality to allow partitioning of N_2O emissions, as it assumes that all N inputs have an identical chance of being converted to N_2O. This is unlikely to be the case, but DAYCENT does not track N_2O emissions by source of

mineral N made available in the soil is due to mineral fertilization, then 70 percent of the N_2O emissions are assigned to this practice. The remainder of soil N_2O emissions is reported under “other N inputs,” which includes mineralization due to decomposition of soil organic matter and litter, as well as asymbiotic N fixation from the atmosphere. Asymbiotic N fixation by soil bacteria is a minor source of N, typically not exceeding 10 percent of total N inputs to agroecosystems. Mineralization of soil organic matter is a more significant source of N, but is still typically less than half of the amount of N made available in the cropland soils compared to application of synthetic fertilizers and manure amendments, along with symbiotic fixation. Mineralization of soil organic matter accounts for the majority of available N in grassland soils. Accounting for the influence of “other N inputs” is necessary in order to meet the recommendation for reporting all emissions from managed lands (IPCC 2006). While this method allows for attribution of N_2O emissions to the individual N inputs to the soils, it is important to realize that sources such as synthetic fertilization may have a larger impact on N_2O emissions than would be suggested by the associated level of N input for this source (Delgado et al. 2009). Further research will be needed to improve upon this attribution method, however. The results are provided in Table A- 230 and Table A- 231 associated with subdividing the N_2O emissions based on N inputs.

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mineral N so this approximation is the only approach that can be used currently for partitioning N_2O emissions by source of N input. Moreover, this approach is similar to the IPCC Tier 1 method (IPCC 2006), which uses the same direct emissions factor for most N sources (e.g., PRP). Further research and model development may allow for other approaches in the future.

Table A- 230: Direct N_2O Emissions from Cropland Soils (Tg CO_2 Eq.)

N Source	1990	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Total Mineral Soils	**150.4**	**161.0**	**142.6**	**154.2**	**151.9**	**152.2**	**160.0**	**158.7**	**159.5**	**164.8**	**162.5**	**161.1**	**158.1**	**157.0**	**155.7**
Tier 3 Crops	**132.1**	**141.0**	**121.1**	**133.6**	**131.5**	**130.0**	**138.4**	**137.4**	**136.8**	**144.1**	**143.7**	**143.7**	**139.6**	**137.9**	**138.2**
Synthetic Fertilizer	55.9	55.8	50.6	52.1	53.3	51.5	54.8	53.8	51.7	60.4	60.1	61.0	59.5	57.8	59.3
Managed Manure	5.8	5.8	6.1	6.4	6.4	6.2	6.5	6.5	6.5	7.0	7.0	6.9	6.6	6.6	6.6
Residue N[a]	3.3	3.9	3.4	3.8	3.4	3.7	3.9	4.2	3.9	4.0	4.0	4.0	3.9	3.9	3.8
Mineralization and Asymbiotic Fixation	67.0	75.4	61.0	71.4	68.3	68.7	73.2	72.9	74.7	72.6	72.5	71.8	69.5	69.6	68.5
Tier 1 Crops	**18.3**	**20.1**	**21.5**	**20.5**	**20.4**	**22.1**	**21.6**	**21.3**	**22.6**	**20.8**	**18.8**	**17.5**	**18.5**	**19.1**	**17.5**
Synthetic Fertilizer	9.6	10.6	12.3	11.3	11.0	12.6	12.4	11.9	12.8	11.2	9.3	8.1	9.1	9.6	8.0
Managed Manure and Other Organic Commercial Fertilizer	8.1	8.8	8.6	8.7	8.8	8.9	8.6	8.8	9.3	9.0	8.8	8.8	8.8	8.9	9.0
Residue N	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Organic Soils	**4.7**	**4.5**	**4.4**	**4.3**	**4.3**	**4.2**	**4.2**	**4.1**	**4.1**	**4.0**	**4.0**	**4.0**	**4.0**	**4.0**	**4.0**
Total*	**155.1**	**165.6**	**146.9**	**158.5**	**156.1**	**156.3**	**164.2**	**162.8**	**163.5**	**168.9**	**166.5**	**165.2**	**162.1**	**161.0**	**159.8**

+ Less than 0.05 Tg CO_2 Eq.

[a] Residue N inputs include unharvested fixed N from legumes as well as crop residue N.

Table A- 231: Direct N_2O Emissions from Grasslands (Tg CO_2 Eq.)

N Source	1990	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Tier 3	**74.3**	**82.0**	**63.3**	**71.9**	**66.1**	**66.6**	**80.0**	**77.8**	**74.1**	**90.4**	**90.1**	**89.9**	**89.6**	**89.4**	**89.2**
Synthetic Fertilizer	0.5	0.7	0.6	0.7	0.8	0.7	1.0	1.0	1.2	1.0	1.0	1.0	1.0	1.0	0.9
PRP Manure	13.4	14.2	12.3	14.1	13.5	12.3	13.2	13.2	13.1	14.3	14.3	14.2	14.2	14.1	14.1
Managed Manure	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Residue N[a]	2.0	2.5	1.6	2.0	1.9	1.9	2.2	2.4	2.2	2.6	2.6	2.6	2.6	2.5	2.5
Mineralization and Asymbiotic Fixation	58.2	64.4	48.6	54.8	49.6	51.5	63.4	60.8	57.2	72.2	72.0	71.9	71.7	71.5	71.3
Tier 1	**11.3**	**15.5**	**12.4**	**11.9**	**11.4**	**12.3**	**12.3**	**12.7**	**13.5**	**13.2**	**12.9**	**12.6**	**12.2**	**11.5**	**11.9**
PRP Manure	11.0	15.2	12.0	11.5	11.0	11.9	11.8	12.3	13.0	12.7	12.4	12.1	11.7	10.9	11.4
Sewage Sludge	0.3	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6
Total	**85.6**	**97.6**	**75.7**	**83.8**	**77.5**	**78.9**	**92.3**	**90.5**	**87.6**	**103.6**	**103.0**	**102.5**	**101.9**	**100.9**	**101.1**

+ Less than 0.05 Tg CO_2 Eq.

[a] Residue N inputs include unharvested fixed N from legumes as well as crop residue N.

Step 2b: Soil N_2O Emissions from Agricultural Lands on Mineral Soils Approximated with the Tier 1 Approach

To estimate direct N_2O emissions from N additions to Tier 1 crops, the amount of N in applied synthetic fertilizer, manure and other commercial organic fertilizers (i.e., dried blood, tankage, compost, and other) is added to N inputs from crop residues, and the resulting annual totals are multiplied by the IPCC default emission factor of 0.01 kg N_2O-N/kg N (IPCC 2006). The uncertainty is determined based on simple error propagation methods (IPCC 2006). The uncertainty in the default emission factor ranges from 0.3–3.0 kg N_2O-N/kg N (IPCC 2006). For flooded rice soils, the IPCC default emission factor is 0.003 kg N_2O-N/kg N and the uncertainty range is 0.000–0.006 kg N_2O-N/kg N (IPCC 2006). Uncertainty in activity data is ± 20 percent for fertilizer additions (Mosier 2004).[90] Uncertainties in the emission factor and fertilizer additions are combined with uncertainty in the equations used to calculate residue N additions from above- and below-ground biomass dry matter and N concentration to derive overall uncertainty.

The Tier 1 method is also used to estimate emissions from manure N deposited by livestock on federal lands (i.e., PRP manure N), and from sewage sludge application to grasslands. These two sources of N inputs to soils are multiplied by the IPCC (2006) default emission factors (0.01 kg N_2O-N/kg N for sludge and horse, sheep, and goat manure, and 0.02 kg N_2O-N/kg N for cattle, swine, and poultry manure) to estimate N_2O emissions (Table A- 231). The uncertainty is determined based on the Tier 1 error propagation methods provided by the IPCC (2006) with uncertainty in the default emission factor ranging from 0.007 to 0.06 kg N_2O-N/kg N (IPCC 2006).

Step 2c: Soil Organic C Stock Changes in Agricultural Lands on Mineral Soils Approximated with the Tier 2 Approach

Mineral soil organic C stock values are derived for crop rotations that were not simulated by DAYCENT and land converted from non-agricultural land uses to cropland or grassland in 1982, 1992, 1997, 2002 and 2007, based on the land-use and management activity data in conjunction with appropriate reference C stocks, land-use change, management, input, and wetland restoration factors. Each input to the inventory calculations for the Tier 2 approach has some level of uncertainty that is quantified in PDFs, including the land-use and management activity data, reference C stocks, and management factors. A Monte Carlo Analysis is used to quantify uncertainty in soil organic C stock changes for the inventory period based on uncertainty in the inputs. Input values are randomly selected from PDFs in an iterative process to estimate SOC change for 50,000 times and produce a 95 percent confidence interval for the inventory results.

Derive Mineral Soil Organic C Stock Change Factors: Stock change factors representative of U.S. conditions are estimated from published studies (Ogle et al. 2003, Ogle et al. 2006). The numerical factors quantify the impact of changing land use and management on SOC storage in mineral soils, including tillage practices, cropping rotation or intensification, and land conversions between cultivated and native conditions (including set-asides in the Conservation Reserve Program). Studies from the United States and Canada are used in this analysis under the assumption that they would best represent management impacts for the Inventory.

The IPCC inventory methodology for agricultural soils divides climate into eight distinct zones based upon average annual temperature, average annual precipitation, and the length of the dry season (IPCC 2006) (Table A-232). Six of these climate zones occur in the conterminous United States and Hawaii (Eve et al. 2001).

Table A-232: Characteristics of the IPCC Climate Zones that Occur in the United States

Climate Zone	Annual Average Temperature (˚C)	Average Annual Precipitation (mm)	Length of Dry Season (months)
Cold Temperate, Dry	< 10	< Potential Evapotranspiration	NA
Cold Temperate, Moist	< 10	≥ Potential Evapotranspiration	NA
Warm Temperate, Dry	10 – 20	< 600	NA

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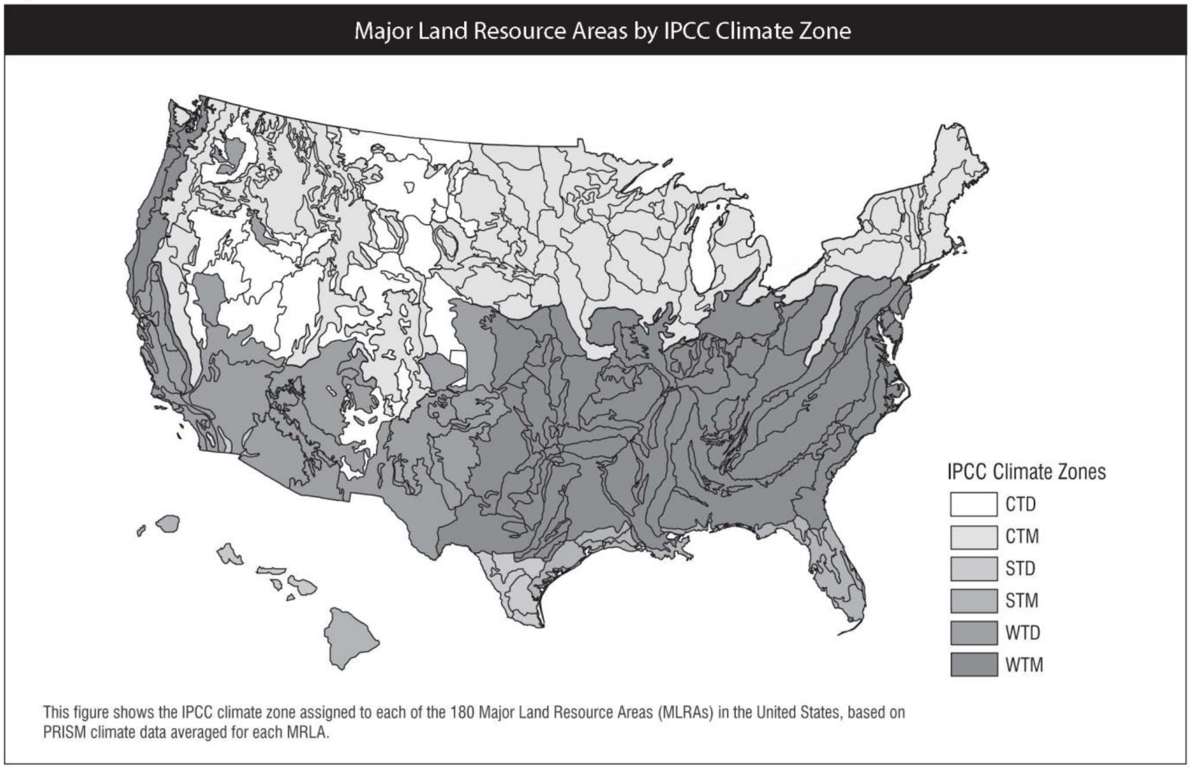
[90] Note that due to lack of data, uncertainties in managed manure N production, PRP manure N production, other commercial organic fertilizer amendments, indirect losses of N in the DAYCENT simulations, and sewage sludge amendments to soils are currently treated as certain; these sources of uncertainty will be included in future Inventories.

Warm Temperate, Moist	10 – 20	≥ Potential Evapotranspiration	NA
Sub-Tropical, Dry[a]	> 20	< 1,000	Usually long
Sub-Tropical, Moist (w/short dry season)[a]	> 20	1,000 – 2,000	< 5

[a] The climate characteristics listed in the table for these zones are those that correspond to the tropical dry and tropical moist zones of the IPCC. They have been renamed "sub-tropical" here.

Mean climate (1961-1990) variables from the PRISM data set (Daly et al. 1994) are used to classify climate zones. Mean annual precipitation and annual temperature data are averaged (weighted by area) for each of the 4×4 km grid cells occurring within a MLRA region. These averages are used to assign a climate zone to each MLRA according to the IPCC climate classification (Figure A-14). MLRAs represent geographic units with relatively similar soils, climate, water resources, and land uses; and there are approximately 180 MLRAs in the United States (NRCS 1981).

Figure A-14: Major Land Resource Areas by IPCC Climate Zone


Major Land Resource Areas by IPCC Climate Zone

This figure shows the IPCC climate zone assigned to each of the 180 Major Land Resource Areas (MLRAs) in the United States, based on PRISM climate data averaged for each MRLA.

Soils are classified into one of seven classes based upon texture, morphology, and ability to store organic matter (IPCC 2006). Six of the categories are mineral types and one is organic (i.e., Histosol). Reference C stocks, representing estimates from conventionally managed cropland, are computed for each of the mineral soil types across the various climate zones, based on pedon (i.e., soil) data from the National Soil Survey Characterization Database (NRCS 1997) (Table A-233). These stocks are used in conjunction with management factors to estimate the change in SOC stocks that result from management and land-use activity. PDFs, which represent the variability in the stock estimates, are constructed as normal densities based on the mean and variance from the pedon data. Pedon locations are clumped in various parts of the country, which reduces the statistical independence of individual pedon estimates. To account for this lack of independence, samples from each climate by soil zone are tested for spatial autocorrelation using the Moran's I test, and variance terms are inflated by 10 percent for all zones with significant p-values.

Table A-233: U.S. Soil Groupings Based on the IPCC Categories and Dominant Taxonomic Soil, and Reference Carbon Stocks (Metric Tons C/ha)

		Reference Carbon Stock in Climate Regions					
IPCC Inventory Soil Categories	USDA Taxonomic Soil Orders	Cold Temperate, Dry	Cold Temperate, Moist	Warm Temperate, Dry	Warm Temperate, Moist	Sub-Tropical, Dry	Sub-Tropical, Moist
High Clay Activity Mineral Soils	Vertisols, Mollisols, Inceptisols, Aridisols, and high base status Alfisols	42 (n = 133)	65 (n = 526)	37 (n = 203)	51 (n = 424)	42 (n = 26)	57 (n = 12)
Low Clay Activity Mineral Soils	Ultisols, Oxisols, acidic Alfisols, and many Entisols	45 (n = 37)	52 (n = 113)	25 (n = 86)	40 (n = 300)	39 (n = 13)	47 (n = 7)
Sandy Soils	Any soils with greater than 70 percent sand and less than 8 percent clay (often Entisols)	24 (n = 5)	40 (n = 43)	16 (n = 19)	30 (n = 102)	33 (n = 186)	50 (n = 18)
Volcanic Soils	Andisols	124 (n = 12)	114 (n = 2)	124 (n = 12)	124 (n = 12)	124 (n = 12)	128 (n = 9)
Spodic Soils	Spodosols	86 (n=20)	74 (n = 13)	86 (n=20)	107 (n = 7)	86 (n=20)	86 (n=20)
Aquic Soils	Soils with Aquic suborder	86 (n = 4)	89 (n = 161)	48 (n = 26)	51 (n = 300)	63 (n = 503)	48 (n = 12)
Organic Soils[a]	Histosols	NA	NA	NA	NA	NA	NA

[a] C stocks are not needed for organic soils.

Notes: C stocks are for the top 30 cm of the soil profile, and are estimated from pedon data available in the National Soil Survey Characterization database (NRCS 1997); sample size provided in parentheses (i.e., 'n' values refer to sample size).

To estimate the land use, management and input factors, studies had to report SOC stocks (or information to compute stocks), depth of sampling, and the number of years since a management change to be included in the analysis. The data are analyzed using linear mixed-effect modeling, accounting for both fixed and random effects. Fixed effects included depth, number of years since a management change, climate, and the type of management change (e.g., reduced tillage vs. no-till). For depth increments, the data are not aggregated for the C stock measurements; each depth increment (e.g., 0-5 cm, 5-10 cm, and 10-30 cm) is included as a separate point in the dataset. Similarly, time series data are not aggregated in these datasets. Linear regression models assume that the underlying data are independent observations, but this is not the case with data from the same experimental site, or plot in a time series. These data are more related to each other than data from other sites (i.e., not independent). Consequently, random effects are needed to account for the dependence in time series data and the dependence among data points representing different depth increments from the same study. Factors are estimated for the effect of management practices at 20 years for the top 30 cm of the soil (Table A-234). Variance is calculated for each of the U.S. factor values, and used to construct PDFs with a normal density. In the IPCC method, specific factor values are given for improved grassland, high input cropland with organic amendments, and for wetland rice, each of which influences C stock changes in soils. Specifically, higher stocks are associated with increased productivity and C inputs (relative to native grassland) on improved grassland with both medium and high input.[91] Organic amendments in annual cropping systems also increase SOC stocks due to greater C inputs, while high SOC stocks in rice cultivation are associated with reduced decomposition due to periodic flooding. There are insufficient field studies to derive factor values for these systems from the published literature, and, thus, estimates from IPCC (2006) are used under the assumption that they would best approximate the impacts, given the lack of sufficient data to derive U.S.-specific factors. A measure of uncertainty is provided for these factors in IPCC (2006), which is used to construct PDFs.

Table A-234: Soil Organic Carbon Stock Change Factors for the United States and the IPCC Default Values Associated with Management Impacts on Mineral Soils

		U.S. Factor			
	IPCC default	Warm Moist Climate	Warm Dry Climate	Cool Moist Climate	Cool Dry Climate
Land-Use Change Factors					
Cultivated[a]	1	1	1	1	1
General Uncult.[a],[b] (n=251)	1.4	1.42±0.06	1.37±0.05	1.24±0.06	1.20±0.06
Set-Aside[a] (n=142)	1.25	1.31±0.06	1.26±0.04	1.14±0.06	1.10±0.05

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[91] Improved grasslands are identified in the 2007 *National Resources Inventory* as grasslands that are irrigated or seeded with legumes, in addition to those reclassified as improved with manure amendments.

Improved Grassland Factors[c]					
Medium Input	1.1	1.14±0.06	1.14±0.06	1.14±0.06	1.14±0.06
High Input	NA	1.11±0.04	1.11±0.04	1.11±0.04	1.11±0.04
Wetland Rice Production Factor[b]	1.1	1.1	1.1	1.1	1.1
Tillage Factors					
Conv. Till	1	1	1	1	1
Red. Till (n=93)	1.05	1.08±0.03	1.01±0.03	1.08±0.03	1.01±0.03
No-till (n=212)	1.1	1.13±0.02	1.05±0.03	1.13±0.02	1.05±0.03
Cropland Input Factors					
Low (n=85)	0.9	0.94±0.01	0.94±0.01	0.94±0.01	0.94±0.01
Medium	1	1	1	1	1
High (n=22)	1.1	1.07±0.02	1.07±0.02	1.07±0.02	1.07±0.02
High with amendment[b]	1.2	1.38±0.06	1.34±0.08	1.38±0.06	1.34±0.08

Note: The "n" values refer to sample size.

[a] Factors in the IPCC documentation (IPCC 2006) are converted to represent changes in SOC storage from a cultivated condition rather than a native condition.

[b] U.S.-specific factors are not estimated for land improvements, rice production, or high input with amendment because of few studies addressing the impact of legume mixtures, irrigation, or manure applications for crop and grassland in the United States, or the impact of wetland rice production in the US. Factors provided in IPCC (2006) are used as the best estimates of these impacts.

Wetland restoration management also influences SOC storage in mineral soils, because restoration leads to higher water tables and inundation of the soil for at least part of the year. A stock change factor is estimated assessing the difference in SOC storage between restored and unrestored wetlands enrolled in the Conservation Reserve Program (Euliss and Gleason 2002), which represents an initial increase of C in the restored soils over the first 10 years (Table A-235). A PDF with a normal density is constructed from these data based on results from a linear regression model. Following the initial increase of C, natural erosion and deposition leads to additional accretion of C in these wetlands. The mass accumulation rate of organic C is estimated using annual sedimentation rates (cm/yr) in combination with percent organic C, and soil bulk density (g/cm^3) (Euliss and Gleason 2002). Procedures for calculation of mass accumulation rate are described in Dean and Gorham (1998); the resulting rate and variance are used to construct a PDF with a normal density (Table A-235).

Table A-235: Factor Estimate for the Initial Increase and Subsequent Annual Mass Accumulation Rate (Mg C/ha-yr) in Soil Organic C Following Wetland Restoration of Conservation Reserve Program

Variable	Value
Factor (Initial Increase—First 10 Years)	1.22±0.18
Mass Accumulation (After Initial 10 Years)	0.79±0.05

Note: Mass accumulation rate represents additional gains in C for mineral soils after the first 10 years (Euliss and Gleason 2002).

Estimate Annual Changes in Mineral Soil Organic C Stocks: In accordance with IPCC methodology, annual changes in mineral soil C are calculated by subtracting the beginning stock from the ending stock and then dividing by 20.[92] For this analysis, the base inventory estimate for 1990 through 1992 is the annual average of 1992 stock minus the 1982 stock. The annual average change between 1993 and 1997 is the difference between the 1997 and 1992 C stocks. The annual average change between 1998 and 2002 is the difference between the 1998 and 2002 C stocks. The annual average change between 2003 and 2012 is the difference between the 2003 and 2007. Using the Monte Carlo approach, SOC stock changes for mineral soils are estimated 50,000 times between 1982 and 1992, 1993 and 1997, 1998 and 2002, and 2003 and 2007. From the final distribution of 50,000 values, a 95 percent confidence interval is generated based on the simulated values at the 2.5 and 97.5 percentiles in the distribution (Ogle et al. 2003). Soil organic C stock changes are provided in Table A-236.

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[92] The difference in C stocks is divided by 20 because the stock change factors represent change over a 20-year time period.

Table A-236: Annual Change in Soil Organic Carbon Stocks (95% Confidence Interval) for the Land Base Estimated with the Tier 2 Analysis using U.S. Factor Values and Reference Carbon Stocks (Tg CO_2 Eq./yr)

Croplands:	Cropland Remaining Cropland		Grassland Converted to Cropland		Forest Converted to Cropland		Other Land Converted to Cropland		Settlements Converted to Cropland		Wetlands Converted to Cropland	
	Estimate	95% CI	Estimate	95% CI	Estimate	95% CI	Estimate	95% CI	Estimate	95% CI	Estimate	95% CI
Mineral Soils												
1990-1992	-6.49	(9.24) to (4.07)	2.34	1.29 to 3.48	1.47	0.81 to 2.18	0.26	0.14 to 0.38	0.56	.31 to .83	0.18	.10 to .27
1993-1997	-7.64	(10.70) to (4.79)	2.02	1.06 to 3.06	1.39	0.73 to 2.12	0.28	0.15 to 0.43	0.74	.39 to 1.13	0.25	.13 to .38
1998-2002	-6.93	(9.67) to (4.44)	1.78	0.90 to 2.73	0.82	0.41 to 1.25	0.27	0.13 to 0.41	0.65	.33 to 1.0	0.21	.10 to .32
2003-2012	-2.82	(5.08) to (0.91)	0.78	0.40 to 1.20	0.26	0.13 to 0.40	0.11	0.06 to 0.17	0.32	.16 to .50	0.08	.04 to .12
Organic Soils												
1990	23.98	15.43 to 34.78	2.51	1.36 to 4.05	0.83	0.34 to 1.51	-	-	0.14	0.06 to 0.26	0.67	0.37 to 1.09
1991	23.72	15.21 to 34.31	2.59	1.40 to 4.12	0.83	0.35 to 1.51	-	-	0.09	0.03 to 0.16	0.67	0.36 to 1.09
1992	23.74	15.27 to 34.52	2.43	1.33 to 3.90	0.77	0.29 to 1.43	-	-	0.09	0.03 to 0.16	0.62	0.34 to .98
1993	23.01	14.68 to 33.58	2.75	1.56 to 4.32	0.81	0.32 to 1.50	-	-	0.19	0.09 to 0.33	0.68	0.39 to 1.06
1994	22.40	14.36 to 32.77	3.10	1.78 to 4.83	0.85	0.35 to 1.55	-	-	0.35	0.18 to 0.59	0.79	0.47 to 1.18
1995	22.19	14.12 to 32.46	3.11	1.77 to 4.90	0.81	0.32 to 1.52	-	-	0.35	0.18 to 0.58	0.80	0.49 to 1.20
1996	21.83	13.88 to 31.93	3.25	1.87 to 5.09	0.93	0.40 to 1.67	-	-	0.36	0.19 to 0.59	0.81	0.49 to 1.22
1997	21.69	13.75 to 31.76	3.33	1.92 to 5.20	0.93	0.40 to 1.67	-	-	0.36	0.19 to 0.59	0.81	0.49 to 1.21
1998	21.72	13.63 to 32.09	3.44	1.85 to 5.55	0.83	0.30 to 1.58	-	-	0.36	0.08 to 0.73	0.86	0.25 to 1.68
1999	21.64	13.63 to 31.77	3.34	1.77 to 5.44	0.76	0.31 to 1.39	-	-	0.36	0.08 to 0.72	0.67	0.28 to 1.26
2000	21.52	13.51 to 31.60	3.26	1.77 to 5.27	0.70	0.27 to 1.31	-	-	0.26	0.04 to 0.55	0.62	0.24 to 1.20
2001	21.96	13.84 to 32.17	4.68	1.91 to 9.31	0.42	0.14 to 0.80	-	-	0.29	0.06 to 0.59	0.62	0.24 to 1.19
2002	21.92	13.85 to 32.08	4.34	1.73 to 8.88	0.29	0.04 to 0.63	-	-	0.27	0.05 to 0.57	0.48	0.17 to 1.01
2003	22.92	14.50 to 33.46	4.04	1.70 to 7.89	0.26	0.02 to 0.60	-	-	0.27	0.04 to 0.56	0.30	0.15 to 0.50
2004	22.61	14.24 to 33.46	4.36	1.03 to 11.27	0.29	0.0 to 0.95	-	-	0.21	0.12 to 0.34	0.30	0.14 to 0.50
2005	22.39	14.06 to 33.01	4.29	0.95 to 11.22	0.27	0.0 to 0.91	-	-	0.21	0.12 to 0.34	0.30	0.14 to 0.50
2006	22.29	13.98 to 32.83	4.17	0.86 to 11.10	0.22	0.0 to 0.81	-	-	0.20	0.11 to 0.32	0.30	0.14 to 0.50
2007	22.14	14.05 to 32.46	4.02	0.69 to 10.93	0.23	0.0 to 0.81	-	-	0.18	0.10 to 0.29	0.36	0.17 to 0.61
2008	22.14	14.05 to 32.46	4.02	0.69 to 10.93	0.23	0.0 to 0.81	-	-	0.18	0.10 to 0.29	0.36	0.17 to 0.61
2009	22.14	14.05 to 32.46	4.02	0.69 to 10.93	0.23	0.0 to 0.81	-	-	0.18	0.10 to 0.29	0.36	0.17 to 0.61
2010	22.14	14.05 to 32.46	4.02	0.69 to 10.93	0.23	0.0 to 0.81	-	-	0.18	0.10 to 0.29	0.36	0.17 to 0.61
2011	22.14	14.05 to 32.46	4.02	0.69 to 10.93	0.23	0.0 to 0.81	-	-	0.18	0.10 to 0.29	0.36	0.17 to 0.61
2012	22.14	14.05 to 32.46	4.02	0.69 to 10.93	0.23	0.0 to 0.81	-	-	0.18	0.10 to 0.29	0.36	0.17 to 0.61

Note: Estimates after 2007 are based on NRI data from 2007 and therefore do not fully reflect changes occurring in the latter part of the time series.

Grasslands:	Grassland Remaining Grassland		Cropland Converted to Grassland		Forest Converted to Grassland		Other Land Converted to Grassland		Settlements Converted to Grassland		Wetlands Converted to Grassland	
	Estimate	95% CI	Estimate	95% CI	Estimate	95% CI	Estimate	95% CI	Estimate	95% CI	Estimate	95% CI
Mineral Soils												
1990-1992	-0.19	(0.38) to (0.03)	-1.73	(2.41) to (1.06)	-1.07	(1.51) to (0.67)	-0.19	(0.27) to (0.12)	-0.41	(0.58) to (0.26)	-0.13	(0.19) to (0.08)
1993-1997	-0.08	(0.18) to 0.0	-1.56	(2.18) to (0.94)	-1.06	(1.51) to (0.65)	-0.21	(0.31) to (0.13)	-0.56	(0.80) to (0.35)	-0.19	(0.27) to (0.12)
1998-2002	-0.01	(0.08) to 0.06	-1.74	(2.47) to (1.03)	-0.79	(1.14) to (0.47)	-0.26	(0.37) to (0.15)	-0.63	(0.91) to (0.38)	-0.20	(0.29) to (0.12)

2003-2012	0.10	0.01 to 0.21	-1.28	(1.86) to (0.71)	-0.42	(0.62) to (0.24)	-0.18	(0.27) to (0.10)	-0.52	(0.77) to (0.29)	-0.13	(0.19) to (0.07)
Organic Soils												
1990	4.60	2.54 to 7.33	0.54	0.24 to 0.98	0.11	0.03 to 0.23	-	-	0.01	0.0 to 0.05	0.10	0.02 to 0.22
1991	4.50	2.47 to 7.19	0.50	0.22 to 0.92	0.11	0.03 to 0.24	0.02	0.0 to 0.05	0.01	0.0 to 0.05	0.10	0.02 to 0.22
1992	4.47	2.45 to 7.14	0.55	0.24 to 0.99	0.11	0.03 to 0.23	-	-	0.01	0.0 to 0.05	0.10	0.01 to 0.24
1993	4.40	2.42 to 7.03	0.56	0.25 to 1.02	0.10	0.03 to 0.22	-	-	0.02	0.0 to 0.06	0.11	0.03 to 0.24
1994	4.29	2.37 to 6.87	0.69	0.31 to 1.23	0.11	0.02 to 0.23	-	-	0.02	0.0 to 0.06	0.16	0.07 to 0.31
1995	4.14	2.28 to 6.61	0.73	0.34 to 1.30	0.11	0.02 to 0.23	-	-	0.02	0.0 to 0.06	0.17	0.07 to 0.32
1996	4.04	2.22 to 6.47	0.71	0.33 to 1.25	0.10	0.02 to 0.23	-	-	0.02	0.0 to 0.06	0.17	0.07 to 0.32
1997	3.91	2.14 to 6.28	0.74	0.35 to 1.30	0.11	0.02 to 0.23	0.01	0.0 to 0.04	0.01	0.0 to 0.03	0.17	0.07 to 0.32
1998	3.80	1.96 to 6.32	0.89	0.40 to 1.63	0.10	0.0 to 0.27	-	-	0.02	0.0 to 0.06	0.18	0.05 to 0.38
1999	3.73	1.92 to 6.25	0.89	0.40 to 1.62	0.10	0.0 to 0.27	-	-	0.02	0.0 to 0.06	0.17	0.05 to 0.38
2000	3.69	1.91 to 6.14	0.88	0.40 to 1.62	0.09	0.0 to 0.23	-	-	0.03	0.01 to 0.07	0.17	0.05 to 0.38
2001	3.28	1.76 to 5.33	0.94	0.42 to 1.70	0.08	0.0 to 0.22	-	-	0.02	0.0 to 0.06	0.16	0.04 to 0.35
2002	3.24	1.72 to 5.24	1.05	0.45 to 1.96	0.05	0.0 to 0.16	-	-	0.02	0.0 to 0.06	0.16	0.04 to 0.34
2003	3.08	1.66 to 4.97	0.92	0.39 to 1.73	0.05	0.0 to 0.16	0.01	.0 to 0.05	0.02	0.0 to 0.06	0.09	0.05 to 0.16
2004	3.05	1.66 to 4.90	1.03	0.39 to 2.03	0.07	0.0 to 0.24	-	-	0.03	0.0 to 0.07	0.11	0.05 to 0.19
2005	3.06	1.67 to 4.91	1.05	0.40 to 2.05	0.07	0.0 to 0.24	-	-	0.03	0.0 to 0.07	0.12	0.06 to 0.22
2006	2.97	1.59 to 4.81	0.97	0.36 to 1.93	0.07	0.0 to 0.24	-	-	0.03	0.0 to 0.07	0.11	0.05 to 0.21
2007	3.03	1.62 to 4.93	0.90	0.33 to 1.78	0.07	0.0 to 0.24	-	-	0.03	0.0 to 0.07	0.11	0.05 to 0.20
2008	3.03	1.62 to 4.93	0.90	0.33 to 1.78	0.07	0.0 to 0.24	-	-	0.03	0.0 to 0.07	0.11	0.05 to 0.20
2009	3.03	1.62 to 4.93	0.90	0.33 to 1.78	0.07	0.0 to 0.24	-	-	0.03	0.0 to 0.07	0.11	0.05 to 0.20
2010	3.03	1.62 to 4.93	0.90	0.33 to 1.78	0.07	0.0 to 0.24	-	-	0.03	0.0 to 0.07	0.11	0.05 to 0.20
2011	3.03	1.62 to 4.93	0.90	0.33 to 1.78	0.07	0.0 to 0.24	-	-	0.03	0.0 to 0.07	0.11	0.05 to 0.20
2012	3.03	1.62 to 4.93	0.90	0.33 to 1.78	0.07	0.0 to 0.24	-	-	0.03	0.0 to 0.07	0.11	0.05 to 0.20

Note: Estimates after 2007 are based on NRI data from 2007 and therefore do not fully reflect changes occurring in the latter part of the time series.

Step 2d: Estimate Additional Changes in Soil Organic C Stocks Due to CRP Enrollment after 2007 and Sewage Sludge Amendments

There are two additional land use and management activities in U.S. agricultural lands that are not estimated in Steps 2a and 2b. The first activity involves the application of sewage sludge to agricultural lands. Minimal data exist on where and how much sewage sludge is applied to U.S. agricultural soils, but national estimates of mineral soil land area receiving sewage sludge can be approximated based on sewage sludge N production data, and the assumption that amendments are applied at a rate equivalent to the assimilative capacity from Kellogg et al. (2000). It is assumed that sewage sludge for agricultural land application is applied to grassland because of the high heavy metal content and other pollutants found in human waste, which limits its application to crops. The impact of organic amendments on SOC is calculated as 0.38 metric tonnes C/ha-yr. This rate is based on the IPCC default method and country-specific factors (see Table A-238), by calculating the effect of converting nominal, medium-input grassland to high input improved grassland. The assumptions are that reference C stock are 50 metric tonnes C/ha, which represents a mid-range value of reference C stocks for the cropland soils in the United States,[93] that the land use factor for grassland of 1.4 and 1.11 for high input improved grassland are representative of typical conditions, and that the change in stocks are occurring over a 20 year (default value) time period (i.e., [50 × 1.4 × 1.11 – 50 × 1.4] / 20 = 0.38). A nominal ±50 percent uncertainty is attached to these estimates due to limited information on application and the rate of change in soil C stock change with sewage sludge amendments. The influence of sewage sludge on soil organic C stocks are provided in Table A-238.

The second activity is the change in enrollment for the Conservation Reserve Program after 2007 for mineral soils. Relative to the enrollment in 2007, the total area in the Conservation Reserve Program has decreased from 2008 to 2012 (USDA-FSA 2012). An average annual change in SOC of 0.5 metric tonnes C/ha-yr is used to estimate the effect of the enrollment changes. This rate is based on the IPCC default method and country-specific factors (see Table A-234) by estimating the impact of setting aside a medium input cropping system in the Conservation Reserve Program. The assumptions are that reference C stock are 50 metric tonnes C/ha, which represents a mid-range value for the dominant cropland soils in the United States, and the average country-specific factor is 1.2 for setting-aside cropland from production, with the change in stocks occurring over a 20 year (default value) time period equal to 0.5 (i.e., [50 × 1.2 – 50] / 20 = 0.5). A nominal ±50 percent uncertainty is attached to these estimates due to limited information about the enrollment trends at subregional scales, which creates uncertainty in the rate of soil C stock change (stock change factors for set-aside lands vary by climate region). Estimates and uncertainties are provided in Table A-242.

Step 3: Estimate Soil Organic C Stock Changes and Direct N_2O Emissions from Organic Soils

In this step, soil organic C losses and N_2O emissions are estimated for organic soils that are drained for agricultural production.

Step 3a: Direct N_2O Emissions Due to Drainage of Organic Soils in Cropland and Grassland

To estimate annual N_2O emissions from drainage of organic soils in cropland and grassland, the area of drained organic soils in croplands and grasslands for temperate regions is multiplied by the IPCC (2006) default emission factor for temperate soils and the corresponding area in sub-tropical regions is multiplied by the average (12 kg N_2O-N/ha cultivated) of IPCC (2006) default emission factors for temperate (8 kg N_2O-N/ha cultivated) and tropical (16 kg N_2O-N/ha cultivated) organic soils. The uncertainty is determined based on simple error propagation methods (IPCC 2006), including uncertainty in the default emission factor ranging from 2–24 kg N_2O-N/ha (IPCC 2006).

Step 3b: Soil Organic C Stock Changes Due to Drainage of Organic Soils in Cropland and Grassland

Change in soil organic C stocks due to drainage of cropland and grassland soils are estimated annually from 1990 through 2007, based on the land-use and management activity data in conjunction with appropriate loss rate emission factors. Each input to the inventory for the Tier 2 approach has some level of uncertainty that is quantified

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[93] Reference C stocks are based on cropland soils for the Tier 2 method applied in this Inventory.

in PDFs. A Monte Carlo Analysis is used to quantify uncertainty in soil organic C stock changes for the inventory period based on uncertainty in the inputs. Input values are randomly selected from PDFs in an iterative process to estimate SOC change for 50,000 times and produce a 95 percent confidence interval for the inventory results.

Derive Organic Soil Emission Factors: Organic Soil emission factors representative of U.S. conditions have been estimated from published studies (Ogle et al. 2003), based on subsidence studies in the United States and Canada (Table A-238). PDFs are constructed as normal densities based on the mean C loss rates and associated variances.

Estimate Annual C Emissions from Organic Soils: Losses of C are estimated by applying the Monte Carlo approach to the annual data from 1990 through 2007 from the NRI. The results for 2007 are applied to the years 2007 through 2012. Losses of soil organic C from drainage of cropland and grassland soils are provided in Table A-239.

Step 4: Estimate Indirect N_2O Emissions for All Land-Use Types

In this step, N_2O emissions are estimated for the two indirect emission pathways (N_2O emissions due to volatilization, and N_2O emissions due to leaching and runoff of N), which are summed to yield total indirect N_2O emissions from croplands, grasslands, forest lands, and settlements.

Step 4a: Indirect Soil N_2O Emissions Due to Volatilization

Indirect emissions from volatilization of N inputs from synthetic and commercial organic fertilizers, and PRP manure, are calculated according to the amount of mineral N that is transported in gaseous forms from the soil profile and later emitted as soil N_2O following atmospheric deposition. See Step 1e for additional information about the methods used to compute N losses due to volatilization. The estimated N volatilized for all land-use and livestock activities is multiplied by the IPCC default emission factor of 0.01 kg N_2O-N/kg N (IPCC 2006) to estimate total N_2O emissions from volatilization. The uncertainty is estimated using simple error propagation methods (IPCC 2006), by combining uncertainties in the amount of N volatilized, with uncertainty in the default emission factor ranging from 0.002–0.05 kg N_2O-N/kg N (IPCC 2006). The estimates and uncertainties are provided in Table A- 239.

Step 4b: Indirect Soil N_2O Emissions Due to Leaching and Runoff

The amount of mineral N from synthetic fertilizers, commercial organic fertilizers, PRP manure, crop residue, N mineralization, asymbiotic fixation that is transported from the soil profile in aqueous form is used to calculate indirect emissions from leaching of mineral N from soils and losses in runoff of water associated with overland flow. See Step 1e for additional information about the methods used to compute N losses from soils due to leaching and runoff in overland water flows.

The total amount of N transported from soil profiles through leaching and surface runoff is multiplied by the IPCC default emission factor of 0.0075 kg N_2O-N/kg N (IPCC 2006) to estimate emissions for this source. The emission estimates are provided in Table A-241. The uncertainty is estimated based on simple error propagation methods (IPCC 2006), including uncertainty in the default emission factor ranging from 0.0005 to 0.025 kg N_2O-N/kg N (IPCC 2006).

Step 5: Estimate Total Soil Organic C Stock Changes and N_2O Emissions for U.S. Soils

Step 5a: Estimate Total Soil N_2O Emissions

Total emissions are estimated by adding total direct emissions (from Tier 3 crop types and Tier 1 crop types on mineral cropland soils, drainage and cultivation of organic soils, and grassland management) to indirect emissions for all land use and management activities. Uncertainties in the final estimate are combined using simple error propagation methods (IPCC 2006), and expressed as a 95 percent confidence interval. Estimates and uncertainties are provided in Table A- 237.

Direct and indirect simulated emissions of soil N_2O vary regionally in both croplands and grasslands as a function of N input amount and timing of fertilization, tillage intensity, crop rotation sequence, weather, and soil type. Note that there are other management practices, such as fertilizer formulation (Halvorson et al. 2013), that influence emissions but are not represented in the model simulations. The highest total N_2O emissions from Tier 3 crops occur in Iowa, Illinois, Missouri, Minnesota, the Dakotas, and Kansas (Table A- 243). On a per area unit basis, direct N_2O emissions are high in the northeast and many of the Mississippi River Basin states where there are high N inputs to hay, corn and soybean crops, and in some western states where irrigated crops are grown that require high N inputs (Figure A-15). Note that although the total crop area in the northeast is relatively low, emissions are high on a per unit area basis because a large portion of the cropped area in these states is used for hay production that receives large N inputs from both fertilizer and symbiotic fixation. Indirect emissions tend to be high on a per unit of area basis in some northeastern states and Florida because relatively high rainfall and coarse textured soils facilitates N losses from leaching and runoff and in some Great Plains states where irrigation can contribute to leaching and runoff (Figure A-16).

Direct and indirect emissions from non-federal grasslands are typically lower than those from croplands (Table A- 243, Figure A-17, and Figure A-18) because N inputs tend to be lower, particularly from synthetic fertilizer. Texas, Oklahoma, Kansas, Nebraska, Missouri, Colorado, South Dakota and Montana are the highest emitters for this category because large land areas are suded for pastures and rangeland. On a per unit of area basis, emissions are higher in the Northeastern United States and some of the Great Lakes and Midwestern states because these grasslands are more intensively managed (legume seeding, fertilization) while western rangelands receive few, if any, N inputs. Also, rainfall is limited in most of the western United States, and grasslands are not typically irrigated so minimal leaching and runoff of N occurs in these grasslands, but N volatilization can be substantial.

Figure A-15: Tier 3 Crops,2012 Annual Direct N_2O Emissions, Estimated Using the DAYCENT Model, (kg N./ha/year)

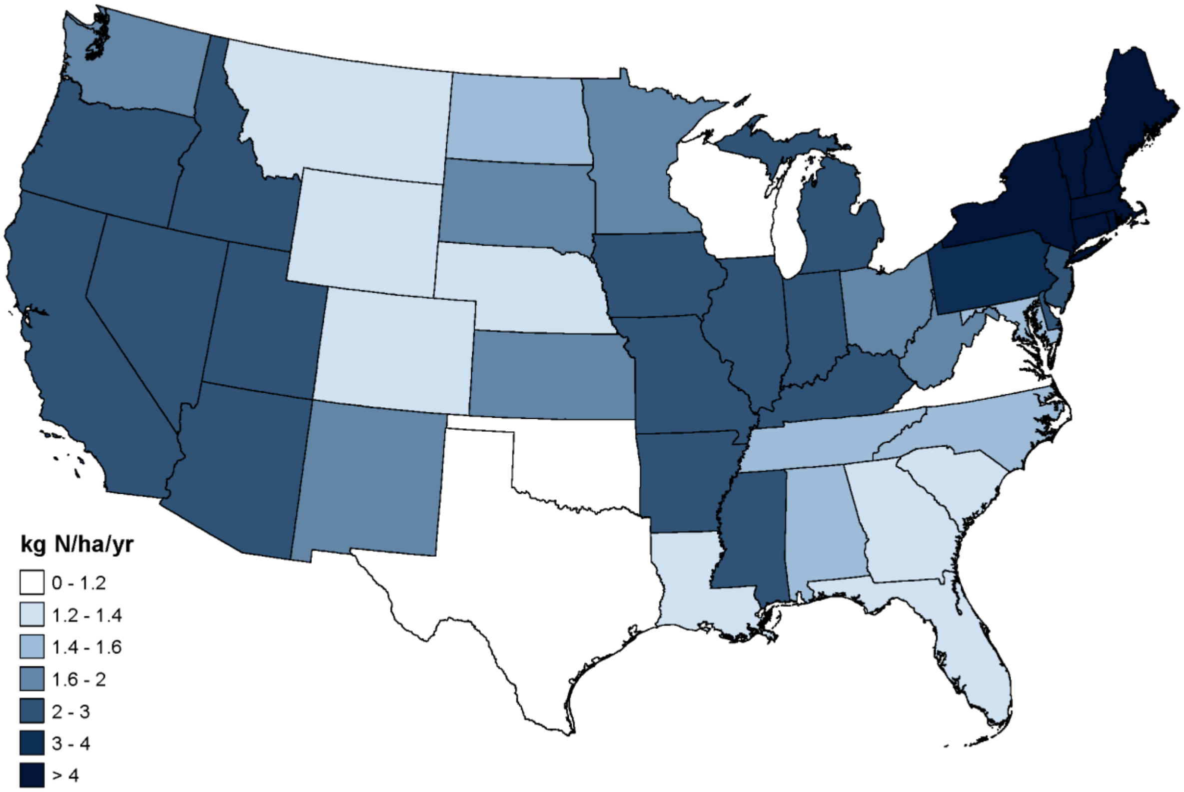


Figure A-16: Tier 3 Crops, 2012 Annual N Losses Leading to Indirect N_2O Emissions, Estimated Using the DAYCENT Model, (kg N/ha/year)

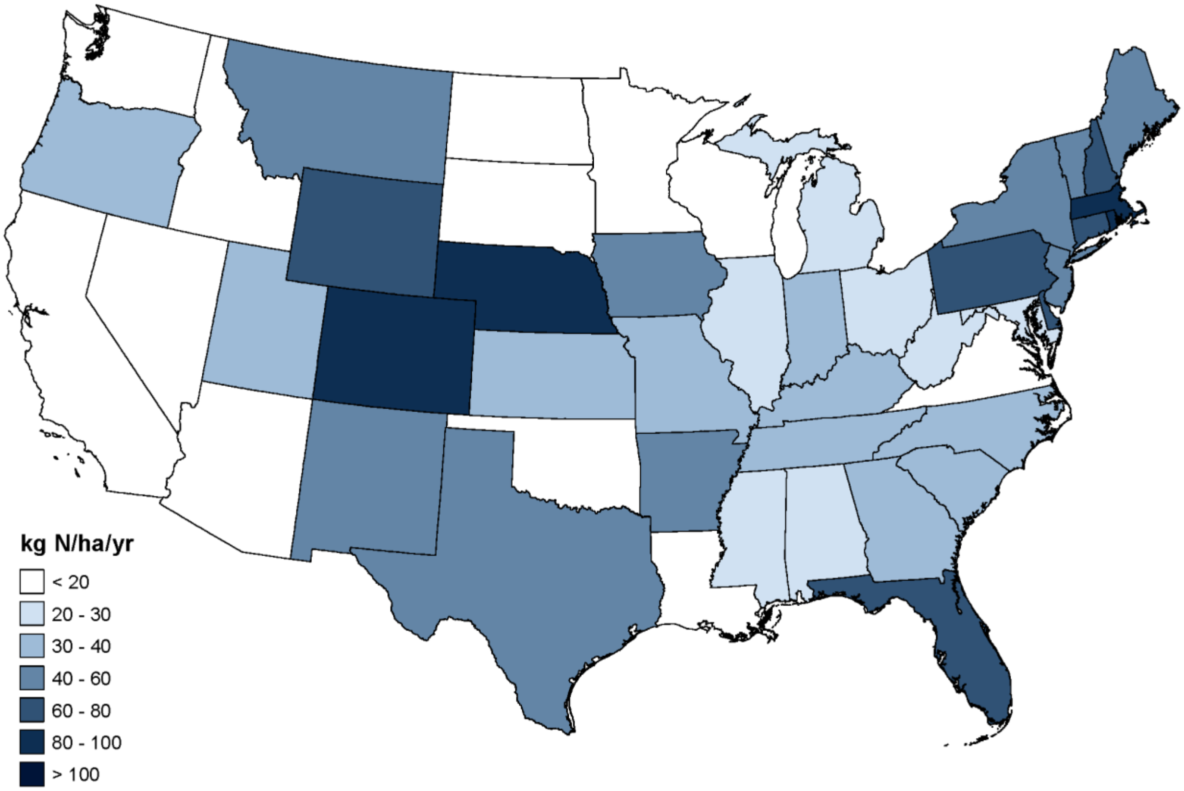


Figure A-17: Non-federal Grasslands, 2012 Annual Direct N_2O Emissions, Estimated Using the DAYCENT Model, (kg N/ha/year)

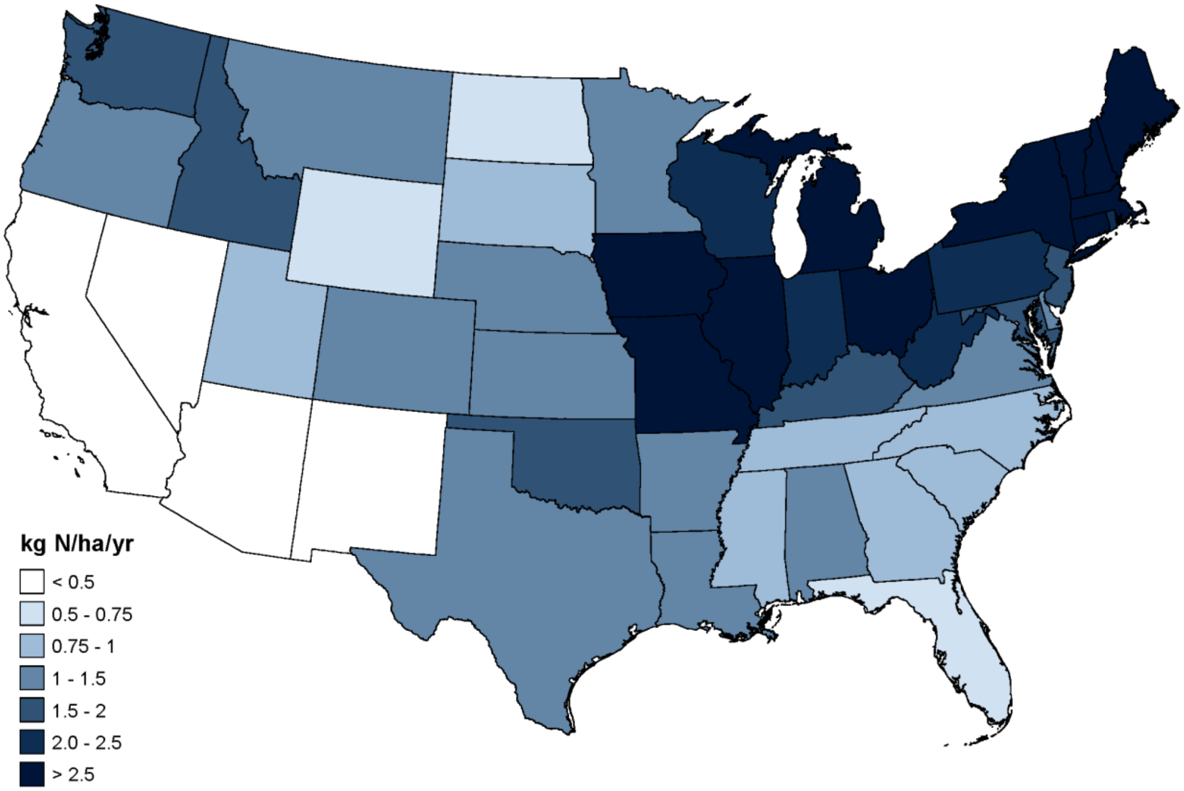
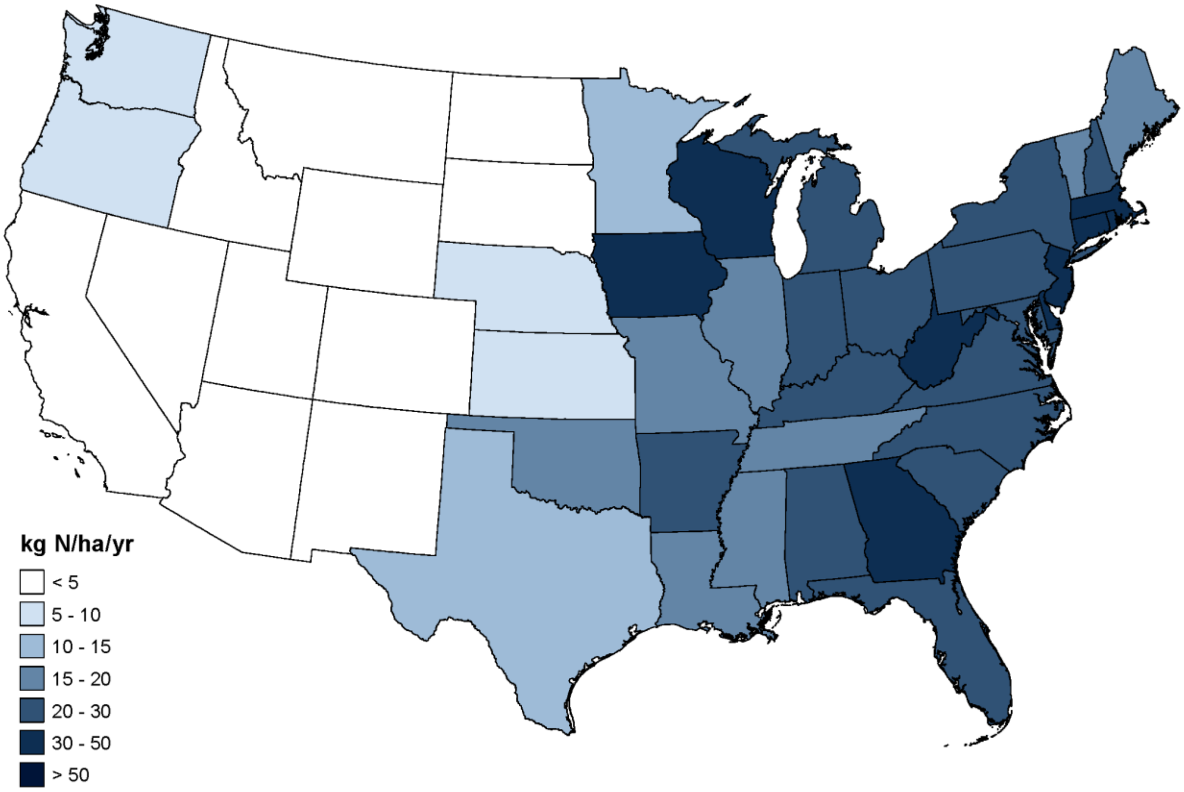


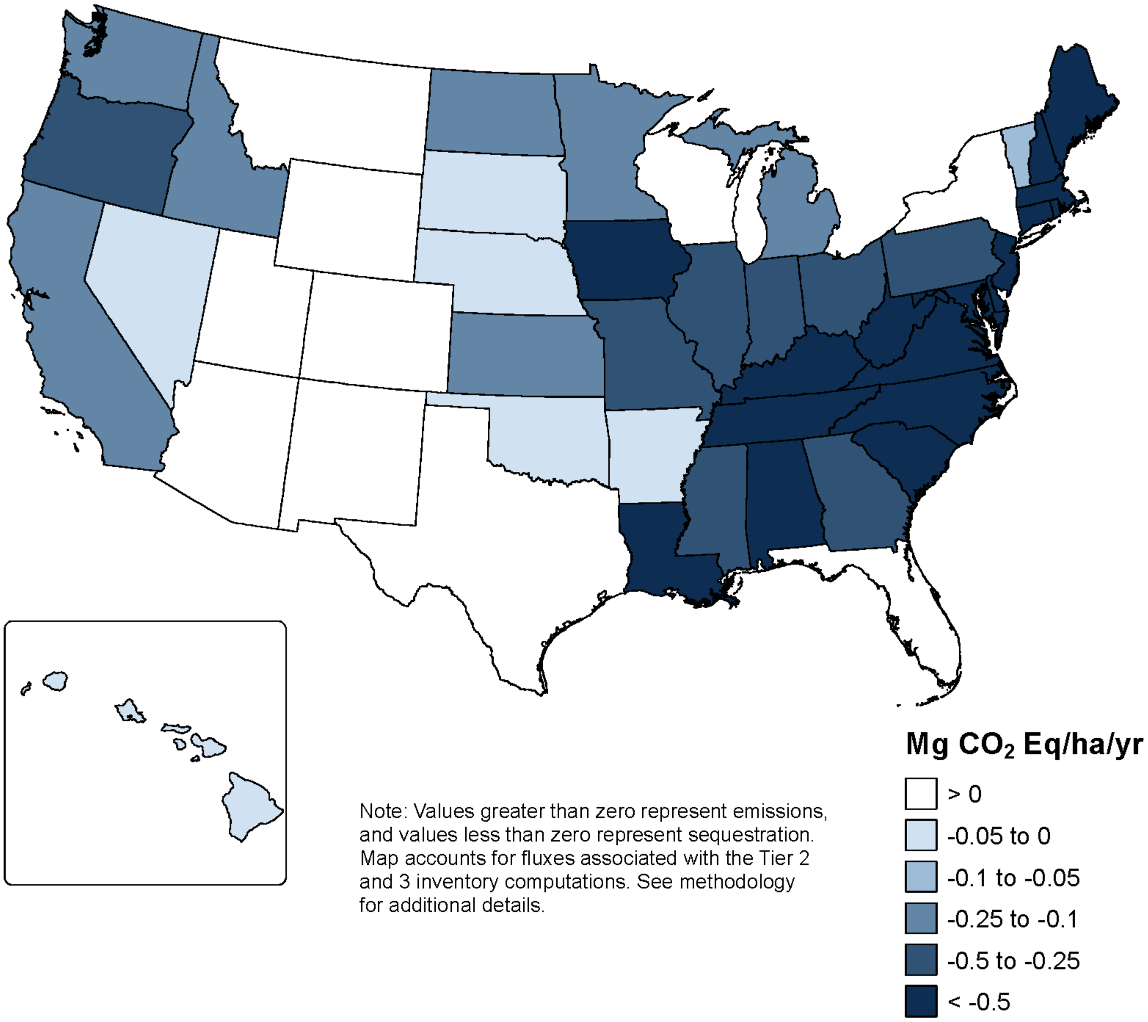
Figure A-18: Non-federal Grasslands, 2012 Annual N Losses Leading to Indirect N_2O Emissions, Estimated Using the DAYCENT Model, (kg N/ha/year)



Step 5b: Estimate Total Soil Organic Stock Change

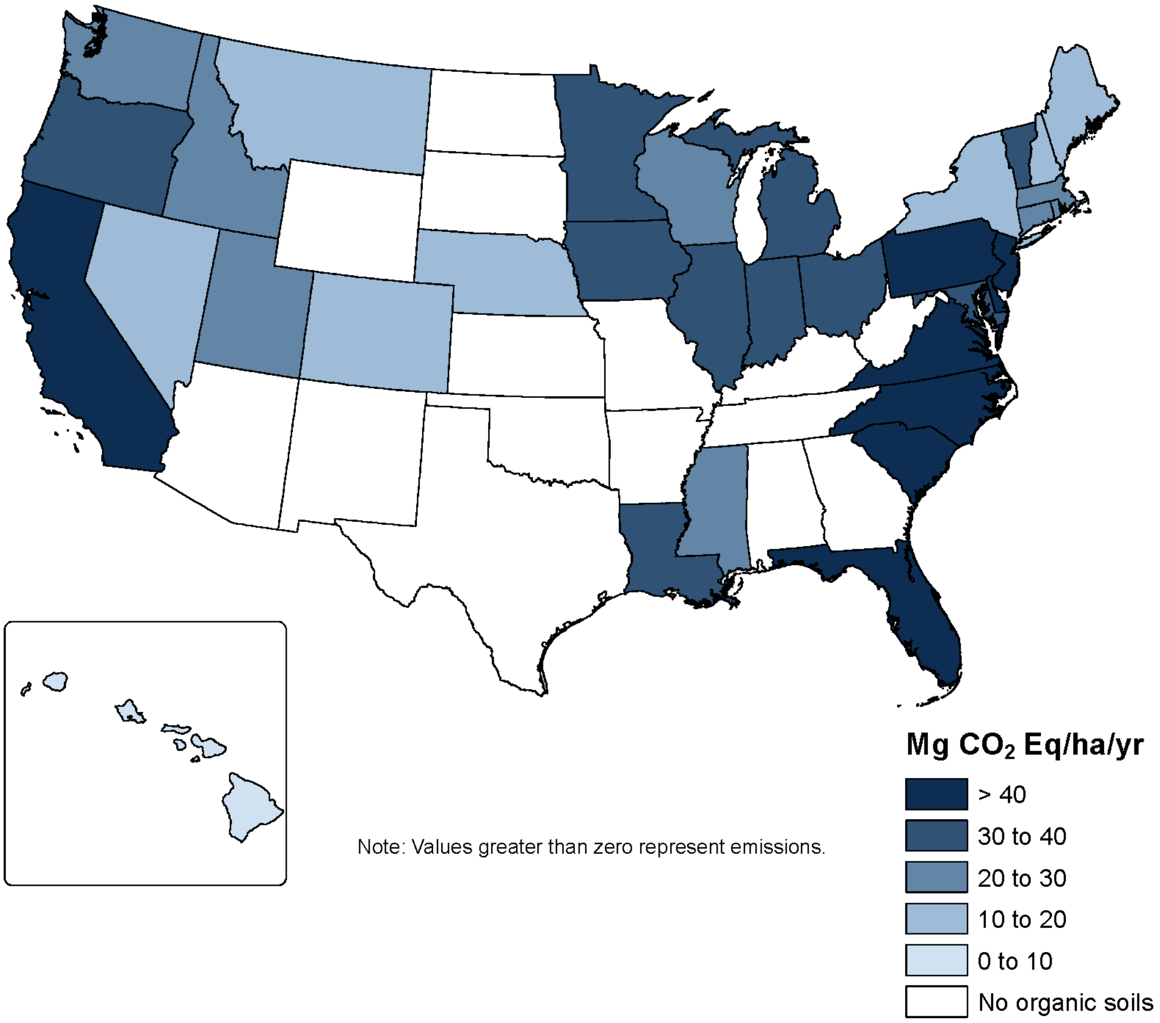
The sum of total CO_2 emissions and removals from the Tier 3 DAYCENT Model Approach, Tier 2 IPCC Methods and additional land-use and management considerations are provided in Table A-242. The total change in soil organic C stocks (as seen in the Land Use, Land-Use Change, and Forestry chapter) as well as per hectare rate of change varies among the states (Figure A-19 and Figure A-20). The states with highest total amounts of C sequestration are Illinois, Iowa, Kansas, Minnesota, Missouri, Ohio and Tennessee (Table A- 244). On a per hectare basis, the highest rates of C accumulation occur in states found in the Southeast, Northeast and Midwest. For organic soils, emission rates are highest in the regions that contain the majority of drained organic soils, including California, Florida, Indiana, Michigan, Minnesota, North Carolina and Wisconsin. On a per unit of area basis, the emission rate patterns are very similar to the total emissions in each state, with the highest rates in coastal states of the Southeast, states surrounding the Great Lakes, and California.

Figure A- 19: Net C Stock Change, per Hectare, for Mineral Soils Under Agricultural Management, 2012



Note: Values greater than zero represent emissions, and values less than zero represent sequestration. Map accounts for fluxes associated with the Tier 2 and 3 inventory computations. See methodology for additional details.

Figure A- 20: Net C Stock Change, per Hectare, for Organic Soils Under Agricultural Management, 2012



Note: Values greater than zero represent emissions.

Table A- 237: Assumptions and Calculations to Estimate the Contribution to Soil Organic Carbon Stocks from Application of Sewage Sludge to Mineral Soils

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Sewage Sludge N Applied to Agricultural Land (Mg N)[a]	52,198	55,658	59,250	62,977	65,966	69,001	72,081	75,195	78,353	80,932	83,523	86,124	88,736	91,358	93,991	98,081	100,887	103,682	106,468	109,245	112,015	114,778	117,536
Assimilative Capacity (Mg N/ha)[b]	0.12	0.12	0.12	0.122	0.122	0.122	0.122	0.122	0.122	0.122	0.122	0.122	0.122	0.122	0.122	0.122	0.122	0.122	0.122	0.122	0.122	0.122	0.122
Area covered by Available Sewage Sludge N (ha)[c]	434,985	463,816	493,746	516,202	540,707	565,583	590,828	616,357	642,240	663,381	684,612	705,932	727,341	748,836	770,418	803,942	826,940	849,851	872,686	895,452	918,156	940,805	963,407
Average Annual Rate of C storage (Mg C/ha-yr)[d]	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38
Contribution to Soil C (TgCO$_2$/yr)[e,f]	**-0.61**	**-0.65**	**-0.69**	**-0.72**	**-0.75**	**-0.79**	**-0.82**	**-0.86**	**-0.89**	**-0.92**	**-0.95**	**-0.98**	**-1.01**	**-1.04**	**-1.07**	**-1.12**	**-1.15**	**-1.18**	**-1.22**	**-1.25**	**-1.28**	**-1.31**	**-1.34**

Values in parentheses indicate net C storage.

[a] N applied to soils described in Step 1d.

[b] Assimilative Capacity is the national average amount of manure-derived N that can be applied on cropland without buildup of nutrients in the soil (Kellogg et al., 2000).

[c] Area covered by sewage sludge N available for application to soils is the available N applied at the assimilative capacity rate. The 1992 assimilative capacity rate was applied to 1990 – 1992 and the 1997 rate was applied to 1993-2012.

[d] Annual rate of C storage based on national average increase in C storage for grazing lands that is attributed to organic matter amendments (0.38 Mg/ha-yr)

[e] Contribution to Soil C is estimated as the product of the area covered by the available sewage sludge N and the average annual C storage attributed to an organic matter amendment.

[f] Some small, undetermined fraction of this applied N is probably not applied to agricultural soils, but instead is applied to forests, home gardens, and other lands.

Table A-238: Carbon Loss Rates for Organic Soils Under Agricultural Management in the United States, and IPCC Default Rates (Metric Ton C/ha-yr)

Region	Cropland IPCC	Cropland U.S. Revised	Grassland IPCC	Grassland U.S. Revised
Cold Temperate, Dry & Cold Temperate, Moist	1	11.2±2.5	0.25	2.8±0.5[a]
Warm Temperate, Dry & Warm Temperate, Moist	10	14.0±2.5	2.5	3.5±0.8[a]
Sub-Tropical, Dry & Sub-Tropical, Moist	1	11.2±2.5	0.25	2.8±0.5[a]

[a] There are not enough data available to estimate a U.S. value for C losses from grassland. Consequently, estimates are 25 percent of the values for cropland, which is an assumption that is used for the IPCC default organic soil C losses on grassland.

Table A- 239: Indirect N_2O Emissions from Volatilization (Tg CO_2 Eq.)

Activity	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Croplands	15.1	16.1	15.8	15.9	16.4	15.8	15.5	15.5	15.5	16.0	15.8	15.9	16.5	15.9	15.5	15.3	15.3	15.5	15.4
Settlements	0.1	0.2	0.2	0.2	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Forest Land	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Grasslands	4.9	5.6	5.4	5.4	5.5	5.1	4.9	5.0	4.9	5.2	5.7	5.5	5.3	5.5	5.5	5.5	5.4	5.3	5.4
Total	**20.2**	**21.9**	**21.4**	**21.5**	**22.1**	**21.0**	**20.6**	**20.8**	**20.6**	**21.4**	**21.7**	**21.6**	**22.0**	**21.7**	**21.3**	**21.0**	**20.9**	**21.0**	**21.0**

+ Less than 0.05 Tg CO_2 Eq.

Table A- 240: Indirect N2O Emissions from Leaching and Runoff (Tg CO2 Eq.)

Activity	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Croplands	16.4	21.3	21.0	16.6	22.1	24.4	14.5	17.9	16.6	14.7	18.8	16.8	14.5	23.6	22.7	22.3	19.8	19.8	19.5
Settlements	0.2	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Forest Land	+	+	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Grasslands	4.5	6.2	6.3	5.8	5.6	5.3	5.0	4.8	4.6	4.9	4.9	5.1	5.4	5.2	5.1	5.0	4.8	4.5	4.8
Total	**21.2**	**27.9**	**27.7**	**22.8**	**28.0**	**30.1**	**19.9**	**23.2**	**21.7**	**20.1**	**24.2**	**22.4**	**20.4**	**29.3**	**28.2**	**27.8**	**25.2**	**24.8**	**24.8**

+ Less than 0.05 Tg CO_2 Eq.

Table A-241: Total N_2O Emissions from Agricultural Soil Management (Tg CO_2 Eq.)

Activity	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Total Direct	**240.7**	**263.2**	**282.0**	**278.1**	**238.8**	**239.6**	**222.7**	**242.3**	**233.6**	**235.2**	**256.5**	**253.3**	**251.1**	**272.4**	**269.5**	**267.6**	**264.0**	**261.9**	**260.9**
Direct Emissions from Mineral Cropland Soils	**150.4**	**161.0**	**173.3**	**169.0**	**149.2**	**153.2**	**142.6**	**154.2**	**151.9**	**152.2**	**160.0**	**158.7**	**159.5**	**164.8**	**162.5**	**161.1**	**158.1**	**157.0**	**155.7**
Synthetic Fertilizer	65.5	66.4	74.4	72.2	62.3	66.0	62.9	63.3	64.3	64.1	67.2	65.8	64.5	71.6	69.5	69.0	68.6	67.4	67.3
Organic Amendment[a]	14.0	14.7	15.2	15.5	14.3	14.9	14.7	15.1	15.2	15.1	15.0	15.3	15.8	16.0	15.8	15.7	15.4	15.5	15.5
Residue N[b]	3.9	4.5	4.7	4.6	4.1	4.4	4.0	4.4	4.0	4.3	4.5	4.8	4.4	4.6	4.6	4.6	4.5	4.5	4.4
Mineralization and Asymbiotic Fixation	67.0	75.4	78.9	76.7	68.6	67.9	61.0	71.4	68.3	68.7	73.2	72.9	74.7	72.6	72.5	71.8	69.5	69.6	68.5
Direct Emissions from Drained Organic Cropland Soils	**4.7**	**4.5**	**4.5**	**4.4**	**4.5**	**4.4**	**4.4**	**4.3**	**4.3**	**4.2**	**4.2**	**4.1**	**4.1**	**4.0**	**4.0**	**4.0**	**4.0**	**4.0**	**4.0**
Direct Emissions from Grasslands	**85.6**	**97.6**	**104.3**	**104.7**	**85.1**	**82.0**	**75.7**	**83.8**	**77.5**	**78.9**	**92.3**	**90.5**	**87.6**	**103.6**	**103.0**	**102.5**	**101.9**	**100.9**	**101.1**
Synthetic Mineral Fertilizer	0.5	0.7	0.8	0.7	0.5	0.7	0.6	0.7	0.8	0.7	1.0	1.0	1.2	1.0	1.0	1.0	1.0	1.0	0.9
PRP Manure	24.5	29.4	31.5	29.8	26.1	26.3	24.3	25.6	24.5	24.1	25.0	25.5	26.2	27.0	26.6	26.3	25.8	25.0	25.4
Managed Manure	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Sewage Sludge	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6
Residue[b]	2.0	2.5	2.7	2.6	2.0	2.0	1.6	2.0	1.9	1.9	2.2	2.4	2.2	2.6	2.6	2.6	2.6	2.5	2.5
Mineralization and Asymbiotic Fixation	58.2	64.4	68.6	70.9	55.8	52.3	48.6	54.8	49.6	51.5	63.4	60.8	57.2	72.2	72.0	71.9	71.7	71.5	71.3
Total Indirect	**41.4**	**49.8**	**49.1**	**44.3**	**50.1**	**51.1**	**40.5**	**43.9**	**42.3**	**41.5**	**45.9**	**44.0**	**42.4**	**51.0**	**49.5**	**48.8**	**46.1**	**45.8**	**45.7**
Volatilization	20.2	21.9	21.4	21.5	22.1	21.0	20.6	20.8	20.6	21.4	21.7	21.6	22.0	21.7	21.3	21.0	20.9	21.0	21.0
Leaching/Runoff	21.2	27.9	27.7	22.8	28.0	30.1	19.9	23.2	21.7	20.1	24.2	22.4	20.4	29.3	28.2	27.8	25.2	24.8	24.8
Total Emissions	**282.1**	**312.9**	**331.2**	**322.5**	**288.8**	**290.7**	**263.2**	**286.2**	**275.9**	**276.7**	**302.4**	**297.3**	**293.6**	**323.4**	**319.0**	**316.4**	**310.1**	**307.8**	**306.6**

+ Less than 0.05 Tg CO_2 Eq.

[a] Organic amendment inputs include managed manure amendments, daily spread manure and other commercial organic fertilizer (i.e., dried blood, tankage, compost, and other).

[b] Residue N inputs include unharvested fixed N from legumes as well as crop residue N.

Table A-242: Annual Soil C Stock Change in *Cropland Remaining Cropland* (CRC), *Land Converted to Cropland* (LCC), *Grassland Remaining Grassland* (GRG), and *Land Converted to Grassland* (LCG), in U.S. Agricultural Soils (Tg CO_2 Eq.)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Net emissions based on Tier 3 Century-based analysis (Step 2)																							
CRC	(69.4)	(74.4)	(66.2)	(45.7)	(53.0)	(41.9)	(51.5)	(46.8)	(38.3)	(41.3)	(57.3)	(45.2)	(37.9)	(35.7)	(38.9)	(48.7)	(50.9)	(50.6)	(50.6)	(50.6)	(50.6)	(50.6)	(50.6)
GCC	20.0	17.3	19.1	20.2	12.3	20.3	16.2	16.6	11.9	12.1	11.9	13.4	12.5	12.9	10.6	14.3	11.0	10.5	10.5	10.5	10.5	10.5	10.5
GRG	(13.4)	(2.6)	(11.3)	(0.7)	(18.1)	1.7	(21.6)	(8.5)	(9.7)	0.5	(33.5)	(11.5)	(14.7)	(10.5)	(0.2)	3.6	(19.7)	4.8	4.9	4.9	4.9	4.9	4.9
CCG	(4.6)	(5.3)	(4.9)	(3.8)	(5.4)	(5.5)	(6.3)	(6.0)	(6.2)	(6.6)	(8.7)	(7.3)	(7.0)	(7.0)	(8.2)	(7.0)	(7.0)	(7.3)	(7.3)	(7.2)	(7.2)	(7.2)	(7.1)
Net emissions based on the IPCC Tier 2 analysis (Step 3)																							
Mineral Soils																							
CRC	(6.5)	(6.5)	(6.5)	(7.6)	(7.6)	(7.6)	(7.6)	(7.6)	(6.9)	(6.9)	(6.9)	(6.9)	(6.9)	(2.8)	(2.8)	(2.8)	(2.8)	(2.8)	(2.8)	(2.8)	(2.8)	(2.8)	(2.8)
GCC	2.3	2.3	2.3	2.0	2.0	2.0	2.0	2.0	1.8	1.8	1.8	1.8	1.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
FCC	1.5	1.5	1.5	1.4	1.4	1.4	1.4	1.4	0.8	0.8	0.8	0.8	0.8	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
OCC	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
SCC	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
WCC	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
GRG	(0.2)	(0.2)	(0.2)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
CCG	(1.7)	(1.7)	(1.7)	(1.6)	(1.6)	(1.6)	(1.6)	(1.6)	(1.7)	(1.7)	(1.7)	(1.7)	(1.7)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)
FCG	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)
OCG	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
SCG	(0.4)	(0.4)	(0.4)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)
WCG	(0.1)	(0.1)	(0.1)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Organic Soils																							
CRC	24.0	23.7	23.7	23.0	22.4	22.2	21.8	21.7	21.7	21.6	21.5	22.0	21.9	22.9	22.6	22.4	22.3	22.1	22.1	22.1	22.1	22.1	22.1
GCC	2.5	2.6	2.4	2.7	3.1	3.1	3.3	3.3	3.4	3.3	3.3	4.7	4.3	4.0	4.4	4.3	4.2	4.0	4.0	4.0	4.0	4.0	4.0
FCC	(0.2)	(0.2)	0.8	0.8	0.9	0.8	0.9	0.9	0.8	0.8	0.7	0.4	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2
OCC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SCC	(0.0)	(0.0)	0.1	0.2	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
WCC	(0.2)	(0.2)	0.6	0.7	0.8	0.8	0.8	0.8	0.9	0.7	0.6	0.6	0.5	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4
GRG	4.6	4.5	4.5	4.4	4.3	4.1	4.0	3.9	3.8	3.7	3.7	3.3	3.2	3.1	3.1	3.1	3.0	3.0	3.0	3.0	3.0	3.0	3.0
CCG	0.5	0.5	0.5	0.6	0.7	0.7	0.7	0.7	0.9	0.9	0.9	0.9	1.1	0.9	1.0	1.0	1.0	0.9	0.9	0.9	0.9	0.9	0.9
FCG	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
OCG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SCG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WCG	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Additional changes in net emissions from mineral soils based on application of sewage sludge to agricultural land (Step 4)																							
GRG	(0.6)	(0.6)	(0.7)	(0.7)	(0.8)	(0.8)	(0.8)	(0.9)	(0.9)	(0.9)	(1.0)	(1.0)	(1.0)	(1.0)	(1.1)	(1.1)	(1.2)	(1.2)	(1.2)	(1.2)	(1.3)	(1.3)	(1.3)
Additional changes in net emissions from mineral soils based on additional enrollment of CRP land (Step 4)																							
CRC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.4	2.0	3.6	3.7	4.8
Total Stock Changes by Land Use/Land-Use Change Category (Step 5)																							
CRC	(51.9)	(57.2)	(49.0)	(30.3)	(38.2)	(27.3)	(37.3)	(32.7)	(23.5)	(26.6)	(42.7)	(30.2)	(22.9)	(15.6)	(19.2)	(29.1)	(31.4)	(31.3)	(29.8)	(29.2)	(27.6)	(27.5)	(26.5)
GCC	24.8	22.2	23.9	24.9	17.4	25.4	21.5	21.9	17.1	17.2	17.0	19.8	18.6	17.7	15.7	19.3	15.9	15.3	15.3	15.3	15.3	15.3	15.3
FCC	1.2	1.2	2.2	2.2	2.2	2.2	2.3	2.3	1.7	1.6	1.5	1.2	1.1	0.5	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
OCC	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
SCC	0.5	0.5	0.6	0.9	1.1	1.1	1.1	1.1	1.0	1.0	0.9	0.9	0.9	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
WCC	0.0	(0.0)	0.8	0.9	1.0	1.0	1.1	1.1	1.1	0.9	0.8	0.8	0.7	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
GRG	(9.6)	1.1	(7.7)	3.0	(14.6)	5.0	(18.4)	(5.5)	(6.8)	3.3	(30.7)	(9.2)	(12.5)	(8.3)	1.9	5.6	(17.8)	6.8	6.8	6.8	6.7	6.7	6.7
CCG	(5.8)	(6.5)	(6.0)	(4.8)	(6.2)	(6.4)	(7.2)	(6.8)	(7.0)	(7.5)	(9.5)	(8.1)	(7.7)	(7.3)	(8.4)	(7.3)	(7.3)	(7.7)	(7.7)	(7.6)	(7.6)	(7.5)	(7.5)

FCG	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(0.7)	(0.7)	(0.7)	(0.7)	(0.7)	(0.4)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
OCG	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
SCG	(0.4)	(0.4)	(0.4)	(0.5)	(0.5)	(0.5)	(0.5)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)
WCG	(0.0)	(0.0)	(0.0)	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Total *	**(41.9)**	**(39.9)**	**(36.5)**	**(4.7)**	**(38.8)**	**(0.4)**	**(38.4)**	**(20.1)**	**(17.8)**	**(11.3)**	**(64.1)**	**(26.0)**	**(23.1)**	**(13.0)**	**(9.4)**	**(11.0)**	**(40.2)**	**(16.4)**	**(14.9)**	**(14.3)**	**(12.7)**	**(12.5)**	**(11.4)**

Note: Totals may not sum due to independent rounding.

Table A- 243: Total 2012 N_2O Emissions (Direct and Indirect) from Agricultural Soil Management by State (Tg CO_2 Eq.)

State	Croplands[a]	Grasslands[b]	Settlements[c]	Forest Lands[d]	Total	Lower Bound	Upper Bound
AL	1.19	0.88	0.03	NE	2.14	1.39	3.77
AR	4.20	1.40	0.02	NE	5.70	4.24	8.44
AZ	0.98	1.30	0.01	NE	2.35	1.34	4.34
CA	7.51	2.17	0.18	NE	10.35	3.63	21.08
CO	4.08	6.10	0.02	NE	10.24	7.16	15.15
CT	0.21	0.04	0.02	NE	0.27	0.21	0.42
DE	0.24	0.01	0.01	NE	0.27	0.19	1.12
FL	4.91	1.59	0.21	NE	6.97	2.85	14.02
GA	1.58	0.60	0.01	NE	2.25	1.25	4.41
HI[e]	0.03	n.e.	n.e.	NE	0.03	0.01	0.11
IA	16.46	2.23	0.07	NE	18.76	14.46	25.47
ID	4.00	2.96	0.02	NE	7.05	5.33	10.13
IL	14.94	1.44	0.11	NE	16.51	12.92	22.07
IN	7.65	2.71	0.07	NE	10.45	7.16	15.52
KS	12.26	4.63	0.06	NE	16.98	13.22	22.74
KY	2.40	2.20	0.03	NE	4.66	3.23	7.13
LA	1.32	0.89	0.04	NE	2.25	1.54	3.82
MA	0.38	0.06	0.04	NE	0.49	0.37	1.36
MD	0.59	0.19	0.05	NE	0.85	0.57	1.92
ME	0.68	0.14	0.01	NE	0.84	0.60	1.79
MI	5.08	1.31	0.08	NE	6.56	4.90	9.60
MN	9.96	1.48	0.03	NE	11.53	9.18	15.90
MO	7.67	6.07	0.07	NE	13.82	10.85	18.75
MS	2.80	0.74	0.03	NE	3.59	2.73	5.50
MT	5.64	10.59	0.01	NE	16.24	11.97	22.52
NC	2.13	0.56	0.05	NE	2.85	1.23	5.88
ND	7.57	1.83	0.03	NE	9.43	7.39	12.44
NE	8.62	5.45	0.06	NE	14.16	7.10	24.40
NH	0.22	0.04	0.01	NE	0.27	0.19	1.17
NJ	0.38	0.07	0.07	NE	0.54	0.28	1.52
NM	1.82	3.10	0.01	NE	5.00	3.09	8.33
NV	0.33	1.12	0.01	NE	1.47	0.97	2.73
NY	6.01	1.82	0.07	NE	7.94	6.37	10.79
OH	6.40	1.18	0.10	NE	7.89	5.02	12.59
OK	3.19	5.79	0.03	NE	9.14	6.34	13.53
OR	2.10	3.90	0.01	NE	6.04	4.73	8.25
PA	4.96	0.93	0.06	NE	6.03	4.54	9.42
RI	0.02	0.01	0.01	NE	0.04	0.02	0.84
SC	0.68	0.29	0.03	NE	1.02	0.65	2.18
SD	6.66	4.70	0.02	NE	11.38	8.45	15.26
TN	1.60	1.33	0.05	NE	3.00	1.98	4.97
TX	9.06	14.01	0.09	NE	23.26	16.07	33.96
UT	0.99	1.73	0.01	NE	2.75	1.97	4.40
VA	0.88	1.47	0.05	NE	2.43	1.35	4.56
VT	1.22	0.28	0.00	NE	1.50	1.19	22.27
WA	3.72	2.57	0.03	NE	6.39	4.83	9.05
WI	4.40	1.58	0.04	NE	6.12	4.41	10.37
WV	0.56	0.47	0.00	NE	1.06	0.57	2.39
WY	1.13	4.51	0.01	NE	5.68	1.86	1.90

[a] Emissions from non-manure organic N inputs for minor crops were not estimated (n.e.) at the state level.

[b] Emissions from sewage sludge applied to grasslands and were not estimated (n.e.) at the state level

[c] Emissions from sewage sludge applied to settlements were not estimated (n.e.) at the state level.

[d] Forestland emissions were not estimated (n.e.) at the state level.

[e] N_2O emissions are not reported for Hawaii except from cropland organic soils.

Table A- 244: Soil C Stock Change for Mineral and Organic Soils during 2012 within individual states (Tg CO_2 Eq.)

State	Mineral Soil	Organic Soil	Total
AL	(1.31)	-	(1.31)
AR	(0.17)	-	(0.17)
AZ	0.20	-	0.20
CA	(0.94)	1.55	0.61
CO	0.16	0.00	0.17
CT	(0.05)	0.00	(0.04)
DE	(0.12)	0.01	(0.11)
FL	0.28	10.11	10.39
GA	(0.67)	-	(0.67)
HI	(0.02)	0.25	0.24
IA	(8.59)	0.54	(8.05)
ID	(1.07)	0.08	(0.98)
IL	(5.00)	0.62	(4.38)
IN	(1.71)	2.37	0.67
KS	(2.99)	-	(2.99)
KY	(1.82)	-	(1.82)
LA	(1.45)	0.33	(1.11)
MA	(0.07)	0.12	0.05
MD	(0.37)	0.02	(0.34)
ME	(0.22)	0.00	(0.21)
MI	(0.75)	3.05	2.29
MN	(2.07)	5.85	3.78
MO	(2.47)	-	(2.47)
MS	(1.03)	0.00	(1.03)
MT	1.72	0.16	1.87
NC	(1.21)	1.90	0.68
ND	(1.63)	-	(1.63)
NE	(0.52)	0.00	(0.52)
NH	(0.03)	0.05	0.02
NJ	(0.15)	0.06	(0.10)
NM	1.13	-	1.13
NV	(0.12)	0.00	(0.12)
NY	0.19	0.41	0.61
OH	(2.11)	0.47	(1.64)
OK	(0.26)	-	(0.26)
OR	(1.71)	0.34	(1.38)
PA	(0.84)	0.02	(0.82)
RI	(0.01)	0.02	0.01
SC	(0.64)	0.02	(0.62)
SD	(0.68)	-	(0.68)
TN	(2.14)	-	(2.14)
TX	0.07	-	0.07
UT	0.48	0.08	0.56
VA	(1.23)	0.00	(1.23)
VT	(0.02)	0.06	0.03
WA	(1.10)	0.31	(0.79)
WI	0.48	2.28	2.76
WV	(0.59)	-	(0.59)
WY	0.93	-	0.93

Note: Parentheses indicate net C accumulation. Estimates do not include soil C stock change associated with CRP enrollment after 2007 or sewage sludge application to soils, which were only estimated at the national scale. The sum of state results will not match the national results because state results are generated in a separate programming package, the sewage sludge and CRP enrollment after 2007 are not included, and differences arise due to rounding of values in this table.

3.13. Methodology for Estimating Net Carbon Stock Changes in Forest Lands Remaining Forest Lands

This sub-annex expands on the methodology used to estimate net changes in carbon (C) stocks in forest ecosystems and in harvested wood products. Some of the details of C conversion factors and procedures for calculating net CO_2 flux for forests are provided below; full details of selected topics may be found in the cited references.

Carbon Stocks and Net Changes in Forest Ecosystem Carbon Stocks

At least two forest inventories exist for most forest land in the United States. Carbon stocks are estimated based on data from each inventory, at the level of permanent inventory plots. Carbon per hectare (for a sample location) is multiplied by the total number of hectares that the plot represents, and then totals are summed for an area of interest, such as the state of Maine. Net annual C stock changes are calculated by taking the difference between the inventories and dividing by the number of years between the inventories for a selected state or sub-state area.

Forest inventory data

The estimates of forest C stocks are based on data from forest inventory surveys. Forest inventory data were obtained from the USDA Forest Service, Forest Inventory and Analysis (FIA) program (Frayer and Furnival 1999, USDA Forest Service 2013a, USDA Forest Service 2013b). Forest Inventory and Analysis data include remote sensing information and collection of measurements in the field at sample locations called plots. Tree measurements include diameter and species. On a subset of plots, additional measurements or samples are taken of downed dead wood, litter, and soil C. However, the technical advances needed to estimate C stocks from these data are still under development (e.g., forest floor, Woodall et al. 2012). The field protocols are thoroughly documented and available for download from the USDA Forest Service (2013c). Bechtold and Patterson (2005) provide the estimation procedures for standard forest inventory results. The data are freely available for download at USDA Forest Service (2011b) as the Forest Inventory and Analysis Database (FIADB) Version 5.1.6 (USDA Forest Service 2013b, USDA Forest Service 2013c); these data are the primary sources of forest inventory used to estimate forest C stocks.

Forest surveys have begun in the U.S. territories and in Hawaii. Meanwhile this inventory assumes that these areas account for a net C change of zero. Survey data are available for the temperate oceanic ecoregion of Alaska (southeast and south central). Inventory data are publicly available for 6 million hectares of forest land, and these inventoried lands, comprising an estimated 12 percent of the total forest land in Alaska, contribute to the forest C stocks presented here.

Agroforestry systems are also not currently accounted for in the U.S. inventory, since they are not explicitly inventoried by either of the two primary national natural resource inventory programs: the FIA program of the USDA Forest Service and the National Resources Inventory (NRI) of the USDA Natural Resources Conservation Service (Perry et al. 2005). The majority of these tree-based practices do not meet the size and definitions for forests within each of these resource inventories. The size characteristics that exclude them from inventories also allow these systems to provide their many services without taking the land out of agricultural production, making them an appealing C sequestration option. Agroforestry in the United States has been defined as "intensive land-use management that optimizes the benefits (physical, biological, ecological, economic, social) from bio-physical interactions created when trees and/or shrubs are deliberately combined with crops and/or livestock" (Gold et al. 2000). In the United States, there are six categories of agroforestry practices: riparian forest buffers, windbreaks, alley cropping, silvopasture, forest farming and special applications.[94] These practices are used to address many issues facing agricultural lands, such as economic diversification, habitat fragmentation, and water quality. While providing these services and regardless of intent, these tree-based plantings will also help reduce atmospheric CO_2. This occurs directly through CO_2 sequestration into woody biomass, and indirectly through enhancement of agricultural production, trapping wind-blown and surface runoff sediments, and/or reducing CO_2 emissions through fuel-use savings (Quam et al. 1992). The effects of these individual practices can potentially be quite large when taken into account within a whole-farm or within an aggregating larger entity (i.e., state-level) (Quam et al. 1992, Schoeneberger 2006). One estimate of the sequestration potential through agroforestry practices in the United States is 90.3 Mt C/year by 2025 (Nair and Nair 2003).

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[94] More information on agroforestry practices can be found online at <http://www.unl.edu/nac>.

Summing state-level C stocks to calculate United States net C flux in forest ecosystems

The overall approach for determining forest C stocks and stock change is essentially based on methodology and algorithms coded into the computer tool described in Smith et al. (2010). A recent change in methods for the inventory involves a modification of the downed dead wood estimates to incorporate population estimates of down woody material measured on a subset of the inventory plots (Domke et al. 2013, Woodall and Monleon 2008, Woodall et al. 2013). The C calculation tool focuses on estimating forest C stocks based on data from two or more forest surveys conducted several years apart for each state or sub-state. There are generally two or more surveys available for download for each state. Carbon stocks are calculated separately for each state based on available inventories conducted since 1990 and for the inventory closest to, but prior to, 1990 if such data are available and consistent with these methods. This approach ensures that the period 1990 (the base year) to present can be adequately represented. Surveys conducted prior to and in the early to mid-1990s focused on land capable of supporting timber production (timberland).[95] As a result, information on less productive forest land or lands reserved from harvest was limited. Inventory field crews periodically measured all the plots in a state at a frequency of every 5 to 14 years. Generally, forests in states with fast-growing (and therefore rapidly changing) forests tended to be surveyed more often than states with slower-growing (and therefore slowly changing) forests. Older surveys for some states, particularly in the West, also have National Forest System (NFS) lands or reserved lands that were surveyed at different times than productive, privately-owned forest land in the state. Periodic data for each state thus became available at irregular intervals and determining the year of data collection associated with the survey can sometimes be difficult.

Table A-245: Source of Unique Forest Inventory and Average Year of Field Survey Used to Estimate Statewide Carbon Stocks

State/Substate[a]	Source of Inventory Data, Report/Inventory Year[b]	Average Year Assigned to Inventory[c]
Alabama	FIADB 5.1.6, 1982	1982
	FIADB 5.1.6, 1990	1990
	FIADB 5.1.6, 2000	1999
	FIADB 5.1.6, 2005	2003
	FIADB 5.1.6, 2012	2009
Alaska, Coastal east non-reserved	FIADB 5.1.6, 2003	1997
	FIADB 5.1.6, 2011	2008
Alaska, Coastal reserved	FIADB 5.1.6, 2011	2006
Alaska, Coastal west non-reserved	FIADB 5.1.6, 2003	2001
	FIADB 5.1.6, 2011	2008
Arizona, NFS non-woodlands	1987 RPA	1985
	FIADB 5.1.6, 1999	1996
	FIADB 5.1.6, 2010	2006
Arizona, NFS woodlands	1987 RPA	1984

Forest land is defined as land at least 120 feet wide and 1 acre in size with at least 10 percent cover (or equivalent stocking by live trees of any size, including land that formerly had such tree cover and that will be naturally or artificially regenerated. Forest land includes transition zones, such as areas between forest and nonforest lands that have at least 10 percent cover (or equivalent stocking) with live trees and forest areas adjacent to urban and built-up lands. Roadside, streamside, and shelterbelt strips of trees must have a crown width of at least 120 feet and continuous length of at least 363 feet to qualify as forest land. Unimproved roads and trails, streams, and clearings in forest areas are classified as forest if they are less than 120 feet wide or an acre in size. Tree-covered areas in agricultural production settings, such as fruit orchards, or tree-covered areas in urban settings, such as city parks, are not considered forest land (Smith et al. 2009). Timberland is the most productive type of forest land, which is on unreserved land and is producing or capable of producing crops of industrial wood. Productivity is at a minimum rate of 20 cubic feet of industrial wood per acre per year (Woudenberg and Farrenkopf 1995). There are about 203 million hectares of timberland in the conterminous United States, which represents 81 percent of all forest lands over the same area (Smith et al. 2009).

	FIADB 5.1.6, 1999	1996
	FIADB 5.1.6, 2010	2006
Arizona, non-NFS non-woodlands	FIADB 5.1.6, 1985	1986
	FIADB 5.1.6, 1999	1996
	FIADB 5.1.6, 2010	2007
Arizona, non-NFS woodlands	FIADB 5.1.6, 1999	1990
	FIADB 5.1.6, 2010	2006
Arkansas	FIADB 5.1.6, 1988	1988
	FIADB 5.1.6, 1995	1996
	FIADB 5.1.6, 2005	2003
	FIADB 5.1.6, 2010	2008
California, NFS	IDB, 1990s	1997
	FIADB 5.1.6, 2010	2006
California, non-NFS	IDB, 1990s	1993
	FIADB 5.1.6, 2010	2006
Colorado, NFS non-woodlands	1997 RPA	1981
	FIADB 5.1.6, 2011	2007
Colorado, NFS woodlands	FIADB 5.1.6, 2011	2007
Colorado, non-NFS non-woodlands	Westwide, 1983	1980
	FIADB 5.1.6, 2011	2007
Colorado, non-NFS woodlands	Westwide, 1983	1983
	FIADB 5.1.6, 2011	2007
Connecticut	FIADB 5.1.6, 1985	1985
	FIADB 5.1.6, 1998	1998
	FIADB 5.1.6, 2007	2006
	FIADB 5.1.6, 2011	2010
Delaware	FIADB 5.1.6, 1986	1986
	FIADB 5.1.6, 1999	1999
	FIADB 5.1.6, 2008	2007
	FIADB 5.1.6, 2011	2010
Florida	FIADB 5.1.6, 1987	1987
	FIADB 5.1.6, 1995	1995
	FIADB 5.1.6, 2007	2005
	FIADB 5.1.6, 2011	2009
Georgia	FIADB 5.1.6, 1989	1989
	FIADB 5.1.6, 1997	1997
	FIADB 5.1.6, 2004	2002
	FIADB 5.1.6, 2009	2007
	FIADB 5.1.6, 2012	2010
Idaho, Caribou-Targhee NF	Westwide, 1991	1992
	FIADB 5.1.6, 2011	2008
Idaho, Kootenai NF	1987 RPA	1988
	FIADB 5.1.6, 1991	1995
	FIADB 5.1.6, 2011	2008
Idaho, Payette NF	1987 RPA	1982
	FIADB 5.1.6, 2011	2008
Idaho, Salmon-Challis NF	1987 RPA	1978
	FIADB 5.1.6, 2011	2008

Idaho, Sawtooth NF	Westwide, 1991	1983
	FIADB 5.1.6, 1991	1996
	FIADB 5.1.6, 2011	2008
Idaho, non-NFS non-woodlands	FIADB 5.1.6, 1991	1990
	FIADB 5.1.6, 2011	2008
Idaho, non-NFS woodlands	FIADB 5.1.6, 1991	1982
	FIADB 5.1.6, 2011	2008
Idaho, other NFS	Westwide, 1991	1988
	FIADB 5.1.6, 1991	2000
	FIADB 5.1.6, 2011	2008
Illinois	FIADB 5.1.6, 1985	1985
	FIADB 5.1.6, 1998	1998
	FIADB 5.1.6, 2005	2004
	FIADB 5.1.6, 2010	2008
Indiana	FIADB 5.1.6, 1986	1986
	FIADB 5.1.6, 1998	1998
	FIADB 5.1.6, 2003	2001
	FIADB 5.1.6, 2008	2007
	FIADB 5.1.6, 2012	2010
Iowa	FIADB 5.1.6, 1990	1990
	FIADB 5.1.6, 2003	2002
	FIADB 5.1.6, 2008	2006
	FIADB 5.1.6, 2012	2010
Kansas	FIADB 5.1.6, 1981	1981
	FIADB 5.1.6, 1994	1994
	FIADB 5.1.6, 2005	2003
	FIADB 5.1.6, 2010	2009
Kentucky	FIADB 5.1.6, 1988	1987
	FIADB 5.1.6, 2004	2002
	FIADB 5.1.6, 2009	2008
Louisiana	FIADB 5.1.6, 1984	1984
	FIADB 5.1.6, 1991	1991
	FIADB 5.1.6, 2005	2004
Maine	Eastwide, 1982	1983
	FIADB 5.1.6, 1995	1995
	FIADB 5.1.6, 2003	2002
	FIADB 5.1.6, 2008	2007
	FIADB 5.1.6, 2012	2010
Maryland	FIADB 5.1.6, 1986	1986
	FIADB 5.1.6, 1999	2000
	FIADB 5.1.6, 2008	2007
	FIADB 5.1.6, 2011	2010
Massachusetts	FIADB 5.1.6, 1985	1985
	FIADB 5.1.6, 1998	1998
	FIADB 5.1.6, 2007	2006
	FIADB 5.1.6, 2011	2010
Michigan	FIADB 5.1.6, 1980	1980

	FIADB 5.1.6, 1993	1993
	FIADB 5.1.6, 2004	2003
	FIADB 5.1.6, 2009	2007
	FIADB 5.1.6, 2012	2010
Minnesota	FIADB 5.1.6, 1990	1989
	FIADB 5.1.6, 2003	2001
	FIADB 5.1.6, 2008	2006
	FIADB 5.1.6, 2012	2010
Mississippi	FIADB 5.1.6, 1987	1987
	FIADB 5.1.6, 1994	1994
	FIADB 5.1.6, 2006	2007
	FIADB 5.1.6, 2012	2009
Missouri	FIADB 5.1.6, 1989	1988
	FIADB 5.1.6, 2003	2002
	FIADB 5.1.6, 2008	2006
	FIADB 5.1.6, 2012	2010
Montana, NFS	1987 RPA	1988
	FIADB 5.1.6, 1989	1996
	FIADB 5.1.6, 2011	2008
Montana, non-NFS non-reserved	FIADB 5.1.6, 1989	1989
	FIADB 5.1.6, 2011	2008
Montana, non-NFS reserved	1997 RPA	1990
	FIADB 5.1.6, 2011	2008
Nebraska	FIADB 5.1.6, 1983	1983
	FIADB 5.1.6, 1994	1995
	FIADB 5.1.6, 2005	2004
	FIADB 5.1.6, 2010	2008
Nevada, NFS non-woodlands	1987 RPA	1974
	FIADB 5.1.6, 1989	1997
	FIADB 5.1.6, 2005	2005
Nevada, NFS woodlands	1987 RPA	1978
	FIADB 5.1.6, 1989	1997
	FIADB 5.1.6, 2005	2005
Nevada, non-NFS non-woodlands	1997 RPA	1985
	FIADB 5.1.6, 2005	2005
Nevada, non-NFS woodlands	FIADB 5.1.6, 1989	1980
	FIADB 5.1.6, 2005	2005
New Hampshire	FIADB 5.1.6, 1983	1983
	FIADB 5.1.6, 1997	1997
	FIADB 5.1.6, 2007	2005
	FIADB 5.1.6, 2012	2011
New Jersey	FIADB 5.1.6, 1987	1987
	FIADB 5.1.6, 1999	1999
	FIADB 5.1.6, 2008	2007
	FIADB 5.1.6, 2011	2010
New Mexico, NFS non-woodlands	1987 RPA	1986
	FIADB 5.1.6, 1999	1997
	FIADB 5.1.6, 2012	2011

New Mexico, NFS woodlands	1987 RPA	1986
	FIADB 5.1.6, 1999	1997
	FIADB 5.1.6, 2012	2011
New Mexico, non-NFS non-timberlands	FIADB 5.1.6, 2012	2011
New Mexico, non-NFS timberlands	FIADB 5.1.6, 1987	1987
	FIADB 5.1.6, 1999	1999
	FIADB 5.1.6, 2012	2011
New York, non-reserved	Eastwide, 1980	1981
	FIADB 5.1.6, 1993	1993
	FIADB 5.1.6, 2007	2005
	FIADB 5.1.6, 2011	2010
New York, reserved	1987 RPA	1988
	FIADB 5.1.6, 2007	2005
	FIADB 5.1.6, 2011	2010
North Carolina	FIADB 5.1.6, 1984	1984
	FIADB 5.1.6, 1990	1990
	FIADB 5.1.6, 2002	2001
	FIADB 5.1.6, 2007	2006
	FIADB 5.1.6, 2012	2009
North Dakota	FIADB 5.1.6, 1980	1979
	FIADB 5.1.6, 1995	1995
	FIADB 5.1.6, 2005	2003
	FIADB 5.1.6, 2010	2009
Ohio	FIADB 5.1.6, 1991	1991
	FIADB 5.1.6, 2006	2005
	FIADB 5.1.6, 2011	2010
Oklahoma, Central & West	FIADB 5.1.6, 2011	2011
Oklahoma, East	FIADB 5.1.6, 1986	1986
	FIADB 5.1.6, 1993	1993
	FIADB 5.1.6, 2008	2008
Oregon, NFS East	IDB, 1990s	1995
	FIADB 5.1.6, 2010	2006
Oregon, NFS West	IDB, 1990s	1996
	FIADB 5.1.6, 2010	2006
Oregon, non-NFS East	Westwide, 1992	1991
	IDB, 1990s	1999
	FIADB 5.1.6, 2010	2006
Oregon, non-NFS West	Westwide, 1992	1989
	IDB, 1990s	1997
	FIADB 5.1.6, 2010	2006
Pennsylvania	FIADB 5.1.6, 1989	1990
	FIADB 5.1.6, 2004	2003
	FIADB 5.1.6, 2009	2008
Rhode Island	FIADB 5.1.6, 1985	1985
	FIADB 5.1.6, 1998	1999
	FIADB 5.1.6, 2007	2006
	FIADB 5.1.6, 2011	2010

South Carolina	FIADB 5.1.6, 1986	1986
	FIADB 5.1.6, 1993	1993
	FIADB 5.1.6, 2001	2001
	FIADB 5.1.6, 2006	2005
	FIADB 5.1.6, 2011	2009
South Dakota, NFS	1997 RPA	1986
	FIADB 5.1.6, 1995	1999
	FIADB 5.1.6, 2005	2004
	FIADB 5.1.6, 2010	2009
South Dakota, non-NFS	1987 RPA	1986
	FIADB 5.1.6, 1995	1995
	FIADB 5.1.6, 2005	2004
	FIADB 5.1.6, 2010	2008
Tennessee	FIADB 5.1.6, 1989	1989
	FIADB 5.1.6, 1999	1998
	FIADB 5.1.6, 2004	2003
	FIADB 5.1.6, 2009	2008
Texas, Central & West	FIADB 5.1.6, 2010	2008
Texas, East	FIADB 5.1.6, 1986	1986
	FIADB 5.1.6, 1992	1992
	FIADB 5.1.6, 2003	2003
	FIADB 5.1.6, 2008	2006
	FIADB 5.1.6, 2012	2010
Utah, non-woodlands	FIADB 5.1.6, 1993	1993
	FIADB 5.1.6, 2009	2005
Utah, woodlands	FIADB 5.1.6, 1993	1994
	FIADB 5.1.6, 2009	2005
Vermont	FIADB 5.1.6, 1983	1983
	FIADB 5.1.6, 1997	1997
	FIADB 5.1.6, 2007	2006
	FIADB 5.1.6, 2011	2010
Virginia	FIADB 5.1.6, 1985	1985
	FIADB 5.1.6, 1992	1991
	FIADB 5.1.6, 2001	2000
	FIADB 5.1.6, 2007	2005
	FIADB 5.1.6, 2011	2010
Washington, NFS East	IDB, 1990s	1996
	FIADB 5.1.6, 2011	2007
Washington, NFS West	IDB, 1990s	1996
	FIADB 5.1.6, 2011	2007
Washington, non-NFS East	IDB, 1990s	1992
	FIADB 5.1.6, 2011	2007
Washington, non-NFS West	IDB, 1990s	1990
	FIADB 5.1.6, 2011	2007
West Virginia	FIADB 5.1.6, 1989	1988
	FIADB 5.1.6, 2000	2001
	FIADB 5.1.6, 2008	2007
	FIADB 5.1.6, 2011	2010

Wisconsin	FIADB 5.1.6, 1983	1982
	FIADB 5.1.6, 1996	1995
	FIADB 5.1.6, 2004	2002
	FIADB 5.1.6, 2009	2007
	FIADB 5.1.6, 2012	2010
Wyoming, NFS	1997 RPA	1982
	FIADB 5.1.6, 2000	2000
Wyoming, non-NFS non-reserved non-woodlands	FIADB 5.1.6, 1984	1984
	FIADB 5.1.6, 2000	2002
Wyoming, non-NFS non-reserved woodlands	FIADB 5.1.6, 1984	1984
	FIADB 5.1.6, 2000	2002
Wyoming, non-NFS reserved	1997 RPA	1985
	FIADB 5.1.6, 2000	2000

[a] Substate areas (Smith et al. 2010) include National Forests (NFS), all forest ownerships except National Forest (non-NFS), woodlands (forest land dominated by woodland species, such as pinyon and juniper, where stocking cannot be determined (USDA Forest Service 2013c), non-woodlands (used for clarity to emphasize that woodlands are classified separately), reserved (forest land withdrawn from timber utilization through statute, administrative regulation, or designation, Smith et al. (2009)), and non-reserved (forest land that is not reserved, used for clarity). Some National Forests are listed individually by name, e.g., Payette NF. Oregon and Washington were divided into eastern and western forests (east or west of the crest of the Cascade Mountains). Oklahoma and Texas are divided into East versus Central & West according to forest inventory survey units (USDA Forest Service 2013d). Alaska is represented by a portion of forest land, in the southcentral and southeast part of the state.

[b] FIADB 5.1.6 is the current, publicly available, format of FIA inventory data, and these files were downloaded from the Internet 11 July 2013 (USDA Forest Service 2013b). IDB (Integrated Database) data are a compilation of periodic inventory data from the 1990s for California, Oregon, and Washington (Waddell and Hiserote 2005). Eastwide (Hansen et al. 1992) and Westwide (Woudenberg and Farrenkopf 1995) inventory data are formats that predate the FIADB data. RPA data are periodic national summaries. The year is the nominal, or reporting, year associated with each dataset.

[c] Average year is based on average measurement year of forest land survey plots and rounded to the nearest integer year.

A national plot design and annualized sampling (USDA Forest Service 2013a) was introduced by FIA with most new surveys beginning after 1998. These surveys include sampling of all forest land including reserved and lower productivity lands. Most states have annualized inventory data available as of July 2013. Annualized sampling means that a portion of plots throughout the state is sampled each year, with the goal of measuring all plots once every 5 to 10 years, depending on the region of the United States. The full unique set of data with all measured plots, such that each plot has been measured one time, is called a cycle. Sampling is designed such that partial inventory cycles provide usable, unbiased samples of forest inventory, but with higher sampling errors than the full cycle. After all plots have been measured once, the sequence continues with remeasurement of the first year's plots, starting the next new cycle. Most Eastern states have completed one or two cycles of the annualized inventories and are providing annual updates to the state's forest inventory with each year's remeasurements, such that one plot's measurements are included in subsequent year's annual updates. Thus, annually updated estimates of forest C stocks are accurate, but estimates of stock change cannot utilize the annually updated inventory measurements directly, as there is redundancy in the data used to generate the annual updates of C stock. For example, a typical annual inventory update for an Eastern state will include new data from remeasurement on 20 percent of plots; data from the remaining 80 percent of plots is identical to that included in the previous year's annual update. The interpretation and use of the sequence of annual inventory updates can affect trends in annualized stock and stock change. In general, the C stock and stock change calculations use annual inventory summaries (updates) with unique sets of plot-level data (that is, without redundant sets); the most-recent annual update is the exception because it is included in stock change calculations if at least half of the plots in a state include new measurements. The specific surveys used in this report are listed in Table A-245, and this list can be compared with the full set of summaries available for download (USDA Forest Service 2013b).

For each pool in each state in each year, C stocks are estimated by linear interpolation between survey years. Similarly, fluxes, or net stock changes, are estimated for each pool in each state by dividing the difference between two successive stocks by the number of intervening years between surveys. Thus, the number of separate stock change estimates for each state or sub-state is one less than the number of available inventories. Annual estimates of stock and net change since the most recent survey are based on linear extrapolation. Carbon stock and flux estimates for each pool are summed over all forest land in all states as identified in the FIADB to form estimates for the United States. Summed net annual stock change and stocks are presented in Table A-245 and Table A-246 , respectively. An estimate of forest area based on the interpolation and extrapolation procedure described above is also provided in Table A-247. Estimated net stock change of non-soil forest ecosystem carbon for each of the states is shown in Table A-248, which also includes estimated forest area and total non-soil forest C stock. The state-level forest areas and C stocks are from the most recent inventory available (USDA Forest Service 2011a), and the estimate for net stock change is the 10-year mean of the 2003 through 2012 estimates from the C calculator (Smith et al. 2010).

Table A-246: Estimated Net Annual Changes in Carbon Stocks (Tg C yr^{-1}) in Forest and Harvested Wood Pools, 1990–2012

Year	Total Net Flux	Forest Total	Live, aboveground	Live, belowground	Dead Wood	Litter	Soil Organic Carbon	Harvested Wood Total	Products in Use	SWDS
1990	(192.2)	(156.2)	(96.7)	(18.9)	(13.8)	(6.5)	(20.3)	(35.9)	(17.7)	(18.3)
1991	(189.8)	(156.0)	(96.6)	(18.9)	(14.0)	(6.5)	(20.1)	(33.8)	(14.9)	(18.8)
1992	(188.3)	(154.5)	(97.5)	(19.1)	(14.1)	(6.5)	(17.3)	(33.8)	(16.3)	(17.4)
1993	(188.9)	(155.9)	(103.4)	(20.3)	(14.9)	(5.6)	(11.7)	(32.9)	(15.0)	(17.9)
1994	(195.6)	(162.2)	(106.5)	(20.9)	(14.9)	(5.1)	(14.8)	(33.4)	(15.9)	(17.5)
1995	(197.0)	(164.7)	(109.7)	(21.6)	(14.2)	(3.4)	(15.8)	(32.3)	(15.1)	(17.2)
1996	(193.3)	(162.7)	(109.1)	(21.5)	(19.9)	(2.5)	(9.6)	(30.6)	(14.1)	(16.5)
1997	(184.3)	(152.3)	(110.1)	(21.7)	(18.6)	(2.3)	0.4	(32.0)	(14.7)	(17.3)
1998	(169.5)	(138.3)	(105.2)	(20.7)	(18.6)	1.7	4.6	(31.1)	(13.4)	(17.7)
1999	(152.7)	(120.2)	(101.2)	(20.0)	(18.2)	5.0	14.2	(32.5)	(14.1)	(18.4)
2000	(147.1)	(116.3)	(100.3)	(19.8)	(18.6)	6.8	15.5	(30.8)	(12.8)	(18.0)
2001	(175.2)	(149.7)	(109.4)	(21.6)	(19.0)	1.5	(1.2)	(25.5)	(8.7)	(16.8)
2002	(210.8)	(184.0)	(112.0)	(22.0)	(20.2)	(5.1)	(24.6)	(26.8)	(9.6)	(17.2)
2003	(240.3)	(214.7)	(118.5)	(23.3)	(19.3)	(9.4)	(44.3)	(25.6)	(9.4)	(16.2)
2004	(250.4)	(222.0)	(120.3)	(23.7)	(18.7)	(11.1)	(48.2)	(28.3)	(12.0)	(16.3)
2005	(252.9)	(224.8)	(120.6)	(23.7)	(17.6)	(12.6)	(50.3)	(28.0)	(11.7)	(16.3)
2006	(249.0)	(219.6)	(119.1)	(23.6)	(19.2)	(13.4)	(44.4)	(29.4)	(12.1)	(17.3)
2007	(244.8)	(217.0)	(118.2)	(23.5)	(19.9)	(14.0)	(41.4)	(27.8)	(10.4)	(17.4)
2008	(237.6)	(216.9)	(118.6)	(23.6)	(20.0)	(14.0)	(40.7)	(20.7)	(3.6)	(17.0)
2009	(231.6)	(216.9)	(118.6)	(23.6)	(20.0)	(14.0)	(40.7)	(14.8)	1.8	(16.6)
2010	(233.4)	(217.2)	(118.6)	(23.6)	(20.3)	(14.0)	(40.7)	(16.2)	0.3	(16.5)
2011	(236.5)	(218.2)	(118.6)	(23.6)	(21.3)	(14.0)	(40.7)	(18.3)	(1.6)	(16.7)
2012	(236.3)	(218.2)	(118.6)	(23.6)	(21.3)	(14.0)	(40.7)	(18.1)	(1.3)	(16.8)

Table A-247: Estimated Carbon Stocks (Tg C) in Forest and Harvested Wood Pools, 1990–2013

		Forest						Harvested Wood			
Year	Total Carbon Stock	Total	Live, aboveground	Live, belowground	Dead Wood	Litter	Soil Organic Carbon	Total	Products in Use	SWDS	Forest Area (1000 ha)
1990	40,826	38,967	12,318	2,437	2,147	4,897	17,168	1,859	1,231	628	275,399
1991	41,018	39,123	12,415	2,456	2,161	4,903	17,188	1,895	1,249	646	276,027
1992	41,208	39,279	12,511	2,475	2,175	4,910	17,208	1,929	1,264	665	276,663
1993	41,396	39,434	12,609	2,494	2,189	4,916	17,225	1,963	1,280	683	277,275
1994	41,585	39,590	12,712	2,515	2,204	4,922	17,237	1,996	1,295	701	277,845
1995	41,781	39,752	12,819	2,535	2,219	4,927	17,252	2,029	1,311	718	278,409
1996	41,978	39,917	12,928	2,557	2,233	4,931	17,268	2,061	1,326	735	278,962
1997	42,171	40,079	13,038	2,579	2,253	4,933	17,277	2,092	1,340	752	279,401
1998	42,356	40,232	13,148	2,600	2,272	4,935	17,277	2,124	1,355	769	279,769
1999	42,525	40,370	13,253	2,621	2,290	4,934	17,272	2,155	1,368	787	280,134
2000	42,678	40,490	13,354	2,641	2,308	4,929	17,258	2,188	1,382	805	280,400
2001	42,825	40,606	13,454	2,661	2,327	4,922	17,243	2,218	1,395	823	280,613
2002	43,000	40,756	13,564	2,682	2,346	4,920	17,244	2,244	1,404	840	280,895
2003	43,211	40,940	13,676	2,704	2,366	4,925	17,268	2,271	1,414	857	281,323
2004	43,451	41,155	13,794	2,728	2,385	4,935	17,313	2,296	1,423	873	281,929
2005	43,701	41,377	13,915	2,751	2,404	4,946	17,361	2,325	1,435	890	282,583
2006	43,954	41,602	14,035	2,775	2,422	4,958	17,411	2,353	1,447	906	283,263
2007	44,203	41,821	14,154	2,799	2,441	4,972	17,456	2,382	1,459	923	283,829
2008	44,448	42,038	14,272	2,822	2,461	4,986	17,497	2,410	1,469	940	284,345
2009	44,686	42,255	14,391	2,846	2,481	5,000	17,538	2,430	1,473	958	284,858
2010	44,917	42,472	14,510	2,869	2,501	5,014	17,578	2,445	1,471	974	285,371
2011	45,151	42,689	14,628	2,893	2,521	5,028	17,619	2,461	1,471	991	285,884
2012	45,387	42,907	14,747	2,916	2,542	5,042	17,660	2,480	1,472	1,007	286,397
2013	45,623	43,126	14,866	2,940	2,564	5,056	17,700	2,498	1,474	1,024	286,910

Table A-248: State-Level Forest Area, Carbon Stock, and Net Annual Stock Change. Estimates are Forest Ecosystem carbon and Do Not Include Harvested Wood

State	Mean year of field data collection	Forest area (1000 ha)	Nonsoil C stock (Tg C)	Mean net annual nonsoil stock change 2003–2012 (Tg C/yr)
Alabama	2009	9,268	684	(7.0)
Alaska	2007	6,161	993	(5.0)
Arizona	2007	7,545	397	0.9
Arkansas	2010	7,666	584	(4.1)
California	2007	13,200	1,798	(6.5)
Colorado	2007	9,242	746	(1.1)
Connecticut	2010	693	83	(0.8)
Delaware	2010	137	16	(0.1)
Florida	2009	7,066	449	(4.3)
Georgia	2010	10,017	737	(6.2)
Idaho	2008	8,680	932	(0.2)
Illinois	2010	1,977	167	(3.2)
Indiana	2010	1,965	185	(2.5)
Iowa	2010	1,208	89	(1.6)
Kansas	2010	1,013	62	(1.4)
Kentucky	2010	5,047	444	(4.3)
Louisiana	2008	5,954	427	(2.7)
Maine	2010	7,138	621	(3.0)
Maryland	2010	996	118	(1.0)
Massachusetts	2010	1,224	146	(1.3)
Michigan	2010	8,214	698	(9.8)
Minnesota	2010	7,055	446	(4.8)
Mississippi	2009	7,886	574	(8.6)
Missouri	2010	6,266	464	(5.9)
Montana	2008	10,349	986	(7.3)
Nebraska	2009	638	38	(1.1)
Nevada	2005	4,520	193	(1.2)
New Hampshire	2011	1,956	219	(1.4)
New Jersey	2010	795	77	(0.7)
New Mexico	2011	10,052	499	(0.0)
New York	2010	7,675	850	(7.6)
North Carolina	2009	7,536	672	(7.4)
North Dakota	2010	305	16	(0.1)
Ohio	2010	3,273	329	(4.1)
Oklahoma	2010	5,118	237	(1.4)
Oregon	2007	12,061	1,781	(5.8)
Pennsylvania	2010	6,791	742	(7.0)
Rhode Island	2010	145	16	(0.3)
South Carolina	2010	5,285	423	(5.8)
South Dakota	2011	770	42	(0.7)
Tennessee	2010	5,642	572	(4.4)
Texas	2008	25,234	894	(0.9)
Utah	2007	7,339	423	(4.1)
Vermont	2010	1,858	221	(1.5)
Virginia	2010	6,437	616	(5.0)
Washington	2007	9,079	1,598	(8.5)
West Virginia	2010	4,919	547	(7.3)
Wisconsin	2010	6,909	508	(6.0)
Wyoming	2001	4,633	413	(1.1)

Table A-249 shows average C density values for forest ecosystem C pools according to region and forest types based on forest lands in this Inventory. These values were calculated by applying plot-level C estimation procedures as described below to the most recent inventory per state as available 11 July 2013 (USDA Forest Service 2013b). Carbon density values reflect the most recent survey for each state as available in the FIADB, not potential maximum C storage. Carbon densities are affected by the distribution of stand sizes within a forest type, which can range from regenerating to mature stands. A large proportion of young stands in a particular forest type are likely to reduce the regional average for C density.

Table A-249: Average Carbon Density (Mg C/ha) by Carbon Pool and Forest Area (1000 ha) According to Region and Forest Type, Based on the Most Recent Inventory Survey Available for Each State from FIA, Corresponding to an Average Year of 2009

Region (States) Forest Types	Above-ground Biomass	Below-ground Biomass	Dead Wood	Litter	Soil Organic Carbon	Forest Area
		Carbon Density (Mg C/ha)				(1,000 ha)
Northeast						
(CT,DE,MA,MD,ME,NH,NJ,NY,OH,PA,RI,VT,WV)						
White/Red/Jack Pine	79.0	16.3	6.9	13.8	78.1	1,661
Spruce/Fir	39.6	8.3	7.5	30.8	98.0	3,077
Oak/Pine	70.9	14.0	5.6	27.9	66.9	1,209
Oak/Hickory	78.1	14.8	6.3	8.2	53.1	13,027
Elm/Ash/Cottonwood	55.5	10.5	5.4	7.1	111.7	1,479
Maple/Beech/Birch	71.1	13.6	6.8	27.3	69.6	13,763
Aspen/Birch	42.4	8.3	5.9	8.7	87.4	1,551
Minor Types and Nonstocked	45.8	9.0	5.8	11.2	73.9	1,833
All	68.3	13.1	6.5	18.1	69.1	37,601
Northern Lake States						
(MI,MN,WI)						
White/Red/Jack Pine	46.3	9.6	5.6	12.4	120.8	1,915
Spruce/Fir	29.4	6.2	5.6	33.3	261.8	3,197
Oak/Hickory	54.4	10.3	7.0	8.1	97.1	4,002
Elm/Ash/Cottonwood	42.4	8.1	5.5	7.6	179.9	2,287
Maple/Beech/Birch	59.0	11.3	6.7	27.7	134.3	4,495
Aspen/Birch	31.8	6.1	6.1	8.3	146.1	5,096
Minor Types and Nonstocked	29.3	5.8	6.3	18.0	120.0	1,186
All	43.2	8.4	6.2	16.6	151.4	22,178
Northern Prairie States						
(IA,IL,IN,KS,MO,ND,NE,SD)						
Ponderosa Pine	32.1	6.7	4.5	14.4	48.5	550
Oak/Pine	40.0	7.7	4.4	26.1	40.7	572
Oak/Hickory	53.2	10.0	6.0	7.9	49.6	9,545
Elm/Ash/Cottonwood	56.4	10.5	6.4	6.9	83.1	2,041
Minor Types and Nonstocked	31.2	6.1	5.2	17.8	60.3	1,434
All	50.1	9.5	5.8	9.8	55.1	14,142
South Central						
(AL,AR,KY,LA,MS,OK,TN,TX)						
Loblolly/Shortleaf Pine	48.7	10.0	7.4	9.6	41.9	13,816
Pinyon/Juniper	12.1	2.3	4.0	12.2	37.7	4,030
Oak/Pine	44.8	8.8	6.6	9.3	41.7	5,121
Oak/Hickory	48.1	9.0	7.4	6.4	38.6	25,087
Oak/Gum/Cypress	63.7	12.1	7.5	6.5	52.8	5,278
Elm/Ash/Cottonwood	38.6	7.2	6.1	5.9	49.9	4,047
Woodland Hardwoods	9.6	1.5	1.9	5.0	65.0	9,454
Minor Types and Nonstocked	27.9	5.4	6.6	6.8	54.3	4,983
All	40.1	7.7	6.3	7.4	45.7	71,815
Southeast						
(FL,GA,NC,SC,VA)						
Longleaf/Slash Pine	41.0	8.5	4.9	10.0	110.0	4,174
Loblolly/Shortleaf Pine	53.1	11.0	4.3	9.8	72.9	9,309
Oak/Pine	51.2	10.0	4.0	9.4	61.4	4,066
Oak/Hickory	65.2	12.3	5.3	6.5	45.3	11,817
Oak/Gum/Cypress	64.2	12.5	5.3	6.5	158.0	4,622

Elm/Ash/Cottonwood	49.1	9.3	3.9	5.6	95.7	867
Minor Types and Nonstocked	31.4	6.0	7.0	5.7	110.9	1,485
All	55.9	10.9	4.9	8.0	79.8	36,341
Coastal Alaska						
(approximately 12 percent of forest land in Alaska)						
Spruce/Fir	14.7	2.9	7.8	33.5	62.1	395
Fir/Spruce/Mountain Hemlock	64.4	13.5	17.2	43.0	62.1	2,275
Hemlock/Sitka Spruce	116.5	24.5	27.4	50.4	116.3	2,808
Aspen/Birch	28.7	5.4	8.3	10.6	42.5	294
Minor Types and Nonstocked	29.8	5.8	7.3	22.9	74.6	389
All	81.1	17.0	20.2	42.9	86.7	6,161
Pacific Northwest, Westside						
(Western OR and WA)						
Douglas-fir	140.0	29.3	31.4	32.2	94.8	5,954
Fir/Spruce/Mountain Hemlock	130.3	27.5	35.7	38.5	62.1	1,210
Hemlock/Sitka Spruce	169.2	35.6	41.5	37.8	116.3	1,545
Alder/Maple	78.9	15.4	16.0	7.7	115.2	1,180
Minor Types and Nonstocked	56.0	11.0	17.5	12.9	86.0	1,234
All	127.2	26.5	30.1	28.9	95.4	11,124
Pacific Northwest, Eastside						
(Eastern OR and WA)						
Douglas-fir	62.9	13.1	18.3	36.3	94.8	2,020
Ponderosa Pine	41.1	8.5	9.7	22.5	50.7	2,809
Fir/Spruce/Mountain Hemlock	74.1	15.6	27.1	37.9	62.1	1,797
Lodgepole Pine	35.7	7.5	13.0	21.1	52.0	1,019
Western Larch	72.4	15.1	20.8	36.1	45.1	211
Other Western Softwoods	12.0	2.2	3.5	36.3	78.8	1,143
Minor Types and Nonstocked	27.3	5.3	17.0	24.4	80.7	1,016
All	46.8	9.7	15.2	30.0	67.9	10,017
Pacific Southwest						
(CA)						
Pinyon/Juniper	13.7	2.5	2.4	21.1	26.3	739
Douglas-fir	144.6	30.0	23.8	35.5	40.1	455
Ponderosa Pine	53.5	11.1	9.6	22.4	41.3	912
Fir/Spruce/Mountain Hemlock	111.3	23.5	29.6	38.4	51.9	817
Redwood	243.2	50.8	35.9	60.4	53.8	287
Other Western Softwoods	23.0	4.4	5.5	37.8	49.8	822
California Mixed Conifer	105.8	22.1	21.3	37.9	49.8	3,157
Western Oak	49.3	9.3	5.3	30.0	27.6	3,827
Tanoak/Laurel	126.0	24.7	12.4	28.3	27.6	805
Minor Types and Nonstocked	48.5	9.7	15.5	26.0	37.0	1,378
All	75.4	15.3	13.6	32.2	38.7	13,200
Rocky Mountain, North						
(ID,MT)						
Douglas-fir	11.2	2.2	1.8	21.1	41.7	638
Ponderosa Pine	50.9	10.7	13.1	37.0	38.8	5,473
Fir/Spruce/Mountain Hemlock	32.2	6.6	8.0	22.9	34.3	1,733
Lodgepole Pine	55.5	11.7	21.8	37.4	44.1	4,708
Western Larch	44.8	9.5	16.4	22.9	37.2	2,715
Other Western Softwoods	27.7	5.7	13.1	38.8	31.4	648
Aspen/Birch	22.2	4.1	14.7	26.8	56.6	504
Minor Types and Nonstocked	33.2	6.7	21.0	25.2	41.7	2,609
All	44.1	9.2	16.0	31.4	40.2	19,029
Rocky Mountain, South						
(AZ,CO,NM,NV,UT,WY)						
Pinyon/Juniper	15.1	3.0	1.8	21.1	19.7	20,800
Douglas-fir	49.7	10.5	12.8	38.3	30.9	1,694
Ponderosa Pine	37.0	7.7	7.5	23.8	24.1	3,264
Fir/Spruce/Mountain Hemlock	55.9	11.8	19.9	38.9	31.5	4,210
Lodgepole Pine	46.8	9.9	18.7	23.9	27.0	1,974
Aspen/Birch	39.9	7.6	10.6	28.5	58.8	2,569

Woodland Hardwoods	13.9	2.5	4.9	28.0	25.9	5,728
Minor Types and Nonstocked	13.1	2.4	9.6	22.8	25.5	3,092
All	24.7	5.0	6.7	25.3	25.5	43,330
United States (forest land included in Inventory)	**50.7**	**10.0**	**8.7**	**17.6**	**61.7**	**284,938**

Note: The forest area values in this table do not equal the forest area values reported in Table A-247, because the forest area values in this table are estimated using the most recent dataset per state, with an average year of 2009. The time series of forest area values reported in Table A-247, in contrast, is constructed following the CCT methods used to construct the C stock series. The forest area values reported in Table A-247 and Table A-249 would only be identical if all states were measured simultaneously or they all had identical rates of change.

The Inventory is derived primarily from the FIADB 5.1.6 data (USDA Forest Service 2013b), but it also draws on older FIA survey data where necessary. The Resources Planning Act Assessment (RPA) database, which includes periodic summaries of state inventories, is one example. Information about the RPA data is available on the Internet (USDA Forest Service 2013a), and compilations of analytical estimates based on these databases are found in Waddell et al. (1989) and Smith et al. (2001). Some differences between the RPA database and the FIADB are that the FIADB includes individual-tree data and includes additional land use categories such as “other wooded lands”.

Having only plot-level information (such as volume per hectare) limits the conversion to biomass. This does not constitute a substantial difference for the overall state-wide estimates, but it does affect plot-level precision (Smith et al. 2004). In the past, FIA made their data available in tree-level Eastwide (Hansen et al. 1992) or Westwide (Woudenberg and Farrenkopf 1995) formats, which included inventories for Eastern and Western states, respectively. The current Inventory estimates rely, in part, on older tree-level data that are not available on the current FIADB site. The Integrated Database (IDB) is a compilation of periodic forest inventory data from the 1990s for California, Oregon, and Washington (Waddell and Hiserote 2005). These data were identified by Heath et al. (2011) as the most appropriate non-FIADB sources for these three states.

A historical focus of the FIA program was to provide information on timber resources of the United States. For this reason, prior to 1998, some forest land, which were less productive or reserved (i.e., land where harvesting was prohibited by law), were less intensively surveyed. This generally meant that on these less productive lands, forest type and area were identified but data were not collected on individual tree measurements. The practical effect that this evolution in inventories has had on estimating forest C stocks from 1990 through the present is that some older surveys of lands do not have the individual-tree data or even stand-level characteristics such as stand age. Any data gaps identified in the surveys taken before 1998 were filled by assigning average C densities calculated from the more complete, later inventories from the respective states. The overall effect of this necessary approach to generate estimates for C stock is that no net change in C density occurs on those lands with gaps in past surveys (for further discussion see Domke et al. In Review). This approach to filling gaps in older data also extends to timberlands where individual-tree data was not available (e.g., standing dead trees).

Estimating C stocks from forest inventory data

For each inventory summary in each state, data are converted to C units or augmented by other ecological data. Most of the conversion factors and models used for inventory-based forest C estimates (Smith et al. 2010, Heath et al. 2011) were initially developed as an offshoot of the forest C simulation model FORCARB (Heath et al. 2010) and are incorporated into a number of applications (Birdsey and Heath 1995, Birdsey and Heath 2001, Heath et al. 2003, Smith et al. 2004, Hoover and Rebain 2008). The conversion factors and model coefficients are usually categorized by region and forest type. Classifications for both of these categories are subject to change depending on the particular coefficient set. Thus, region and type are specifically defined for each set of estimates. Factors are applied to the survey data at the scale of FIA inventory plots. The results are estimates of C density (Mg per hectare) for the various forest pools. Carbon density for live trees, standing dead trees, understory vegetation, downed dead wood, litter, and soil organic matter are estimated. All non-soil pools except litter can be separated into aboveground and belowground components. The live tree and understory C pools are pooled as biomass in this inventory. Similarly, standing dead trees and downed dead wood are pooled as dead wood in this inventory. C stocks and fluxes for *Forest Land Remaining Forest Land* are reported in pools following IPCC (2003).

Live tree C pools

Live tree C pools include aboveground and belowground (coarse root) biomass of live trees with diameter at diameter breast height (d.b.h.) of at least 2.54 cm at 1.37 m above the forest floor. Separate estimates are made for above-and below-ground biomass components. If inventory plots include data on individual trees, tree C is based on Woodall et al. (2011), which is also known as the component ratio method (CRM), and is a function of volume, species, diameter, and, in some regions, tree height and site quality. The estimated sound volume provided in the tree table of the FIADB is the principal input to the CRM biomass calculation for each tree. The estimated volumes of wood and bark are converted to biomass based on the density of each. Additional components of the trees such as tops, branches, and coarse roots, are estimated according to adjusted component estimates from Jenkins et al. (2003). Live trees with d.b.h of less than 12.7 cm do not have estimates of sound volume in the FIADB, and CRM biomass estimates follow a separate process (see Woodall et al. 2011 for details). An additional component of foliage, which was not explicitly included in Woodall et al. (2011), was added to each tree following the same CRM method. Carbon is estimated by multiplying the estimated oven-dry biomass by a C constant of 0.5 because biomass is 50 percent of dry weight (IPCC/UNEP/OECD/IEA 1997). Further discussion and example calculations are provided in Woodall et al. 2011 and Domke et al. 2012.

Some of the older forest inventory data in use for these estimates do not provide measurements of individual trees. Examples of these data include plots with incomplete or missing tree data (e.g., some of the non-timberland plots in older surveys) or the RPA plot-level summaries. The C estimates for these plots are based on average densities (metric tons C per hectare) obtained from plots of more recent surveys with similar stand characteristics and location. This applies to less than 5 percent of the forest land inventory-plot-to-C conversions within the 193 state-level surveys utilized here.

Understory vegetation

Understory vegetation is a minor component of total forest ecosystem biomass. Understory vegetation is defined as all biomass of undergrowth plants in a forest, including woody shrubs and trees less than one-inch d.b.h. In this inventory, it is assumed that 10 percent of understory C mass is belowground. This general root-to-shoot ratio (0.11) is near the lower range of temperate forest values provided in IPCC (2006) and was selected based on two general assumptions: ratios are likely to be lower for light-limited understory vegetation as compared with larger trees, and a greater proportion of all root mass will be less than 2 mm diameter.

Estimates of C density are based on information in Birdsey (1996), which was applied to FIA permanent plots. These were fit to the model:

$$\text{Ratio} = e^{(A - B \times \ln(\text{live tree C density}))}$$

In this model, the ratio is the ratio of understory C density (Mg C/ha) to live tree C density (above- and below-ground) according to Jenkins et al. (2003) and expressed in Mg C/ha. An additional coefficient is provided as a maximum ratio; that is, any estimate predicted from the model that is greater than the maximum ratio is set equal to the maximum ratio. A full set of coefficients are in Table A-250. Regions and forest types are the same classifications described in Smith et al. (2003). As an example, the basic calculation for understory C in aspen-birch forests in the Northeast is:

$$\text{Understory (Mg C/ha)} = (\text{live tree C density}) \times e^{(0.855 - 1.03 \times \ln(\text{tree C density}))}$$

This calculation is followed by three possible modifications. First, the maximum value for the ratio is set to 2.02 (see value in column "maximum ratio"); this also applies to stands with zero tree C, which is undefined in the above model. Second, the minimum ratio is set to 0.005 (Birdsey 1996). Third, nonstocked and pinyon/juniper stands are set to coefficient A, which is a C density (Mg C/ha) for these types only.

Table A-250: Coefficients for Estimating the Ratio of Carbon Density of Understory Vegetation (above- and belowground, MgC/ha)[a] by Region and Forest Type. The Ratio is Multiplied by Tree Carbon Density on Each Plot to Produce Understory Vegetation

Region[b]	Forest Type[b]	A	B	Maximum ratio[c]
NE	Aspen-Birch	0.855	1.032	2.023
	MBB/Other Hardwood	0.892	1.079	2.076
	Oak-Hickory	0.842	1.053	2.057
	Oak-Pine	1.960	1.235	4.203
	Other Pine	2.149	1.268	4.191
	Spruce-Fir	0.825	1.121	2.140
	White-Red-Jack Pine	1.000	1.116	2.098
	Nonstocked	2.020	2.020	2.060
NLS	Aspen-Birch	0.777	1.018	2.023
	Lowland Hardwood	0.650	0.997	2.037

	Maple-Beech-Birch	0.863	1.120	2.129
	Oak-Hickory	0.965	1.091	2.072
	Pine	0.740	1.014	2.046
	Spruce-Fir	1.656	1.318	2.136
	Nonstocked	1.928	1.928	2.117
NPS	Conifer	1.189	1.190	2.114
	Lowland Hardwood	1.370	1.177	2.055
	Maple-Beech-Birch	1.126	1.201	2.130
	Oak-Hickory	1.139	1.138	2.072
	Oak-Pine	2.014	1.215	4.185
	Nonstocked	2.052	2.052	2.072
PSW	Douglas-fir	2.084	1.201	4.626
	Fir-Spruce	1.983	1.268	4.806
	Hardwoods	1.571	1.038	4.745
	Other Conifer	4.032	1.785	4.768
	Pinyon-Juniper	4.430	4.430	4.820
	Redwood	2.513	1.312	4.698
	Nonstocked	4.431	4.431	4.626
PWE	Douglas-fir	1.544	1.064	4.626
	Fir-Spruce	1.583	1.156	4.806
	Hardwoods	1.900	1.133	4.745
	Lodgepole Pine	1.790	1.257	4.823
	Pinyon-Juniper	2.708	2.708	4.820
	Ponderosa Pine	1.768	1.213	4.768
	Nonstocked	4.315	4.315	4.626
PWW	Douglas-fir	1.727	1.108	4.609
	Fir-Spruce	1.770	1.164	4.807
	Other Conifer	2.874	1.534	4.768
	Other Hardwoods	2.157	1.220	4.745
	Red Alder	2.094	1.230	4.745
	Western Hemlock	2.081	1.218	4.693
	Nonstocked	4.401	4.401	4.589
RMN	Douglas-fir	2.342	1.360	4.731
	Fir-Spruce	2.129	1.315	4.749
	Hardwoods	1.860	1.110	4.745
	Lodgepole Pine	2.571	1.500	4.773
	Other Conifer	2.614	1.518	4.821
	Pinyon-Juniper	2.708	2.708	4.820
	Ponderosa Pine	2.099	1.344	4.776
	Nonstocked	4.430	4.430	4.773
RMS	Douglas-fir	5.145	2.232	4.829
	Fir-Spruce	2.861	1.568	4.822
	Hardwoods	1.858	1.110	4.745
	Lodgepole Pine	3.305	1.737	4.797
	Other Conifer	2.134	1.382	4.821
	Pinyon-Juniper	2.757	2.757	4.820
	Ponderosa Pine	3.214	1.732	4.820
	Nonstocked	4.243	4.243	4.797
SC	Bottomland Hardwood	0.917	1.109	1.842
	Misc. Conifer	1.601	1.129	4.191
	Natural Pine	2.166	1.260	4.161
	Oak-Pine	1.903	1.190	4.173
	Planted Pine	1.489	1.037	4.124
	Upland Hardwood	2.089	1.235	4.170
	Nonstocked	4.044	4.044	4.170
SE	Bottomland Hardwood	0.834	1.089	1.842
	Misc. Conifer	1.601	1.129	4.191
	Natural Pine	1.752	1.155	4.178
	Oak-Pine	1.642	1.117	4.195
	Planted Pine	1.470	1.036	4.141
	Upland Hardwood	1.903	1.191	4.182
	Nonstocked	4.033	4.033	4.182

[a] Prediction of ratio of understory C to live tree C is based on the model: Ratio=exp(A − B × ln(tree_carbon_tph)), where "ratio" is the ratio of understory C density to live tree (above-and below- ground) C density, and "tree_carbon_density" is live tree (above-and below- ground) C density in Mg C/ha.
[b] Regions and types as defined in Smith et al. (2003).
[c] Maximum ratio: any estimate predicted from the model that is greater than the maximum ratio is set equal to the maximum ratio.

Dead Wood

The standing dead tree estimates are primarily based on plot-level measurements (Domke et al. 2011, Woodall et al. 2011). This C pool includes aboveground and belowground (coarse root) mass and includes trees of at least 12.7 cm d.b.h. Calculations follow the basic CRM method applied to live trees (Woodall et al. 2011) with additional modifications to account for decay and structural loss. In addition to the lack of foliage, two characteristics of standing dead trees that can significantly affect C mass are decay, which affects density and thus specific C content (Domke et al. 2011, Harmon et al. 2011), and structural loss such as branches and bark (Domke et al. 2011). Dry weight to C mass conversion is by multiplying by 0.5.

Some of the older forest inventory data in use for these estimates do not provide measurements of individual standing dead trees. In addition to the RPA data, which are plot-level summaries, some of the older surveys that otherwise include individual-tree data may not completely sample dead trees on non-timberlands and in some cases timberlands. The C estimates for these plots are based on average densities (metric tons C per hectare) obtained from plots of more recent surveys with similar stand characteristics and location. This applies to 23 percent of the forest land inventory-plot-to-C conversions within the 193 state-level surveys utilized here.

Downed dead wood, inclusive of logging residue, are sampled on a subset of FIA plots. Despite a reduced sample intensity, a single down woody material population estimate (Woodall et al. 2010, Domke et al. 2013, Woodall et al. 2013) per state is now incorporated into these empirical downed dead wood estimates. Downed dead wood is defined as pieces of dead wood greater than 7.5 cm diameter, at transect intersection, that are not attached to live or standing dead trees. It also includes stumps and roots of harvested trees. Ratio estimates of downed dead wood to live tree biomass were developed using FORCARB2 simulations and applied at the plot level (Smith et al. 2004). Estimates for downed dead wood correspond to the region and forest type classifications described in Smith et al. (2003). A full set of ratios is provided in Table A-251. An additional component of downed dead wood is a regional average estimate of logging residue based on Smith et al. (2006) applied at the plot level. These are based on a regional average C density at age zero and first order decay; initial densities and decay coefficients are provided in Table A-252. These amounts are added to explicitly account for downed dead wood following harvest. The sum of these two components are then adjusted by the ratio of population totals; that is, the ratio of plot-based to modeled estimates (Domke et al. 2013). An example of this 3-part calculation for downed dead wood in a 25-year-old naturally regenerated loblolly pine forest with 82.99 Mg C/ha in live trees (Jenkins et al. 2003) in Louisiana is as follows:

First, an initial estimate from live tree C density and Table A-251 (SC, Natural Pine)

C density = 82.99 × 0.068 = 5.67 (Mg C/ha)

Second, an average logging residue from age and Table A-252 (SC, softwood) C density = $5.5 \times e^{(-25/17.9)} = 1.37$ (Mg C/ha)

Third, adjust the sum by the downed dead wood ratio plot-to-model for Louisiana, which was 27.6/31.1 = 0.886

C density = (5.67 + 1.37) × 0.886 = 6.24 (Mg C/ha)

Table A-251: Ratio for Estimating Down Dead Wood by Region and Forest Type. The Ratio is Multiplied by the Live Tree Carbon Density on a Plot to Produce Down Dead Wood Carbon Density (Mg C/ha)

Region[a]	Forest type[a]	Ratio	Region (cont'd)	Forest type (cont'd)	Ratio (cont'd)
NE	Aspen-Birch	0.078	PWW	Douglas-fir	0.100
	MBB/Other Hardwood	0.071		Fir-Spruce	0.090
	Oak-Hickory	0.068		Other Conifer	0.073
	Oak-Pine	0.061		Other Hardwoods	0.062
	Other Pine	0.065		Red Alder	0.095
	Spruce-Fir	0.092		Western Hemlock	0.099
	White-Red-Jack Pine	0.055		Nonstocked	0.020
	Nonstocked	0.019	RMN	Douglas-fir	0.062

NLS	Aspen-Birch	0.081
	Lowland Hardwood	0.061
	Maple-Beech-Birch	0.076
	Oak-Hickory	0.077
	Pine	0.072
	Spruce-Fir	0.087
	Nonstocked	0.027
NPS	Conifer	0.073
	Lowland Hardwood	0.069
	Maple-Beech-Birch	0.063
	Oak-Hickory	0.068
	Oak-Pine	0.069
	Nonstocked	0.026
PSW	Douglas-fir	0.091
	Fir-Spruce	0.109
	Hardwoods	0.042
	Other Conifer	0.100
	Pinyon-Juniper	0.031
	Redwood	0.108
	Nonstocked	0.022
PWE	Douglas-fir	0.103
	Fir-Spruce	0.106
	Hardwoods	0.027
	Lodgepole Pine	0.093
	Pinyon-Juniper	0.032
	Ponderosa Pine	0.103
	Nonstocked	0.024
	Fir-Spruce	0.100
	Hardwoods	0.112
	Lodgepole Pine	0.058
	Other Conifer	0.060
	Pinyon-Juniper	0.030
	Ponderosa Pine	0.087
	Nonstocked	0.018
RMS	Douglas-fir	0.077
	Fir-Spruce	0.079
	Hardwoods	0.064
	Lodgepole Pine	0.098
	Other Conifer	0.060
	Pinyon-Juniper	0.030
	Ponderosa Pine	0.082
	Nonstocked	0.020
SC	Bottomland Hardwood	0.063
	Misc. Conifer	0.068
	Natural Pine	0.068
	Oak-Pine	0.072
	Planted Pine	0.077
	Upland Hardwood	0.067
	Nonstocked	0.013
SE	Bottomland Hardwood	0.064
	Misc. Conifer	0.081
	Natural Pine	0.081
	Oak-Pine	0.063
	Planted Pine	0.075
	Upland Hardwood	0.059
	Nonstocked	0.012

[a] Regions and types as defined in Smith et al. (2003).

Table A-252: Coefficients for Estimating Logging Residue Component of Down Dead Wood

Region[a]	Forest Type Group[b] (softwood/hardwood)	Initial Carbon Density (Mg/ha)	Decay Coefficient
Alaska	hardwood	6.9	12.1
Alaska	softwood	8.6	32.3
NE	hardwood	13.9	12.1
NE	softwood	12.1	17.9
NLS	hardwood	9.1	12.1
NLS	softwood	7.2	17.9
NPS	hardwood	9.6	12.1
NPS	softwood	6.4	17.9
PSW	hardwood	9.8	12.1
PSW	softwood	17.5	32.3
PWE	hardwood	3.3	12.1
PWE	softwood	9.5	32.3
PWW	hardwood	18.1	12.1
PWW	softwood	23.6	32.3
RMN	hardwood	7.2	43.5
RMN	softwood	9.0	18.1
RMS	hardwood	5.1	43.5
RMS	softwood	3.7	18.1
SC	hardwood	4.2	8.9
SC	softwood	5.5	17.9
SE	hardwood	6.4	8.9
SE	softwood	7.3	17.9

[a] Regions are defined in Smith et al. (2003) with the addition of coastal Alaska.
[b] Forest types are according to majority hardwood or softwood species.

Litter carbon

Carbon of the litter layer is currently sampled on a subset of the FIA plots. However, these data are not yet available electronically for general application to all inventories in Table A-245. Litter C is the pool of organic C (including material known as duff, humus, and fine woody debris) above the mineral soil and includes woody fragments with diameters of up to 7.5 cm. Estimates therefore continue to be based on models of Smith and Heath (2002) and applied at the plot level. The models describe processes for decay or loss of forest floor following harvest and the net accumulation of new forest floor material following stand growth. For example, total forest floor C at a given number of years after a clearcut harvest for aspen-birch forests in the North is:

$$\text{Total forest floor C (Mg C/ha)} = (18.4 \times \text{years})/(53.7 + \text{years}) + 10.2 \times e^{(-\text{years} \div 9.2)}$$

See Table 4 of Smith and Heath (2002) for the complete set of coefficients. Note that these are direct estimates of C density; the 0.5 conversion does not apply to litter.

Soil organic carbon

Soil organic carbon (SOC) is currently sampled to a 20 cm depth on subsets of FIA plots, however, these data are not available for the entire United States. Thus, estimates of SOC are based on the national STATSGO spatial database (USDA 1991), and the general approach described by Amichev and Galbraith (2004). In their procedure, SOC was calculated for the conterminous United States using the STATSGO database, and data gaps were filled by representative values from similar soils. Links to region and forest type groups were developed with the assistance of the USDA Forest Service FIA Geospatial Service Center by overlaying FIA forest inventory plots on the soil C map.

Carbon in Harvested Wood Products

Estimates of the harvested wood product (HWP) contribution to forest C sinks and emissions (hereafter called “HWP Contribution”) are based on methods described in Skog (2008) using the WOODCARB II model. These methods are based on IPCC (2006) guidance for estimating HWP C. The 2006 IPCC Guidelines provide methods that allow Parties to report HWP Contribution using one of several different accounting approaches: production, stock change, and atmospheric flow, as well as a default method. The various approaches are described below. The approaches differ in how HWP Contribution is allocated based on production or consumption as well as what processes (atmospheric fluxes or stock changes) are emphasized.

- **Production approach**: Accounts for the net changes in C stocks in forests and in the wood products pool, but attributes both to the producing country.
- **Stock change approach**: Accounts for changes in the product pool within the boundaries of the consuming country.
- **Atmospheric flow approach**: Accounts for net emissions or removals of C to and from the atmosphere within national boundaries. Carbon removal due to forest growth is accounted for in the producing country while C emissions to the atmosphere from oxidation of wood products are accounted for in the consuming country.
- **Default approach**: Assumes no change in C stocks in HWP. IPCC (2006) requests that such an assumption be justified if this is how a Party is choosing to report.

The United States uses the production accounting approach (as in previous years) to report HWP Contribution (Table A-256). Though reported U.S. HWP estimates are based on the production approach, estimates resulting from use of the two alternative approaches—the stock change and atmospheric flow approaches—are also presented for comparison (see Table A-257). Annual estimates of change are calculated by tracking the additions to and removals from the pool of products held in end uses (i.e., products in use such as housing or publications) and the pool of products held in solid waste disposal sites (SWDS).

Estimates of five HWP variables that can be used to calculate HWP contribution for the stock change and atmospheric flow approaches for imports and exports are provided in Table A-256. The HWP variables estimated are:

(1A) annual change of C in wood and paper products in use in the United States,

(1B) annual change of C in wood and paper products in SWDS in the United States, (2A) annual change of C in wood and paper products in use in the United States and other countries where the wood came from trees harvested in the United States,

(2B) annual change of C in wood and paper products in SWDS in the United States and other countries where the wood came from trees harvested in the United States,

(3) Carbon in imports of wood, pulp, and paper to the United States,

(4) Carbon in exports of wood, pulp and paper from the United States, and

(5) Carbon in annual harvest of wood from forests in the United States.

Table A-253: Harvested Wood Products from Wood Harvested in United States—Annual Additions of Carbon to Stocks and Total Stocks Under the Production Approach (Parentheses Indicate Net C Sequestration (i.e., a Net Removal of C from the Atmosphere)

Year	Net carbon additions per year (Tg C per year)							Total Carbon stocks (Tg C)		
		Products in use			Products in SWDS					
	Total	Total	Solid wood products	Paper products	Total	Solid wood products	Paper products	Total	Products in use	Products in SWDS
1990	(35.9)	(17.7)	(14.4)	(3.3)	(18.3)	(9.9)	(8.3)	1,859	1,231	628
1991	(33.8)	(14.9)	(11.9)	(3.1)	(18.8)	(11.1)	(7.7)	1,895	1,249	646
1992	(33.8)	(16.3)	(12.6)	(3.7)	(17.4)	(9.5)	(7.9)	1,929	1,264	665
1993	(32.9)	(15.0)	(12.2)	(2.8)	(17.9)	(9.7)	(8.3)	1,963	1,280	683
1994	(33.4)	(15.9)	(12.1)	(3.8)	(17.5)	(9.8)	(7.7)	1,996	1,295	701
1995	(32.3)	(15.1)	(11.2)	(3.8)	(17.2)	(10.7)	(6.5)	2,029	1,311	718
1996	(30.6)	(14.1)	(11.5)	(2.6)	(16.5)	(10.6)	(6.0)	2,061	1,326	735
1997	(32.0)	(14.7)	(11.8)	(3.0)	(17.3)	(10.3)	(6.9)	2,092	1,340	752
1998	(31.1)	(13.4)	(11.4)	(2.0)	(17.7)	(10.2)	(7.5)	2,124	1,355	769
1999	(32.5)	(14.1)	(12.1)	(2.0)	(18.4)	(10.6)	(7.8)	2,155	1,368	787
2000	(30.8)	(12.8)	(11.9)	(1.0)	(18.0)	(10.7)	(7.3)	2,188	1,382	805
2001	(25.5)	(8.7)	(10.1)	1.4	(16.8)	(10.7)	(6.0)	2,218	1,395	823
2002	(26.8)	(9.6)	(10.7)	1.1	(17.2)	(11.1)	(6.1)	2,244	1,404	840
2003	(25.6)	(9.4)	(9.9)	0.5	(16.2)	(11.0)	(5.1)	2,271	1,414	857
2004	(28.3)	(12.0)	(11.3)	(0.8)	(16.3)	(11.3)	(5.0)	2,296	1,423	873
2005	(28.0)	(11.7)	(11.3)	(0.4)	(16.3)	(11.5)	(4.8)	2,325	1,435	890
2006	(29.4)	(12.1)	(10.5)	(1.7)	(17.3)	(11.6)	(5.7)	2,353	1,447	906
2007	(27.8)	(10.4)	(8.5)	(1.9)	(17.4)	(11.6)	(5.7)	2,382	1,459	923
2008	(20.7)	(3.6)	(2.9)	(0.8)	(17.0)	(11.4)	(5.7)	2,410	1,469	940
2009	(14.8)	1.8	0.5	1.3	(16.6)	(11.2)	(5.4)	2,430	1,473	958
2010	(16.2)	0.3	0.2	0.2	(16.5)	(11.3)	(5.2)	2,445	1,471	974
2011	(18.3)	(1.6)	(1.0)	(0.6)	(16.7)	(11.4)	(5.3)	2,461	1,471	991
2012	(18.1)	(1.3)	(1.4)	0.1	(16.8)	(11.4)	(5.4)	2,480	1,472	1,007
2013								2,498	1,474	1,024

Table A-254: Comparison of Net Annual Change in Harvested Wood Products Carbon Stocks Using Alternative Accounting Approaches

	HWP Contribution to LULUCF Emissions/ removals (Tg CO_2 Eq.)		
Inventory Year	Stock Change Approach	Atmospheric Flow Approach	Production Approach
1990	(129.6)	(138.4)	(131.8)
1991	(116.3)	(131.4)	(123.8)
1992	(120.0)	(131.6)	(123.8)
1993	(126.8)	(127.8)	(120.7)
1994	(130.0)	(129.9)	(122.5)

1995	(126.0)	(128.0)	(118.4)
1996	(122.3)	(122.5)	(112.2)
1997	(131.4)	(127.4)	(117.3)
1998	(137.2)	(122.8)	(114.2)
1999	(147.1)	(127.4)	(119.2)
2000	(141.2)	(120.4)	(113.0)
2001	(125.0)	(100.4)	(93.5)
2002	(130.7)	(103.3)	(98.2)
2003	(125.8)	(98.7)	(93.8)
2004	(143.2)	(108.5)	(103.8)
2005	(142.1)	(107.3)	(102.8)
2006	(138.1)	(113.9)	(107.8)
2007	(115.1)	(111.5)	(101.8)
2008	(73.1)	(88.4)	(75.8)
2009	(42.3)	(69.8)	(54.1)
2010	(50.5)	(79.4)	(59.3)
2011	(52.9)	(90.9)	(67.1)
2012	(57.7)	(90.8)	(66.5)

Note: Parentheses indicate net C sequestration (i.e., a net removal of C from the atmosphere).

Table A-255: Harvested Wood Products Sectoral Background Data for LULUCF—United States (production approach)

	1A	1B	2A	2B	3	4	5	6	7	8
Inventory year	Annual Change in stock of HWP in use from consumption	Annual Change in stock of HWP in SWDS from consumption	Annual Change in stock of HWP in use produced from domestic harvest	Annual Change in stock of HWP in SWDS produced from domestic harvest	Annual Imports of wood, and paper products plus wood fuel, pulp, recovered paper, roundwood/ chips	Annual Exports of wood, and paper products plus wood fuel, pulp, recovered paper, roundwood/ chips	Annual Domestic Harvest	Annual release of carbon to the atmosphere from HWP consumption (from fuelwood and products in use and products in SWDS)	Annual release of carbon to the atmosphere from HWP (including firewood) where wood came from domestic harvest (from products in use and products in SWDS)	HWP Contribution to AFOLU CO_2 emissions/ removals
	$\Delta C_{HWP\ IU\ DC}$	$\Delta C_{HWP\ SWDS\ DC}$	$\Delta C_{HWP\ IU\ DH}$	$\Delta C_{HWP\ SWDS\ DH}$	P_{IM}	P_{EX}	H	$\uparrow C_{HWP\ DC}$	$\uparrow C_{HWP\ DH}$	
									Gg C/yr	Gg CO_2/yr
1990	17,044	18,308	17,659	18,278	12,680	15,078	142,297	104,547	106,359	(131,772)
1991	13,129	18,602	14,940	18,812	11,552	15,667	144,435	108,588	110,682	(123,758)
1992	15,718	17,006	16,334	17,427	12,856	16,032	139,389	103,489	105,627	(123,791)
1993	16,957	17,627	14,971	17,949	14,512	14,788	134,554	99,694	101,633	(120,708)
1994	18,221	17,221	15,930	17,479	15,685	15,665	134,750	99,328	101,342	(122,498)
1995	17,307	17,051	15,065	17,229	16,712	17,266	137,027	102,115	104,733	(118,411)
1996	17,018	16,348	14,092	16,513	16,691	16,733	134,477	101,069	103,872	(112,219)
1997	18,756	17,090	14,740	17,263	17,983	16,877	135,439	100,699	103,436	(117,344)
1998	19,654	17,769	13,404	17,738	18,994	15,057	134,206	100,720	103,064	(114,188)
1999	21,444	18,662	14,146	18,359	20,599	15,245	134,193	99,440	101,689	(119,182)
2000	20,000	18,508	12,840	17,970	21,858	16,185	133,694	100,859	102,884	(112,969)

2001	16,491	17,610	8,713	16,781	22,051	15,336	127,896	100,510	102,402	(93,479)
2002	17,414	18,235	9,566	17,213	23,210	15,744	126,866	98,683	100,087	(98,188)
2003	16,986	17,326	9,415	16,171	23,707	16,303	126,477	99,569	100,891	(93,815)
2004	21,409	17,643	12,045	16,268	26,428	16,953	131,738	102,160	103,425	(103,814)
2005	20,992	17,765	11,746	16,290	26,793	17,313	132,482	103,205	104,446	(102,798)
2006	19,085	18,587	12,135	17,269	25,443	18,836	129,529	98,464	100,125	(107,815)
2007	13,085	18,308	10,405	17,364	21,648	20,656	123,640	93,239	95,871	(101,820)
2008	2,414	17,510	3,627	17,043	16,980	21,157	106,096	81,996	85,426	(75,789)
2009	(5,104)	16,641	(1,836)	16,600	13,114	20,616	96,032	76,994	81,269	(54,133)
2010	(2,564)	16,324	(334)	16,501	14,161	22,052	97,555	75,904	81,388	(59,279)
2011	(1,761)	16,184	1,595	16,700	13,922	24,302	100,848	76,045	82,553	(67,082)
2012	(363)	16,113	1,345	16,787	13,950	22,961	103,019	78,258	84,887	(66,485)

Note: $\uparrow C_{HWP\ DC} = H + P_{IM} - P_{EX} - \Delta C_{HWP\ IU\ DC} - \Delta C_{HWP\ SWDS\ DC}$ AND $\uparrow C_{HWP\ DH} = H - \Delta C_{HWP\ IU\ DH} - \Delta C_{HWP\ SWDS\ DH}$. Parentheses indicate net C sequestration (i.e., a net removal of C from the atmosphere).

Annual estimates of variables 1A, 1B, 2A and 2B were calculated by tracking the additions to and removals from the pool of products held in end uses (e.g., products in uses such as housing or publications) and the pool of products held in SWDS. In the case of variables 2A and 2B, the pools include products exported and held in other countries and the pools in the United States exclude products made from wood harvested in other countries. Solidwood products added to pools include lumber and panels. End-use categories for solidwood include single and multifamily housing, alteration and repair of housing, and other end uses. There is one product category and one end-use category for paper. Additions to and removals from pools are tracked beginning in 1900, with the exception that additions of softwood lumber to housing begins in 1800. Solidwood and paper product production and trade data are from USDA Forest Service and other sources (Hair and Ulrich 1963; Hair 1958; USDC Bureau of Census 1976; Ulrich, 1985, 1989; Steer 1948; AF&PA 2006a, 2006b; Howard 2003).

The rate of removals from products in use and the rate of decay of products in SWDS are specified by first order (exponential) decay curves with given half-lives (time at which half of amount placed in use will have been discarded from use). Half-lives for products in use, determined after calibration of the model to meet two criteria, are shown in Table A-256. The first criterion is that the WOODCARB II model estimate of C in houses standing in 2001 needed to match an independent estimate of C in housing based on U.S. Census and USDA Forest Service survey data. The second criterion is that the WOODCARB II model estimate of wood and paper being discarded to SWDS needed to match EPA estimates of discards over the period 1990 to 2000. This calibration strongly influences the estimate of variable 1A, and to a lesser extent variable 2A. The calibration also determines the amounts going to SWDS. In addition ,WOODCARB II landfill decay rates have been validated by making sure that estimates of methane emissions from landfills based on EPA data are reasonable in comparison to methane estimates based on WOODCARB II landfill decay rates.

Decay parameters for products in SWDS are shown in Table A-257. Estimates of 1B and 2B also reflect the change over time in the fraction of products discarded to SWDS (versus burning or recycling) and the fraction of SWDS that are sanitary landfills versus dumps.

Variables 2A and 2B are used to estimate HWP contribution under the production accounting approach. A key assumption for estimating these variables is that products exported from the United States and held in pools in other countries have the same half lives for products in use, the same percentage of discarded products going to SWDS, and the same decay rates in SWDS. Summaries of net fluxes and stocks for harvested wood in products and SWDS are in Table A-246 and Table A-247. The decline in net additions to HWP C stocks continued through 2009 from the recent high point in 2006. This is due to sharp declines in U.S. production of solidwood and paper products in 2009 primarily due to the decline in housing construction. The low level of gross additions to solidwood and paper products in use in 2009 was exceeded by discards from uses. The result is a net reduction in the amount of HWP C that is held in products in use during 2009. For 2009 additions to landfills still exceeded emissions from landfills and the net additions to landfills have remained relatively stable. Overall, there were net C additions to HWP in use and in landfills combined.

Table A-256: Half life of Solidwood and Paper Products in End uses

Parameter	Value	Units
Half life of wood in single family housing 1920 and before	78.0	Years
Half life of wood in single family housing 1920–1939	78.0	Years
Half life of wood in single family housing 1940–1959	80.0	Years
Half life of wood in single family housing 1960–1979	81.9	Years
Half life of wood in single family housing 1980 +	83.9	Years
Ratio of multifamily half live to single family half life	0.61	
Ratio of repair and alterations half life to single family half life	0.30	
Half life for other solidwood product in end uses	38.0	Years
Half life of paper in end uses	2.54	Years

Source: Skog, K.E. (2008) "Sequestration of C in harvested wood products for the United States." *Forest Products Journal* 58:56–72.

Table A-257: Parameters Determining Decay of Wood and Paper in SWDS

Parameter	Value	Units
Percentage of wood and paper in dumps that is subject to decay	100	Percent
Percentage of wood in landfills that is subject to decay	23	Percent
Percentage of paper in landfills that is subject to decay	56	Percent
Half life of wood in landfills / dumps (portion subject to decay)	29	Years
Half life of paper in landfills/ dumps (portion subject to decay)	14.5	Years

Source: Skog, K.E. (2008) "Sequestration of C in harvested wood products for the United States." *Forest Products Journal* 58:56–72

Uncertainty Analysis

The uncertainty analyses for total net flux of forest C (see uncertainty table in LULUCF chapter) are consistent with the IPCC-recommended Tier 2 methodology (IPCC 2006). Separate analyses are produced for forest ecosystem and HWP flux. The uncertainty estimates are from Monte Carlo simulations of the respective models and input data. Methods generally follow those described in Heath and Smith (2000), Smith and Heath (2000), and Skog et al. (2004). Uncertainties surrounding input data or model processes are quantified as probability distribution functions (PDFs), so that a series of sample values can be randomly selected from the distributions. Model simulations are repeated a large number of times to numerically simulate the effects of the random PDF selections on estimated total C flux. The separate results from the ecosystem and HWP simulations are pooled for total uncertainty (see uncertainty table in LULUCF chapter).

Uncertainty surrounding current net C flux in forest ecosystems is based on the estimate for 2010 as obtained from the Monte Carlo simulation. C stocks are based on forest condition level (plot-level) calculations, and, therefore, uncertainty analysis starts probabilistic sampling at the plot level. Uncertainty surrounding C density (Mg/ha) is defined for each of six C pools for each inventory plot. Live and standing dead tree C pools are generally assigned normal PDFs that represent total uncertainty of all trees measured on the plot, which varies according to species, number of trees, and per area representation. Error estimates for volume and the CRM for estimating biomass are not available, so an assumed 10 percent error on biomass from volume is applied to the volume portion of the estimate; error information in Jenkins et al. (2003) is applied to uncertainty about the additional components (e.g., top, leaves, and roots). Uniform PDFs with a range of ±90 percent of the average are used for those plots where C densities from similarly classified forest stands were applied.

Distributions for the remaining C pools are triangular or uniform, which partly reflects the lower level of information available about these estimates. The PDFs defined for these four pools were sampled as marginal distributions. Downed dead wood, understory, and litter are assigned triangular distributions with the mean at the expected value for each plot and the minimum and mode at 10 percent of the expected value. The use of these PDFs skewed to the right reflects the assumption that a small proportion of plots will have relatively high C densities. Soil organic C is defined as a uniform PDF at ±50 percent of the mean. Sub-state or state total C stocks associated with each survey are the cumulative sum of random samples from the plot-level PDFs, which are then appropriately expanded to population estimates. These expected values for each C pool include uncertainty associated with sampling, which is also incorporated in the Monte Carlo simulation. Sampling errors are determined according to methods described for the FIADB (Bechtold and Patterson 2005), are normally distributed, and are assigned a slight positive correlation between successive surveys for Monte Carlo sampling. More recent annual inventories are assigned higher sampling correlation between successive surveys based on the proportion of plot data jointly included in each. Errors for older inventory data are not available, and these surveys are assigned values consistent with those obtained from the FIADB.

Uncertainty about net C flux in HWP is based on Skog et al. (2004) and Skog (2008). Latin hypercube sampling is the basis for the HWP Monte Carlo simulation. Estimates of the HWP variables and HWP Contribution under the production approach are subject to many sources of uncertainty. An estimate of uncertainty is provided that evaluated the effect of uncertainty in 13 sources, including production and trade data and parameters used to make the estimate. Uncertain data and parameters include data on production and trade and factors to convert them to C, the Census-based estimate of C in housing in 2001, the EPA estimate of wood and paper discarded to SWDS for 1990 to 2000, the limits on decay of wood and paper in SWDS, the decay rate (half-life) of wood and paper in SWDS, the proportion of products produced in the United States made with wood harvested in the United States, and the rate of storage of wood and paper C in other countries that came from United States harvest, compared to storage in the United States.

A total of ten thousand samples are drawn from the PDF input to separately determine uncertainties about forest ecosystem and HWP flux before they are combined for a quantitative estimate of total forest C uncertainty (see uncertainty table in LULUCF chapter). Again this year, true Monte Carlo sampling is used for the forest ecosystem estimates (in contrast to Latin hypercube sampling, which was used in some previous estimates), and a part of the QA/QC process includes verifying that the PDFs are adequately sampled.

Emissions from Fires

CO_2

As stated in other sections, the forest inventory approach implicitly accounts for emissions due to disturbances. Net C stock change is estimated by subtracting consecutive C stock estimates. A disturbance removes C from the forest. The inventory data, on which net C stock estimates are based, already reflects the C loss because only C remaining in the forest is estimated. Estimating the CO_2 emissions from a disturbance such as fire and adding those emissions to the net CO_2 change in forests would result in double-counting the loss from fire because the inventory data already reflect the loss. There is interest, however, in the size of the CO_2 emissions from disturbances such as fire. The IPCC (2003) methodology and IPCC (2006) default combustion factor for wildfire were employed to estimate emissions from forest fires. Using the methodology provided in IPCC (2003), C emissions from forest fires were calculated as:

$$\text{C Emissions} = \text{Forest area burned (ha)} \times \text{Carbon density (Mg per ha of dry matter)}$$

$$\times \text{ Combustion efficiency (45\%)} \times \text{Mg to Tg conversion factor } (10^{-6})$$

where a default value of 0.45 from IPCC (2006) was assumed for the amount of biomass burned by wildfires as well as prescribed fires (combustion factor value).

This methodology was used to estimate emissions from both wildfires and prescribed fires occurring in the lower 48 states. Wildfire area statistics are available, but they include non-forest land, such as shrublands and grasslands. It was thus necessary to develop a rudimentary estimate of the percent of area burned in forest by multiplying the reported area burned by a ratio of total forest land area to the total area considered to be under protection from fire. Data on total area of forest land were obtained from FIA (USDA Forest Service 2013b**)**. Data on "total area considered to be under protection from fire" were available at the state level and obtained for the year 1990 from 1984-1990 Wildfire Statistics prepared by the USDA Forest Service (USDA Forest Service 1992). Data for years 1998, 2002, 2004, 2006, and 2008 were obtained from the National Association of State Foresters (NASF 2011, 2008, 2007a, 2007b, 2007c). For states where data were available for all five years, the 1990 value was assumed for years 1990 to 1994, values for 1998 were assumed for years 1995 to 1998, values for 2002 were assumed for years 1999 to 2002, values for 2004 were assumed for years 2003 and 2004, values for 2006 were assumed for years 2005 and 2006, and values for 2008 were assumed for years 2008 to 2012. For states where data were available for all years except 2002, 2004 data were assumed for years 1999 to 2004. For states where data were available for all years except 2004, 2006 data were assumed for 2003 through 2008. For years where data were available for all years except 2006, 2004 data were assumed for years 2003 to 2008. Since both the 1998 and 2006 values are missing from the NASF data for Alaska, the 1990 value was assumed for years 1990 to 1997, the 2002 value was assumed for years 1998 to 2002, the 2004 value was assumed for years 2003 to 2006, and the 2008 value was assumed for 2007 to 2012. Similarly, since the NASF data for New Mexico lacks values for 2002 and 2004, the 1990 value was assumed for years 1990–1995, while the 1998 value was assumed for year 1996 through 2001, the 2006 data were assumed for 2002 to 2006, and the 2008 value was assumed for all remaining years. Illinois has not reported data on wildland since 2002, so the 1990 value was assumed for years 1990–1995, while the 1998 value was assumed for years 1995 through 2001, and the 2002 value was assumed for all remaining years.

Total forestland area for the lower 48 states was divided by total area considered to be under protection from wildfire for the lower 48 states across the 1990 to 2012 time series to create ratios that were then applied to reported area burned to estimate the area of forestland burned for the lower 48 states. The ratio was applied to area burned from wildland fires and prescribed fires occurring in the lower 48 states. Reported area burned data for prescribed fires was available from 1998 to 2012 from the National Interagency Fire Center (NIFC 2013**)**. Data for the year 1998 was assumed for years 1990 to 1997.

Forest area burned data for Alaska are from the Alaska Department of Natural Resources (Alaska Department of Natural Resources 2008) or the Alaska Interagency Coordination Center (Alaska Interagency Coordination Center 2013). Data are acres of land which experienced fire activity on forest service land. The majority of wildfires in Alaska that occur on lands protected by the USDA Forest Service occur in the coastal areas (Southeast and South Central); as this is where the National Forest System land is located. According to expert judgment, the coastal area of Alaska included in this Inventory is mostly temperate rainforest and, therefore, there is little call for prescribed burns (Smith 2008). It was, thus, assumed that reported area burned for prescribed fires covers only prescribed fires in the lower 48 states.

The average C density in the lower 48 states for aboveground biomass C, dead wood C, and litter layer varied between 68.8 and 76.5 Mg/ha, according to annual (1990–2012) data from FIA. In order to estimate these annual C densities in the lower 48 states, the C contained in the aboveground, deadwood, and litter C pools was first summed for each state and year. The methodology assumes that wildfires burn only those pools, and leaves the belowground C and soil C un-burnt. The methodology estimates the C density value by taking a weighted average of these summed C pools in each state and year. The states' C values are weighted according to area of forestland present in each state and year compared with the total. A default value of 0.45 from IPCC (2006) was assumed for the amount of biomass burned by wildfire (combustion factor value). According to the estimates, wildfires in the lower 48 states emit between 6.5 and 76.1 Tg C. For Alaska, the average C density reported by the USDA Forest Service varies between 140.2 and 145.0 Mg/ha, based on data from FIA. In the case of wildfires in Alaska, Alaska's C pool values are used instead of a weighted average for states. These values translate into 0 to 0.1 Tg C emitted. Based on data from the USDA Forest Service, the average C density for prescribed fires varied between 24.8 and 25.7 Mg C/ha. For prescribed fires, the methodology assumes that only the litter and deadwood C pools burn. The weighted average C densities estimated for prescribed fires therefore only include the sum of these two pools, and excludes aboveground biomass. It is assumed that prescribed fires only occur in the lower 48 states (Smith 2008). The default value of 0.45 from IPCC (2006) for wildfires was also assumed for the amount of biomass burned by prescribed fires (combustion factor value). As a result, prescribed fires are estimated to emit between 0.5 and 7.5 Tg C.

Carbon density estimates for Mg C/ha were multiplied by estimates of forest area burned by year; the resulting estimates are displayed in Table A-258. C estimates were multiplied by 92.8 percent to account for the proportion of C emitted as CO_2 and by 3.67 (i.e., 44/12) to yield CO_2 units. Total CO_2 emissions for wildfires and prescribed fires in the lower 48 states and wildfires in Alaska in 2012 were estimated to be 242.7 Tg/yr.

Table A-258: Areas (Hectares) from Wildfire Statistics and Corresponding Estimates of Carbon and CO_2 (Tg/yr) Emissions for Wildfires and Prescribed Fires in the Lower 48 states and Wildfires in Alaska[1]

	Lower 48 States								Alaska			
	Wildfires				Prescribed Fires				Wildfires			
Year	Reported area burned[2] (ha)	Forest area burned[3] (ha)	Carbon emitted (Tg/yr)	CO_2 emitted (Tg/yr)	Reported area burned[2] (ha)	Forest area burned[3] (ha)	Carbon emitted (Tg/yr)	CO_2 emitted (Tg/yr)	Forest area burned[4] (acres)	Forest area burned (ha)	Carbon emitted (Tg/yr)	CO_2 emitted (Tg/yr)
1990	579,589	308,982	10	33	355,432	189,483	2	7	8	3	0.000	0.001
1991	486,807	260,103	8	28	355,432	189,909	2	7	557	225	0.014	0.048
1992	785,892	420,861	13	45	355,432	190,341	2	7	47	19	0.001	0.004
1993	438,865	235,533	7	25	355,432	190,755	2	7	110	45	0.003	0.010
1994	1,540,987	828,698	26	89	355,432	191,141	2	7	23	9	0.001	0.002
1995	727,051	427,354	14	46	355,432	208,920	2	8	7	3	0.000	0.001
1996	2,212,309	1,339,754	43	145	355,432	215,246	2	8	103	42	0.003	0.009
1997	335,914	203,738	6	22	355,432	215,576	2	8	33	13	0.001	0.003
1998	489,246	297,112	10	32	355,432	215,848	2	8	2	1	0.000	0.000
1999	1,869,918	1,143,390	37	125	806,780	493,318	6	19	7	3	0.000	0.001
2000	2,685,981	1,643,847	53	181	77,789	47,607	1	2	1	1	0.000	0.000
2001	1,356,830	830,972	27	92	667,428	408,757	5	16	2,078	841	0.054	0.184
2002	2,023,976	1,236,415	40	138	1,086,503	663,728	7	25	28	11	0.001	0.002
2003	1,358,986	728,786	24	81	1,147,695	615,476	7	24	17	7	0.000	0.002
2004	637,258	347,862	11	39	996,453	543,936	6	21	23	9	0.001	0.002
2005	1,629,067	953,384	32	108	934,965	547,172	6	21	353	143	0.009	0.031
2006	3,888,011	2,280,808	76	259	1,100,966	645,855	7	25	8	3	0.000	0.001
2007	3,512,122	1,797,232	60	205	1,274,383	652,131	7	25	2	1	0.000	0.000
2008	2,099,842	1,076,449	36	123	783,068	401,427	5	16	1	0	0.000	0.000
2009	1,201,996	617,272	21	71	1,024,306	526,021	6	20	22	9	0.001	0.002
2010	929,687	478,273	16	55	980,903	504,620	6	20	12	5	0.000	0.001
2011	3,406,788	1,755,690	60	205	855,025	440,638	5	17	5	2	0.000	0.000
2012	3,658,098	1,930,631	66	226	797,974	421,146	5	17	2	1	0.000	0.000

[1] Note that these emissions have already been accounted for in the estimates of net annual changes in C stocks, which accounts for the amount sequestered minus any emissions, including the assumption that combusted wood may continue to decay through time.

[2] National Interagency Fire Center (2013).

[3] Ratios calculated using forest land area estimates from FIA (USDA Forest Service 2012b) and wildland area under protection estimates from USDA Forest Service (1992) and the National Association of State Foresters (20011).

[4] 1990–2007 Alaskan forest fires data are from the Alaska Department of Natural Resources (2008). 2008–2011 data are from Alaska Interagency Coordination Center (2013).

Non-CO_2

Emissions of non-CO_2 gases from forest fires were estimated using the default IPCC (2003) methodology, IPCC (2006) emission ratios, and default IPCC (2006) combustion factor for wildfires. The default IPCC (2003) methodology and default IPCC (2006) combustion factor for wildfires were used to calculate the C emissions from forest fires as discussed above. Carbon dioxide emissions were estimated by multiplying total C emitted by the C to CO_2 conversion factor of 44/12 and by 92.8 percent, which is the estimated proportion of C emitted as CO_2 (Smith 2008). Emissions estimates for CH_4 and N_2O are calculated by multiplying the total estimated CO_2 emitted from forest burned by gas-specific emissions ratios from IPCC (2006). The models used are:

$$CH_4 \text{ Emissions} = (\text{C released}) \times 92.8\% \times (44/12) \times (CH_4 \text{ to } CO_2 \text{ emission ratio})$$

$$N_2O \text{ Emissions} = (\text{C released}) \times 92.8\% \times (44/12) \times (N_2O \text{ to } CO_2 \text{ emission ratio})$$

Where the CH_4 and N_2O to CO_2 emission ratios were derived from IPCC (2006), in Table A-256 below.

Table A- 259: Emission Factors for Extra Tropical Forest Burning and Emissions Ratios of CH_4 and N_2O to CO_2

Emission Factor (g per kg dry matter burned)[1]		Emissions Ratios	
CH_4	4.70	CH_4 to CO_2	0.003
N_2O	0.26	N_2O to CO_2	0.0002
CO_2	1,569	CO_2 to CO_2	1.000

[1] IPCC 2006

The resulting estimates are presented in Table A- 260.

Table A- 260: Estimated Carbon Released and Estimates of Non-CO_2 Emissions (Tg/yr) for U.S. forests[1]

Year	C emitted (Tg/yr)	CH_4 emitted (Tg/yr)	N_2O (Tg/yr)
1990	11.681	0.119	0.007
1991	10.218	0.104	0.006
1992	15.257	0.156	0.009
1993	9.511	0.097	0.005
1994	28.204	0.287	0.016
1995	15.839	0.161	0.009
1996	44.928	0.458	0.025
1997	8.916	0.091	0.005
1998	11.950	0.122	0.007
1999	42.381	0.432	0.024
2000	53.743	0.548	0.030
2001	31.681	0.323	0.018
2002	47.904	0.488	0.027
2003	30.901	0.315	0.017
2004	17.644	0.180	0.010
2005	37.851	0.386	0.021
2006	83.387	0.850	0.047
2007	67.663	0.690	0.038
2008	40.856	0.416	0.023
2009	26.935	0.275	0.015
2010	22.082	0.225	0.012
2011	65.181	0.664	0.037
2012	71.333	0.727	0.040

[1] Calculated based on C emission estimates in Table A-258 and default factors in IPCC (2003, 2006)

3.14. Methodology for Estimating CH_4 Emissions from Landfills

Landfill gas is a mixture of substances generated when bacteria decompose the organic materials contained in solid waste. By volume, landfill gas is about half CH_4 and half CO_2.[96] The amount and rate of CH_4 generation depends upon the quantity and composition of the landfilled material, as well as the surrounding landfill environment.

Not all CH_4 generated within a landfill is emitted to the atmosphere. The CH_4 can be extracted and either flared or utilized for energy, thus oxidizing the CH_4 to CO_2 during combustion. Of the remaining CH_4, a portion oxidizes to CO_2 as it travels through the top layer of the landfill cover. In general, landfill-related CO_2 emissions are of biogenic origin and primarily result from the decomposition, either aerobic or anaerobic, of organic matter such as food or yard wastes.[97] To estimate the amount of CH_4 produced in a landfill in a given year, information is needed on the type and quantity of waste in the landfill, as well as the landfill characteristics (e.g., size, aridity, waste density). This information is not available for the majority landfills in the United States. Consequently, to estimate CH_4 generation, a methodology was developed (i.e., the first order decay waste model) based on the quantity of waste placed in landfills nationwide each year and model parameters from the analysis of measured CH_4 generation rates for U.S. landfills with gas recovery systems.

From various studies and surveys of the generation and disposal of solid waste, estimates of the amount of waste placed in MSW and industrial waste landfills were developed. A database of measured CH_4 generation rates at MSW landfills with gas recovery systems was compiled and analyzed. The results of this analysis and other studies were used to develop an estimate of the CH_4 generation potential for use in the first order decay model. In addition, the analysis and other studies provided estimates of the CH_4 generation rate constant as a function of precipitation. The first order decay model was applied to annual waste disposal estimates for each year and for three ranges of precipitation to estimate CH_4 generation rates nationwide for the years of interest. Based on the organic content of industrial wastes and the estimates of the fraction of these wastes sent to industrial waste landfills, CH_4 emissions from industrial waste landfills were also estimated using the first order decay model. Total CH_4 emissions were estimated by adding the CH_4 from MSW and industrial landfills and subtracting the amounts recovered for energy or flaring at MSW landfills[98] and the amount oxidized in the soil at MSW and industrial landfills. The steps taken to estimate CH_4 emissions from U.S. landfills for the years 1990 through the current inventory year are discussed in greater detail below.

Figure A- 21 presents the CH_4 emissions process—from waste generation to emissions—in graphical format.

Step 1: Estimate Annual Quantities of Solid Waste Placed in Landfills

For 1989 to 2012, estimates of the annual quantity of waste placed in MSW landfills were developed from a survey of State agencies as reported in BioCycle's State of Garbage (SOG) in America reports (BioCycle 2010), adjusted to include U.S. territories.[99] The SOG survey is the only continually updated nationwide survey of waste disposed in landfills in the United States. Table A-261 shows estimates of waste quantities contributing to CH_4 emissions. The table shows SOG estimates of total waste generated and total waste landfilled (adjusted for U.S. territories) for various years over the 1990 to 2012 timeframe.

State-specific landfill waste generation data and a national average disposal factor for 1989 through 2008 were obtained from the SOG survey for every two years (i.e., 2002, 2004, 2006, and 2008 as published in BioCycle 2006, 2008, and 2010). A linear interpolation was used for the amount of waste generated in 2001, 2003, 2005, 2007, 2009, 2010, 2011, and 2012 because no BioCycle SOG surveys were published for those years. The most recent SOG survey was published in December 2010 representing 2008 data. Upon publication of the next SOG survey, the waste landfilled for 2009 through 2012 will be updated. Estimates of the quantity of waste landfilled from 1989 to the current inventory year are determined by applying a waste disposal factor to the total amount of waste generated (i.e., the SOG data). A waste disposal factor is determined for each year a SOG survey is published and is the ratio of the total amount of waste landfilled to the total amount of waste generated. The waste disposal factor is interpolated for the years in-between the

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[96] Typically, landfill gas also contains small amounts of nitrogen, oxygen, and hydrogen, less than 1 percent nonmethane volatile organic compounds (NMVOCs), and trace amounts of inorganic compounds.

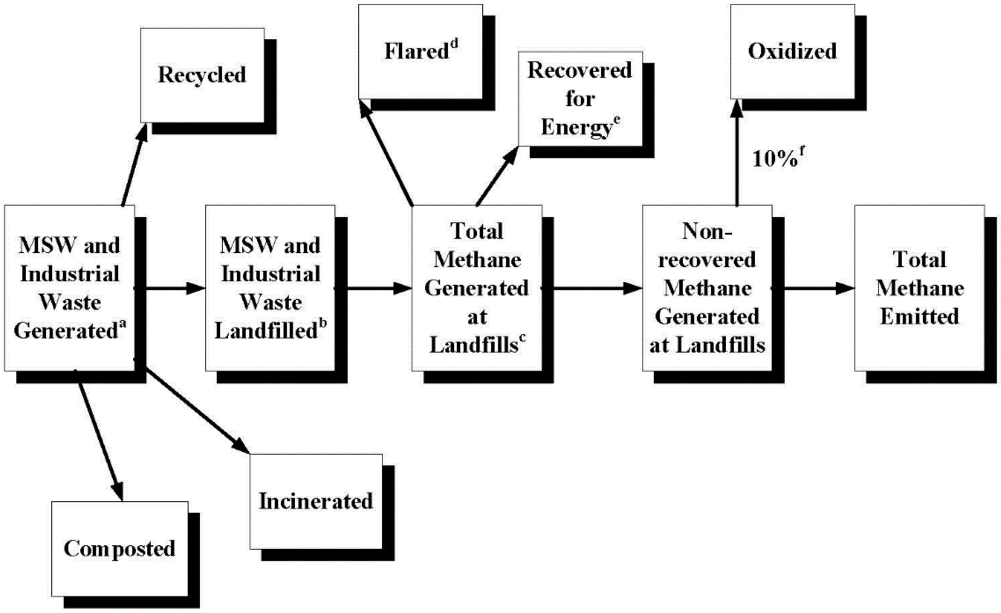
[97] See Box 8-1 "Biogenic Emissions and Sinks of Carbon" in the Waste chapter for additional background on how biogenic emissions of landfill CO_2 are addressed in the U.S. Inventory.

[98] Landfill gas recovery is only estimated for MSW landfills due to a lack of national data on industrial waste landfills. Approximately 1 percent of the industrial waste landfills reporting under the GHGRP have active landfill gas collection systems.

[99] Since the SOG survey does not include U.S. territories, waste landfilled in U.S. territories was estimated using population data for the U.S territories (U.S. Census Bureau 2013) and the per capita rate for waste landfilled from BioCycle (2010).

SOG surveys. Methodological changes have occurred over the time that the SOG survey has been published, and this has affected the fluctuating trends observed in the data (RTI 2013).

Figure A- 21: Methane Emissions Resulting from Landfilling Municipal and Industrial Waste



[a] BioCycle 2010 for MSW and activity factors for industrial waste.
[b] 1960 through 1988 based on EPA 1988 and EPA 1993; 1989 through 2006 based on BioCycle 2010.
[c] 2006 IPCC Guidelines – First Order Decay Model
[d] EIA 2007 and flare vendor database
[e] EIA 2007 and EPA (LMOP) 2007.
[f] 2006 IPCC Guidelines; Mancinelli and McKay 1985, Czepiel et al 1996

Table A-261: Solid Waste in MSW Landfills Contributing to CH_4 Emissions (Tg unless otherwise noted)

Description	1990	1995	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Total Waste Generated[a]	271	302	416	455	459	462	459	455	430	404	372	411	414	417
Percent of Wastes Landfilled[a]	77%	63%	63%	66%	65%	64%	64%	65%	67%	69%	69%	69%	69%	69%
Total Wastes Landfilled[a]	205	187	259	294	293	291	290	289	283	275	278	280	282	284
Waste in Place (30 years)[b]	4,671	5,054	5,562	5,562	5,709	5,852	5,991	6,126	6,257	6,378	6,488	6,598	6,707	6,814
Waste Contributing to Emissions[c]	6,808	7,772	9,340	9,340	9,632	9,924	10,214	10,503	10,786	11,061	11,339	11,619	11,901	12,185

[a] Source: *BioCycle* (2006, 2008, 2010), adjusted for missing data using U.S. Census Bureau (2009, 2013) population data and per capita disposal rate from *BioCycle*. The data, originally reported in short tons, are converted to metric tons. Estimates shown for 2001, 2003, 2005, 2007, 2009, 2010, 2011, and 2012 are based on an interpolation between survey years and the increase in population because there were no surveys in these years.

[b] This estimate represents the waste that has been in place for 30 years or less, which contributes about 90 percent of the CH_4 generation. Values are based on EPA (1993) for years 1940 to years 1988 (not presented in table) and *BioCycle* (2006, 2008, 2010) for years 1989 to 2012.

[c] This estimate represents the cumulative amount of waste that has been placed in landfills from 1940 to the year indicated and is the sum of the annual disposal rates used in the first order decay model. Values are based on EPA (1993).

Estimates of the annual quantity of waste placed in landfills from 1960 through 1988 were developed from EPA's 1993 Report to Congress (EPA 1993) and a 1986 survey of MSW landfills (EPA 1988). Based on the national survey and estimates of the growth of commercial, residential and other wastes, the annual quantity of waste placed in landfills averaged 127 million metric tons in the 1960s, 154 million metric tons in the 1970s, 190 million metric tons in the 1990s, and 285 million metric tons in the 2000's. Estimates of waste placed in landfills in the 1940s and 1950s were developed based on U.S. population for each year and the per capital disposal rates from the 1960s.

Step 2: Estimate CH_4 Generation at Municipal Solid Waste Landfills

The CH_4 generation was estimated from the integrated form of the first order decay (FOD) model using the procedures and spreadsheets from IPCC (2006) for estimating CH_4 emissions from solid waste disposal. The form of the FOD model that was applied incorporates a time delay of 6 months after waste disposal before the generation of CH_4 begins.

The input parameters needed for the FOD model equations are the mass of waste disposed each year, which was discussed in the previous section, degradable organic carbon (DOC), and the decay rate constant (k). The DOC is determined from the CH_4 generation potential (L_0 in m^3 CH_4/Mg waste), which is discussed in more detail in subsequent paragraphs, and the following equation:

$$DOC = [L_0 \times 6.74 \times 10^{-4}] \div [F \times 16/12 \times DOC_f \times MCF]$$

where,
DOC = degradable organic carbon (fraction, Gg C/Gg waste),
L_0 = CH_4 generation potential (m^3 CH_4/Mg waste),
6.74×10^{-4} = CH_4 density (Mg/m^3),
F = fraction of CH_4 by volume in generated landfill gas (equal to 0.5)
16/12 = molecular weight ratio CH_4/C,
DOC_f = fraction of DOC that can decompose in the anaerobic conditions in the landfill (fraction equal to 0.5 for MSW), and
MCF = methane correction factor for year of disposal (fraction equal to 1 for anaerobic managed sites).

The DOC value used in the CH_4 generation estimates from MSW landfills is 0.203 based on the CH_4 generation potential of 100 m^3 CH_4/Mg waste as described below. Data from a set of 52 representative landfills across the U.S. in different precipitation ranges were chosen to evaluate L_o, and ultimately the country-specific DOC value. The 2004 Chartwell Municipal Solid Waste Facility Directory confirmed that each of the 52 landfills chosen accepted or accepts both MSW and construction and demolition (C&D) waste (Chartwell 2004; RTI 2009).

The methane generation potential (L_o) varies with the amount of organic content of the waste material. A higher L_o occurrs with a higher content of organic waste. Waste composition data are not collected for all landfills nationwide; thus a default value must be used. Values for L_o were evaluated from landfill gas recovery data for this set of 52 landfills, which resulted in a best fit value for L_o of 99 m^3/Mg of waste (RTI 2004). This value compares favorably with a range of 50 to 162 (midrange of 106) m^3/Mg presented by Peer, Thorneloe, and Epperson (1993); a range of 87 to 91 m^3/Mg from a detailed analysis of 18 landfills sponsored by the Solid Waste Association of North America (SWANA 1998); and a value of 100 m^3/Mg recommended in EPA's compilation of emission factors (EPA 1998; EPA 2008) based on data from 21 landfills. Based on the results from these studies, a value of 100 m^3/Mg appears to be a reasonable best estimate to use in the FOD model for the national inventory.

The FOD model was applied to the gas recovery data for the 52 landfills to calculate the decay rate constant (k) directly for L_0 = 100 m^3/Mg. The rate constant was found to increase with annual average precipitation; consequently, average values of k were developed for three ranges of precipitation, shown in Table A- 262 and recommended in EPA's compilation of emission factors (EPA 2008).

Table A- 262: Average Values for Rate Constant (k) by Precipitation Range (yr^{-1})

Precipitation range (inches/year)	k (yr^{-1})
<20	0.020
20-40	0.038
>40	0.057

These values for k show reasonable agreement with the results of other studies. For example, EPA's compilation of emission factors (EPA 1998; EPA, 2008) recommends a value of 0.02 yr^{-1} for arid areas (less than 20 inches/year of precipitation) and 0.04 yr^{-1} for non-arid areas. The SWANA study of 18 landfills reported a range in values of k from 0.03 to 0.06 yr^{-1} based on CH_4 recovery data collected generally in the time frame of 1986 to 1995.

Using data collected primarily for the year 2000, the distribution of waste in place versus precipitation was developed from over 400 landfills (RTI 2004). A distribution was also developed for population vs. precipitation for comparison. The two distributions were very similar and indicated that population in areas or regions with a given precipitation range was a reasonable proxy for waste landfilled in regions with the same range of precipitation. Using U.S. Census data and rainfall data, the distributions of population versus rainfall were developed for each Census decade from 1950 through 2000. The distributions showed that the U.S. population has shifted to more arid areas over the past several decades. Consequently, the population distribution was used to apportion the waste landfilled in each decade according to the precipitation ranges developed for k, as shown in Table A-263.

Table A-263: Percent of U.S. Population within Precipitation Ranges (%)

Precipitation Range (inches/year)	1950	1960	1970	1980	1990	2000
<20	11	13	14	16	19	20
20-40	40	39	38	36	34	33
>40	49	48	48	48	47	47

Source: RTI (2004) using population data from the U.S. Bureau of Census and precipitation data from the National Climatic Data Center's National Oceanic and Atmospheric Administration.

In developing the Inventory, the proportion of waste disposed of in managed landfills versus open dumps prior to 1980 was re-evaluated. Based on the historical data presented by Mintz et al. (2003), a timeline was developed for the transition from the use of open dumps for solid waste disposed to the use of managed landfills. Based on this timeline, it was estimated that 6 percent of the waste that was land disposed in 1940 was disposed of in managed landfills and 94 percent was managed in open dumps. Between 1940 and 1980, the fraction of waste land disposed transitioned towards managed landfills until 100 percent of the waste was disposed of in managed landfills in 1980. For wastes disposed of in dumps, a methane correction factor (MCF) of 0.6 was used based on the recommended IPCC default value for uncharacterized land disposal (IPCC 2006); this MCF is equivalent to assuming 50 percent of the open dumps are deep and 50 percent are shallow. The recommended IPCC default value for the MCF for managed landfills of 1 was used for the managed landfills (IPCC 2006).

Step 3: Estimate CH_4 Generation at Industrial Landfills

Industrial waste landfills receive waste from factories, processing plants, and other manufacturing activities. In national inventories prior to the 1990 through 2005 inventory, CH_4 generation at industrial landfills was estimated as seven percent of the total CH_4 generation from MSW landfills, based on a study conducted by EPA (1993). For the 1990 through 2007 and current inventories, the methodology was updated and improved by using activity factors (industrial production levels) to estimate the amount of industrial waste landfilled each year and by applying the FOD model to estimate CH_4 generation. A nationwide survey of industrial waste landfills found that over 99 percent of the organic waste placed in industrial landfills originated from two industries: food processing (meat, vegetables, fruits) and pulp and paper (EPA 1993). Data for annual nationwide production for the food processing and pulp and paper industries were taken from industry and government sources for recent years; estimates were developed for production for the earlier years for which data were not available. For the pulp and paper industry, production data published by the Lockwood-Post's Directory were used for years 1990 to 2001 and production data published by the U.S. Department of Agriculture were used for years 2002 through 2011. An extrapolation based on U.S. real gross domestic product was used for years 1940 through 1964. For the food processing industry, production levels were obtained or developed from the U.S. Department of Agriculture for the years 1990 through 2011 (ERG 2013). An extrapolation based on U.S. population was used for the years 1940 through 1989.

In addition to production data for the pulp and paper and food processing industries, the following inputs were needed to use the FOD model for estimating CH_4 generation from industrial landfills: 1) quantity of waste that is disposed in industrial waste landfills (as a function of production), 2) CH_4 generation potential (L_0) or DOC, and 3) FOD decay constant (k). Research into waste generation and disposal in landfills for the pulp and paper industry indicated that the quantity of waste landfilled was about 0.050 Mg/Mg of product compared to 0.046 Mg/Mg product for the food processing industry (RTI 2006). These factors were applied to estimates of annual production to estimate annual waste disposal in landfills. Estimates for DOC were derived from available data (Kraft and Orender, 1993; NCASI 2008; Flores et al. 1999). The DOC value for industrial pulp and paper waste is estimated at 0.20 (L_o of 99 m^3/Mg); the DOC value for industrial food waste is estimated as 0.26 (L_o of 128 m^3/Mg) (RTI 2008). Estimates for k were taken from the default values in the 2006 IPCC Guidelines; the value of k given for food waste with disposal in a wet temperate climate is 0.19 yr^{-1}, and the value given for paper waste is 0.06 yr^{-1}.

A literature review was conducted for the 1990 to 2010 inventory year with the intent of updating values for L_o and k in the pulp and paper industry. Where pulp and paper mill wastewater treatment residuals or sludge are the primary constituents of pulp and paper waste landfilled, values for k range from 0.01/yr to 0.1/yr, while values for L_o range from 50 m^3/Mg to 200 m^3/Mg.[100] Values for these factors are highly variable and are dependent on the soil moisture content, which is generally related to rainfall amounts. At this time, sufficient data were not obtained to warrant a change for the current inventory year. EPA is considering an update to the L_o and k values for the pulp and paper sector and will work with stakeholders to gather data and other feedback on potential changes to these values.

As with MSW landfills, a similar trend in disposal practices from open dumps to managed landfills was expected for industrial waste landfills; therefore, the same time line that was developed for MSW landfills was applied to the industrial landfills to estimate the average MCF. That is, between 1940 and 1980, the fraction of waste that was land disposed transitioned from 6 percent managed landfills in 1940 and 94 percent open dumps to 100 percent managed landfills in 1980 and on. For wastes disposed of in dumps, an MCF of 0.6 was used and for wastes disposed of in managed landfills, an MCF of 1 was used, based on the recommended IPCC default values (IPCC 2006).

The parameters discussed above were used in the integrated form of the FOD model to estimate CH_4 generation from industrial waste landfills.

Step 4: Estimate CH_4 Emissions Avoided

The estimate of CH_4 emissions avoided (e.g., combusted) was based on landfill-specific data on landfill gas-to-energy (LFGTE) projects and flares. A destruction efficiency of 99 percent was applied to CH_4 recovered to estimate CH_4 emissions avoided. The value for efficiency was selected based on the range of efficiencies (86 to 99+ percent) recommended for flares in EPA's AP-42 Compilation of Air Pollutant Emission Factors, Draft Chapter 2.4, Table 2.4-3 (EPA 2008). A typical value of 97.7 percent was presented for the non-methane components (i.e., volatile organic compounds and non-methane organic compounds) in test results (EPA 2008). An arithmetic average of 98.3 percent and a median value of 99 percent are derived from the test results presented in EPA 2008. Thus, a value of 99 percent for the destruction efficiency of flares has been used in Inventory methodology. Other data sources supporting a 99 percent destruction efficiency include those used to establish new source performance standards (NSPS) for landfills and in recommendations for closed flares used in the Landfill Methane Outreach Program (LMOP).

Step 4a: Estimate CH_4 Emissions Avoided Through Landfill Gas-to-Energy (LFGTE) Projects

The quantity of CH_4 avoided due to LFGTE systems was estimated based on information from two sources: (1) a database developed by the Energy Information Administration (EIA) for the voluntary reporting of greenhouse gases (EIA 2007) and (2) a database compiled by LMOP (EPA 2012). The EIA database included location information for landfills with LFGTE projects, estimates of CH_4 reductions, descriptions of the projects, and information on the methodology used to determine the CH_4 reductions. Generally the CH_4 reductions for each reporting year were based on the measured amount of landfill gas collected and the percent CH_4 in the gas. For the LMOP database, data on landfill gas flow and energy generation (i.e., MW capacity) were used to estimate the total direct CH_4 emissions avoided due to the LFGTE project. Detailed information on the landfill name, owner or operator, city, and state were available for both the

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[100] Sources reviewed included Heath et al. 2010; Miner 2008; Skog 2008; Upton et al. 2008; Barlaz 2006; Sonne 2006; NCASI 2005; and Skog 2000.

EIA and LMOP databases; consequently, it was straightforward to identify landfills that were in both databases. The EIA database was given priority because reductions were reported for each year and were based on direct measurements. Landfills in the LMOP database that were also in the EIA database were dropped to avoid double counting.

Step 4b: Estimate CH_4 Emissions Avoided Through Flaring

The quantity of CH_4 flared was based on data from the EIA database and on information provided by flaring equipment vendors. To avoid double-counting, flares associated with landfills in the EIA and LMOP databases were excluded from the flare vendor database. As with the LFGTE projects, reductions from flaring landfill gas in the EIA database were based on measuring the volume of gas collected and the percent of CH_4 in the gas. The information provided by the flare vendors included information on the number of flares, flare design flow rates or flare dimensions, year of installation, and generally the city and state location of the landfill. When a range of design flare flow rates was provided by the flare vendor, the median landfill gas flow rate was used to estimate CH_4 recovered from each remaining flare (i.e., for each flare not associated with a landfill in the EIA or LMOP databases). Several vendors provided information on the size of the flare rather than the flare design gas flow rate. To estimate a median flare gas flow rate for flares associated with these vendors, the size of the flare was matched with the size and corresponding flow rates provided by other vendors. Some flare vendors reported the maximum capacity of the flare. An analysis of flare capacity versus measured CH_4 flow rates from the EIA database showed that the flares operated at 51 percent of capacity when averaged over the time series and at 72 percent of capacity for the highest flow rate for a given year. For those cases when the flare vendor supplied maximum capacity, the actual flow was estimated as 50 percent of capacity. Total CH_4 avoided through flaring from the flare vendor database was estimated by summing the estimates of CH_4 recovered by each flare for each year.

Step 4c: Reduce CH_4 Emissions Avoided Through Flaring

As mentioned in Step 4b, flares in the flare vendor database associated with landfills in the EIA and LMOP databases were excluded from the flare reduction estimates in the flare vendor database. If comprehensive data on flares were available, each LFGTE project in the EIA and LMOP databases would have an identified flare because it is assumed that most LFGTE projects have flares. However, given that the flare vendor data only covers approximately 50 to 75 percent of the flare population, an associated flare was not identified for all LFGTE projects. These LFGTE projects likely have flares, yet flares were unable to be identified for one of two reasons: 1) inadequate identifier information in the flare vendor data; or 2) a lack of the flare in the flare vendor database. For those projects for which a flare was not identified due to inadequate information, CH_4 avoided would be overestimated, as both the CH_4 avoided from flaring and the LFGTE project would be counted. To avoid overestimating emissions avoided from flaring, the CH_4 avoided from LFGTE projects with no identified flares was determined and the flaring estimate from the flare vendor database was reduced by this quantity (referred to as a flare correction factor) on a state-by-state basis. This step likely underestimates CH_4 avoided due to flaring but was applied to be conservative in the estimates of CH_4 emissions avoided.

Additional effort was undertaken to improve the methodology behind the flare correction factor for the 1990-2009 Inventory to reduce the total number of flares in the flare vendor database that were not matched (512) to landfills and/or LFGTE projects in the EIA and LMOP databases. Each flare in the flare vendor database not associated with a LFGTE project in the EIA or LMOP databases was investigated to determine if it could be matched to either a landfill in the EIA database or a LFGTE project in the LMOP database. For some unmatched flares, the location information was missing or incorrectly transferred to the flare vendor database. In other instances, the landfill names were slightly different between what the flare vendor provided and the actual landfill name as listed in the EIA and LMOP databases.

It was found that a large majority of the unmatched flares are associated with landfills in LMOP that are currently flaring, but are also considering LFGTE. These landfills projects considering a LFGTE project are labeled as candidate, potential, or construction in the LMOP database. The flare vendor database was improved to match flares with operational, shutdown as well as candidate, potential, and construction LFGTE projects, thereby reducing the total number of unidentified flares in the flare vendor database, all of which are used in the flare correction factor. The results of this effort significantly decreased the number of flares used in the flare correction factor, and consequently, increased recovered flare emissions, and decreased net emissions from landfills for the 1990-2009 Inventory. The revised state-by-state flare correction factors were applied to the entire Inventory time series.

Step 5: Estimate CH_4 Oxidation

A portion of the CH_4 escaping from a landfill oxidizes to CO_2 in the top layer of the soil. The amount of oxidation depends upon the characteristics of the soil and the environment. For purposes of this analysis, it was assumed that of the CH_4 generated, minus the amount of gas recovered for flaring or LFGTE projects, 10 percent was oxidized in the soil (Jensen and Pipatti 2002; Mancinelli and McKay 1985; Czepiel et al 1996). The factor of 10 percent is consistent with the value recommended in the 2006 IPCC revised guidelines for managed and covered landfills, and was therefore applied to the estimates of CH_4 generation minus recovery for both MSW and industrial landfills

A literature review was conducted in 2011 (RTI 2011) to provide recommendations for the most appropriate oxidation rate assumptions. It was found that oxidation values are highly variable and range from zero to over 100 percent (i.e., the landfill is considered to be an atmospheric sink by virtue of the landfill gas extraction system pulling atmospheric methane down through the cover). There is considerable uncertainty and variability surrounding estimates of the rate of oxidation because oxidation is difficult to measure and varies considerably with the presence of a gas collection system, thickness and type of the cover material, size and area of the landfill, climate, and the presence of cracks and/or fissures in the cover material through which methane can escape. IPCC (2006) notes that test results from field and laboratory studies may lead to over-estimations of oxidation in landfill cover soils because they largely determine oxidation using uniform and homogeneous soil layers. In addition, a number of studies note that gas escapes more readily through the side slopes of a landfill as compared to moving through the cover thus complicating the correlation between oxidation and cover type or gas recovery.

Sites with landfill gas collection systems are generally designed and managed better to improve gas recovery. More recent research (2006 to 2012) on landfill cover methane oxidation has relied on stable isotope techniques that may provide a more reliable measure of oxidation. Results from this recent research consistently point to higher cover soil methane oxidation rates than the IPCC (2006) default of 10 percent. A continued effort will be made to review the peer-reviewed literature to better understand how climate, cover type, and gas recovery influence the rate of oxidation at active and closed landfills. At this time, the IPCC recommended oxidation factor of 10 percent will continue to be used for all landfills.

Step 6: Estimate Total CH_4 Emissions

Total CH_4 emissions were calculated by adding emissions from MSW and industrial landfills, and subtracting CH_4 recovered and oxidized, as shown in Table A- 264.

Table A- 264: CH_4 Emissions from Landfills (Gg)

Activity	1990	1995	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
MSW CH_4 Generation	8,219	9,132	10,068	10,367	10,754	11,120	11,466	11,793	12,103	12,280	12,623	12,863	13,099	13,331
Industrial CH_4 Generation	553	617	704	711	719	724	732	736	741	748	753	756	758	758
Potential Emissions	**8,772**	**9,749**	**10,772**	**11,078**	**11,473**	**11,844**	**12,198**	**12,530**	**12,844**	**13,127**	**13,377**	**13,619**	**13,857**	**14,089**
Landfill Gas-to-Energy	(634)	(1,070)	(2,565)	(2,554)	(2,520)	(2,630)	(2,660)	(2,766)	(2,980)	(3,189)	(3,532)	(3,927)	(4,190)	(4,608)
Flare	(321)	(1,298)	(2,505)	(2,772)	(2,920)	(3,399)	(3,606)	(3,880)	(3,961)	(3,880)	(3,743)	(3,876)	(3,986)	(4,040)
Emissions Avoided	**(954)**	**(2,368)**	**(5,070)**	**(5,326)**	**(5,440)**	**(6,029)**	**(6,266)**	**(6,646)**	**(6,942)**	**(7,079)**	**(7,274)**	**(7,803)**	**(8,177)**	**(8,648)**
Oxidation at MSW Landfills	**(726)**	**(676)**	**(500)**	**(504)**	**(531)**	**(5109)**	**(520)**	**(515)**	**(516)**	**(530)**	**(535)**	**(506)**	**(492)**	**(468)**
Oxidation at Industrial Landfills	**(55)**	**(62)**	**(70)**	**(71)**	**(72)**	**(72)**	**(73)**	**(74)**	**(74)**	**(75)**	**(75)**	**(76)**	**(76)**	**(76)**
Net Emissions	**7,036**	**6,643**	**5,132**	**5,177**	**5,430**	**5,233**	**5,339**	**5,295**	**5,312**	**5,444**	**5,492**	**5,234**	**5,112**	**4,897**

Note: Totals may not sum exactly to the last significant figure due to rounding.

Note: MSW generation in Table A-248 represents emissions before oxidation. In other tables throughout the text, MSW generation estimates account for oxidation

Note: Parentheses denote negative values.

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ANNEX 4 IPCC Reference Approach for Estimating CO_2 Emissions from Fossil Fuel Combustion

It is possible to estimate carbon dioxide (CO_2) emissions from fossil fuel consumption using alternative methodologies and different data sources than those described in the Estimating Emissions from Fossil Fuel Combustion Annex. For example, the UNFCCC reporting guidelines request that countries, in addition to their "bottom-up" sectoral methodology, complete a "top-down" Reference Approach for estimating CO_2 emissions from fossil fuel combustion. Section 1.3 of the *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reporting Instructions* states, "If a detailed, Sectoral Approach for energy has been used for the estimation of CO_2 from fuel combustion you are still asked to complete…the Reference Approach…for verification purposes" (IPCC/UNEP/OECD/IEA 1997). This reference method estimates fossil fuel consumption by adjusting national aggregate fuel production data for imports, exports, and stock changes rather than relying on end-user consumption surveys. The basic principle is that once C-based fuels are brought into a national economy, they are either saved in some way (e.g., stored in products, kept in fuel stocks, or left unoxidized in ash) or combusted, and therefore the C in them is oxidized and released into the atmosphere. Accounting for actual consumption of fuels at the sectoral or sub-national level is not required. The following discussion provides the detailed calculations for estimating CO_2 emissions from fossil fuel combustion from the United States using the IPCC-recommended Reference Approach.

Step 1: Collect and Assemble Data in Proper Format

To ensure the comparability of national inventories, the IPCC has recommended that countries report energy data using the International Energy Agency (IEA) reporting convention. National energy statistics were collected in physical units from several EIA documents in order to obtain the necessary data on production, imports, exports, and stock changes.

It was necessary to make a number of modifications to these data to generate more accurate apparent consumption estimates of these fuels. The first modification adjusts for consumption of fossil fuel feedstocks accounted for in the Industrial Processes chapter, which include the following: unspecified coal for coal coke used in iron and steel production; natural gas, distillate fuel, and coal used in iron and steel production; natural gas used for ammonia production; petroleum coke used in the production of aluminum, ferroalloys, titanium dioxide, ammonia, and silicon carbide; and other oil and residual fuel oil used in the manufacture of C black. The second modification adjusts for the fact that EIA energy statistics include synthetic natural gas in coal and natural gas data. The third modification adjusts for the inclusion of ethanol in motor gasoline statistics. Ethanol is a biofuel, and net carbon fluxes from changes in biogenic carbon reservoirs in croplands are accounted for in the estimates for Land Use, Land-Use Change, and Forestry (see Chapter 7). The fourth modification adjusts for consumption of bunker fuels, which refer to quantities of fuels used for international transportation estimated separately from U.S. totals. The fifth modification consists of the addition of U.S. territories data that are typically excluded from the national aggregate energy statistics. The territories include Puerto Rico, U.S. Virgin Islands, Guam, American Samoa, Wake Island, and U.S. Pacific Islands. These data, as well as the production, import, export, and stock change statistics, are presented in Table A- 265.

The C content of fuel varies with the fuel's heat content. Therefore, for an accurate estimation of CO_2 emissions, fuel statistics were provided on an energy content basis (e.g., Btu or joules). Because detailed fuel production statistics are typically provided in physical units (as in Table A- 265 for 2012), they were converted to units of energy before CO_2 emissions were calculated. Fuel statistics were converted to their energy equivalents by using conversion factors provided by EIA. These factors and their data sources are displayed in Table A- 266. The resulting fuel type-specific energy data for 2012 are provided in Table A- 267.

Step 2: Estimate Apparent Fuel Consumption

The next step of the IPCC Reference Approach is to estimate "apparent consumption" of fuels within the country. This requires a balance of primary fuels produced, plus imports, minus exports, and adjusting for stock changes. In this way, C enters an economy through energy production and imports (and decreases in fuel stocks) and is transferred out of the country through exports (and increases in fuel stocks). Thus, apparent consumption of primary fuels (including crude oil, natural gas liquids, anthracite, bituminous, subbituminous and lignite coal, and natural gas) can be calculated as follows:

Apparent Consumption = Production + Imports - Exports - Stock Change

Flows of secondary fuels (e.g., gasoline, residual fuel, coke) should be added to primary apparent consumption. The production of secondary fuels, however, should be ignored in the calculations of apparent consumption since the C contained in these fuels is already accounted for in the supply of primary fuels from which they were derived (e.g., the estimate for apparent consumption of crude oil already contains the C from which gasoline would be refined). Flows of secondary fuels should therefore be calculated as follows:

Secondary Consumption = Imports - Exports - Stock Change

Note that this calculation can result in negative numbers for apparent consumption of secondary fuels. This result is perfectly acceptable since it merely indicates a net export or stock increase in the country of that fuel when domestic production is not considered.

Next, the apparent consumption and secondary consumption need to be adjusted for feedstock uses of fuels accounted for in the Industrial Processes chapter, international bunker fuels, and U.S. territory fuel consumption. Bunker fuels and feedstocks accounted for in the Industrial Processes chapter are subtracted from these estimates, while fuel consumption in U.S. territories is added.

The IPCC Reference Approach calls for estimating apparent fuel consumption before converting to a common energy unit. However, certain primary fuels in the United States (e.g., natural gas and steam coal) have separate conversion factors for production, imports, exports, and stock changes. In these cases, it is not appropriate to multiply apparent consumption by a single conversion factor since each of its components has different heat contents. Therefore, United States fuel statistics were converted to their heat equivalents before estimating apparent consumption. Results are provided in Table A- 266.

Step 3: Estimate Carbon Emissions

Once apparent consumption is estimated, the remaining calculations are similar to those for the “bottom-up” Sectoral Approach (see Estimating Emissions from Fossil Fuel Combustion Annex). Potential CO_2 emissions were estimated using fuel-specific C coefficients (see Table A- 267).[101] The C in products from non-energy uses of fossil fuels (e.g., plastics or asphalt) was then estimated and subtracted (see Table A-269). This step differs from the Sectoral Approach in that emissions from both fuel combustion and non-energy uses are accounted for in this approach. Finally, to obtain actual CO_2 emissions, net emissions were adjusted for any C that remained unoxidized as a result of incomplete combustion (e.g., C contained in ash or soot). The fraction oxidized was assumed to be 100 percent for petroleum, coal, and natural gas based on guidance in IPCC (2006) (see Estimating Emissions from Fossil Fuel Combustion Annex).

Step 4: Convert to CO_2 Emissions

Because the IPCC reporting guidelines recommend that countries report greenhouse gas emissions on a full molecular weight basis, the final step in estimating CO_2 emissions from fossil fuel consumption was converting from units of C to units of CO_2. Actual C emissions were multiplied by the molecular-to-atomic weight ratio of CO_2 to C (44/12) to obtain total CO_2 emitted from fossil fuel combustion in teragrams (Tg). The results are contained in Table A- 268.

Comparison Between Sectoral and Reference Approaches

These two alternative approaches can both produce reliable estimates that are comparable within a few percent. Note that the reference approach *includes* emissions from non-energy uses. Therefore, these totals should be compared to the aggregation of fuel use and emission totals from Emissions of CO_2 from Fossil Fuel Combustion and Carbon Emitted from Non-Energy Uses of Fossil Fuels Annexes. These two sections together are henceforth referred to as the Sectoral Approach. Other than this distinction, the major difference between methodologies employed by each approach lies in the energy data used to derive C emissions (i.e., the actual surveyed consumption for the Sectoral Approach versus apparent consumption derived for the Reference Approach). In theory, both approaches should yield identical results. In practice, however, slight discrepancies occur. An examination of past CRF table submissions during UNFCCC reviews has highlighted the need to further investigate these discrepancies. The investigation found that the most recent (two to three) inventory years tend to have larger differences in consumption and emissions estimates occurring earlier in the time series. This is a result of annual energy consumption data revisions in the EIA energy statistics, and the revisions have the

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[101] Carbon coefficients from EIA were used wherever possible. Because EIA did not provide coefficients for coal, the IPCC-recommended emission factors were used in the top-down calculations for these fuels. See notes in Table A- 268 for more specific source information.

greatest impact on the most recent few years of inventory estimates. As a result, the differences between the sectoral and reference approach decrease and are resolved over time. For the United States, these differences are discussed below.

Differences in Total Amount of Energy Consumed

Table A-271 summarizes the differences between the Reference and Sectoral approaches in estimating total energy consumption in the United States. Although theoretically the two methods should arrive at the same estimate for U.S. energy consumption, the Reference Approach provides an energy consumption total that is 1.1 percent lower than the Sectoral Approach for 2012. The greatest differences lie in lower estimates for petroleum and coal consumption for the Reference Approach (1.9 percent and 1.6 percent, respectively) and higher estimates for natural gas consumption for the Reference Approach (0.4 percent).

There are several potential sources for the discrepancies in consumption estimates:

- *Product Definitions.* The fuel categories in the Reference Approach are different from those used in the Sectoral Approach, particularly for petroleum. For example, the Reference Approach estimates apparent consumption for crude oil. Crude oil is not typically consumed directly, but refined into other products. As a result, the United States does not focus on estimating the energy content of the various grades of crude oil, but rather estimating the energy content of the various products resulting from crude oil refining. The United States does not believe that estimating apparent consumption for crude oil, and the resulting energy content of the crude oil, is the most reliable method for the United States to estimate its energy consumption. Other differences in product definitions include using sector-specific coal statistics in the Sectoral Approach (i.e., residential, commercial, industrial coking, industrial other, and transportation coal), while the Reference Approach characterizes coal by rank (i.e. anthracite, bituminous, etc.). Also, the liquefied petroleum gas (LPG) statistics used in the bottom-up calculations are actually a composite category composed of natural gas liquids (NGL) and LPG.
- *Heat Equivalents.* It can be difficult to obtain heat equivalents for certain fuel types, particularly for categories such as "crude oil" where the key statistics are derived from thousands of producers in the United States and abroad.
- *Possible inconsistencies in U.S. Energy Data.* The United States has not focused its energy data collection efforts on obtaining the type of aggregated information used in the Reference Approach. Rather, the United States believes that its emphasis on collection of detailed energy consumption data is a more accurate methodology for the United States to obtain reliable energy data. Therefore, top-down statistics used in the Reference Approach may not be as accurately collected as bottom-up statistics applied to the Sectoral Approach.
- *Balancing Item.* The Reference Approach uses *apparent* consumption estimates while the Sectoral Approach uses *reported* consumption estimates. While these numbers should be equal, there always seems to be a slight difference that is often accounted for in energy statistics as a “balancing item.”

Differences in Estimated CO_2 Emissions

Given these differences in energy consumption data, the next step for each methodology involved estimating emissions of CO_2. Table A-272 summarizes the differences between the two methods in estimated C emissions.

As mentioned above, for 2012, the Reference Approach resulted in a 1.1 percent lower estimate of energy consumption in the United States than the Sectoral Approach. The resulting emissions estimate for the Reference Approach was 0.6 percent lower. Estimates of natural gas emissions from the Reference Approach are higher (0.4 percent), and coal and petroleum emission estimates are lower (1.7 percent and 0.4 percent, respectively) than the Sectoral Approach. Potential reasons for these differences may include:

- *Product Definitions.* Coal data is aggregated differently in each methodology, as noted above. The format used for the Sectoral Approach likely results in more accurate estimates than in the Reference Approach. Also, the Reference Approach relies on a "crude oil" category for determining petroleum-related emissions. Given the many sources of crude oil in the United States, it is not an easy matter to track potential differences in C content between many different sources of crude; particularly since information on the C content of crude oil is not regularly collected.
- *Carbon Coefficients.* The Reference Approach relies on several default C coefficients by rank provided by IPCC (IPCC/UNEP/OECD/IEA 1997), while the Sectoral Approach uses annually updated category-specific coefficients by sector that are likely to be more accurate. Also, as noted above, the C coefficient for crude oil is more uncertain than that for specific secondary petroleum products, given the many sources and grades of crude oil consumed in the United States.

Although the two approaches produce similar results, the United States believes that the “bottom-up” Sectoral Approach provides a more accurate assessment of CO_2 emissions at the fuel level. This improvement in accuracy is largely a result of the data collection techniques used in the United States, where there has been more emphasis on obtaining the detailed products-based information used in the Sectoral Approach than obtaining the aggregated energy flow data used in the Reference Approach. The United States believes that it is valuable to understand both methods.

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Table A- 265: 2012 U.S. Energy Statistics (Physical Units)

Fuel Category (Units)	Fuel Type	Production	Imports	Exports	Stock Change	Adjustment	Bunkers	U.S. Territories
Solid Fuels (Thousand Short Tons)	Anthracite Coal	2,133	[a]	[a]	[a]			
	Bituminous Coal	465,091	[a]	[a]	[a]			
	Sub-bituminous Coal	474,378	[a]	[a]	[a]	367		
	Lignite	75,219	[a]	[a]	[a]	4,605		
	Coke		1,418	974	38			
	Unspecified Coal		9,159	125,746	7,980	2,678		1,653
Gas Fuels (Million Cubic Feet)	Natural Gas	24,023,327	3,137,789	1,618,828	8,840	296,664		26,486
Liquid Fuels (Thousand Barrels)	Crude Oil	2,374,021	3,120,755	24,693	34,134			
	Nat Gas Liquids and LRGs	881,306	62,192	115,054	23,892			3,107
	Other Liquids		459,916	78,359	18,575			
	Motor Gasoline	38,449	16,147	149,657	(5,420)			46,419
	Aviation Gasoline		29		(88)			
	Kerosene		464	1,994	(690)			1,273
	Jet Fuel		19,993	48,458	(1,863)		157,243	9,939
	Distillate Fuel		46,179	368,633	(14,403)	458	69,784	22,821
	Residual Fuel		93,672	142,167	(238)	10,000	48	26,048
	Naphtha for petrochemical feedstocks		11,588		148			
	Petroleum Coke		4,419	184,167	750	7,894		
	Other Oil for petrochemical feedstocks		14,504		457	5,890		
	Special Naphthas		4,496	17,847	167			
	Lubricants		11,391	27,326	(253)			172
	Waxes		1,837	1,982	52			
	Asphalt/Road Oil		11,196	11,152	2,486			
	Still Gas							
	Misc. Products		74	1,474	(17)			21,135

[a] Included in Unspecified Coal

Data Sources: Solid and Gas Fuels: EIA (2014); Liquid Fuels: EIA (1995-2013).

Table A- 266: Conversion Factors to Energy Units (Heat Equivalents)

Fuel Category (Units)	Fuel Type	Production	Imports	Exports	Stock Change	Adjustment	Bunkers	U.S. Territories
Solid Fuels (Million Btu/Short Ton)	Anthracite Coal	22.57						
	Bituminous Coal	23.89						
	Sub-bituminous Coal	17.14				28.16		
	Lignite	12.87				12.87		
	Coke		23.13	24.55	23.13			
	Unspecified		25.00	25.97	20.86	183.13		25.14
Natural Gas (BTU/Cubic Foot)		1,022	1,025	1,009	1,024	1,024		1,024
Liquid Fuels (Million Btu/Barrel)	Crude Oil	5.80	6.17	5.58	5.58		5.58	5.58
	Nat Gas Liquids and LRGs	3.68	3.68	3.68	3.68		3.68	3.68
	Other Liquids	5.83	5.83	5.83	5.83		5.83	5.83
	Motor Gasoline	5.22	5.22	5.22	5.22	5.22	5.22	5.22
	Aviation Gasoline		5.05	5.05	5.05		5.05	5.05
	Kerosene		5.67	5.67	5.67		5.67	5.67
	Jet Fuel		5.67	5.67	5.67		5.83	5.67
	Distillate Fuel		5.83	5.83	5.83	5.83	5.83	5.83
	Residual Oil		6.29	6.29	6.29	6.29	6.29	6.29
	Naphtha for petrochemical feedstocks		5.25	5.25	5.25		5.25	5.25
	Petroleum Coke		6.02	6.02	6.02	6.02	6.02	6.02
	Other Oil for petrochemical feedstocks		5.83	5.83	5.83	5.83	5.83	5.83
	Special Naphthas		5.25	5.25	5.25		5.25	5.25
	Lubricants		6.07	6.07	6.07		6.07	6.07
	Waxes		5.54	5.54	5.54		5.54	5.54
	Asphalt/Road Oil		6.64	6.64	6.64		6.64	6.64
	Still Gas		6.00	6.00	6.00		6.00	6.00
	Misc. Products		5.80	5.80	5.80		5.80	5.80

Data Sources: Coal and lignite production: EIA (1992); Unspecified Solid Fuels, Coke, Natural Gas and Petroleum Products: EIA (2014).

Table A- 267: 2012 Apparent Consumption of Fossil Fuels (TBtu)

Fuel Category	Fuel Type	Production	Imports	Exports	Stock Change	Adjustment	Bunkers	U.S. Territories	Apparent Consumption
Solid Fuels	Anthracite Coal	48.2							**48.2**
	Bituminous Coal	11,111.0							**11,111.0**
	Sub-bituminous Coal	8,130.8				10.3			**8,120.5**
	Lignite	967.8				59.2			**908.5**
	Coke		32.8	23.9	0.9				**8.0**
	Unspecified		229.0	3,265.9	166.5	490.4		41.6	**(3,652.2)**
Gas Fuels	Natural Gas	24,599.9	3,216.2	1,633.4	9.1	303.7		27.1	**25,897.1**
Liquid Fuels	Crude Oil	13,769.3	19,239.5	137.9	190.6				**32,680.3**
	Nat Gas Liquids and LRGs	3,245.8	229.1	423.7	88.0			11.4	**2,974.6**
	Other Liquids		2,679.0	456.4	108.2				**2,114.4**
	Motor Gasoline	200.7	84.3	781.1	(28.3)			242.3	**(225.6)**
	Aviation Gasoline		0.1		(0.4)				**0.6**
	Kerosene		2.6	11.3	(3.9)			7.2	**2.5**
	Jet Fuel		113.4	274.8	(10.6)		916.3	56.4	**(1,010.7)**
	Distillate Fuel		269.0	2,147.3	(83.9)	2.7	406.5	132.9	**(2,070.6)**
	Residual Oil		588.9	893.8	(1.5)	62.9	0.3	163.8	**(202.8)**
	Naphtha for petrochemical feedstocks		60.8		0.8				**60.0**
	Petroleum Coke		26.6	1,109.4	4.5	47.6			**(1,134.9)**
	Other Oil for petrochemical feedstocks		84.5		2.7	34.3			**47.5**
	Special Naphthas		23.6	93.7	0.9				**(70.9)**
	Lubricants		69.1	165.7	(1.5)			1.0	**(94.1)**
	Waxes		10.2	11.0	0.3				**(1.1)**
	Asphalt/Road Oil		74.3	74.0	16.5				**(16.2)**
	Still Gas								
	Misc. Products		0.4	8.5	(0.1)			122.5	**114.5**
Total		**62,073.5**	**27,033.3**	**11,511.8**	**458.6**	**1,011.1**	**1,323.0**	**806.2**	**75,608.6**

Note: Totals may not sum due to independent rounding.

Table A- 268: 2012 Potential CO_2 Emissions

Fuel Category	Fuel Type	Apparent Consumption (QBtu)	Carbon Coefficients (Tg Carbon/QBtu)	Potential Emissions (Tg CO_2 Eq.)
Solid Fuels	Anthracite Coal	0.05	28.28	**5.0**
	Bituminous Coal	11.11	25.44	**1,036.5**
	Sub-bituminous Coal	8.12	26.50	**789.1**
	Lignite	0.91	26.65	**88.8**
	Coke	0.01	31.00	**0.9**
	Unspecified	(3.65)	25.34	**(339.3)**
Gas Fuels	Natural Gas	25.90	14.46	**1,372.6**
Liquid Fuels	Crude Oil	32.68	20.31	**2,433.2**
	Nat Gas Liquids and LRGs	2.97	16.89	**184.2**
	Other Liquids	2.11	20.31	**157.4**
	Motor Gasoline	(0.23)	19.46	**(16.1)**
	Aviation Gasoline	0.00	18.86	**0.0**
	Kerosene	0.00	19.96	**0.2**
	Jet Fuel	(1.01)	19.70	**(73.0)**
	Distillate Fuel	(2.07)	20.17	**(153.1)**
	Residual Oil	(0.20)	20.48	**(15.2)**
	Naphtha for petrochemical feedstocks	0.06	18.55	**4.1**
	Petroleum Coke	(1.13)	27.85	**(115.9)**
	Other Oil for petrochemical feedstocks	0.05	20.17	**3.5**
	Special Naphthas	(0.07)	19.74	**(5.1)**
	Lubricants	(0.09)	20.20	**(7.0)**
	Waxes	(0.00)	19.80	**(0.1)**
	Asphalt/Road Oil	(0.02)	20.55	**(1.2)**
	Still Gas		18.20	
	Misc. Products	0.11	20.31	**8.5**
Total				**5,358.0**

Data Sources: C content coefficients by coal rank from USGS (1998) and SAIC (2004); Unspecified Solid Fuels, EIA (2014), Natural Gas and Liquid Fuels: EPA (2010).
Note: Totals may not sum due to independent rounding.

Table A-269: 2012 Non-Energy Carbon Stored in Products

Fuel Type	Consumption for Non-Energy Use (TBtu)	Carbon Coefficients (Tg Carbon/QBtu)	Carbon Content (Tg Carbon)	Fraction Sequestered	Carbon Stored (Tg CO_2 Eq.)
Coal	122.4	31.00	3.79	0.10	2.1
Natural Gas	293.2	14.46	4.24	0.70	10.9
Asphalt & Road Oil	826.7	20.55	16.99	1.00	62.0
LPG	1,903.0	17.06	32.47	0.70	83.2
Lubricants	254.8	20.20	5.15	0.09	1.7
Pentanes Plus	43.8	19.10	0.84	0.70	2.1
Petrochemical Feedstocks	[a]	[a]	[a]	[a]	40.2
Petroleum Coke	0.0	27.85	0.00	0.30	0.0
Special Naphtha	14.1	19.74	0.28	0.70	0.7
Waxes/Misc.	[a]	[a]	[a]	[a]	1.3
Misc. U.S. Territories Petroleum	[a]	[a]	[a]	[a]	0.9
Total					**205.2**

[a] Values for Misc. U.S. Territories Petroleum, Petrochemical Feedstocks and Waxes/Misc. are not shown because these categories are aggregates of numerous smaller components.

Note: Totals may not sum due to independent rounding.

Table A-270: 2012 Reference Approach CO_2 Emissions from Fossil Fuel Consumption (Tg CO_2 Eq. unless otherwise noted)

Fuel Category	Potential Emissions	Carbon Sequestered	Net Emissions	Fraction Oxidized	Total Emissions
Coal	1,581.0	2.1	1,578.9	100.0%	**1,578.9**
Petroleum	2,404.4	192.2	2,212.1	100.0%	**2,212.1**
Natural Gas	1,372.6	10.9	1,316.7	100.0%	**1,361.7**
Total	**5,358.0**	**205.2**	**5,152.8**		**5,152.8**

Note: Totals may not sum due to independent rounding.

Table A-271: Fuel Consumption in the United States by Estimating Approach (TBtu)*

Approach	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Sectoral	**69,786**	**74,929**	**77,450**	**78,465**	**78,963**	**80,161**	**82,542**	**81,118**	**81,919**	**82,339**	**84,031**	**83,995**	**82,854**	**84,206**	**81,607**	**76,891**	**79,649**	**78,227**	**76,431**
Coal	18,072	19,187	20,068	20,529	20,823	20,830	21,748	21,121	21,192	21,625	21,893	22,187	21,834	22,067	21,753	19,231	20,267	19,071	16,819
Natural Gas	19,184	22,170	22,589	22,723	22,323	22,366	23,392	22,466	23,163	22,561	22,623	22,282	21,960	23,371	23,594	23,193	24,312	24,679	25,805
Petroleum	32,530	33,573	34,793	35,213	35,817	36,965	37,402	37,531	37,564	38,152	39,515	39,526	39,060	38,768	36,260	34,467	35,070	34,477	33,806
Reference (Apparent)	**68,928**	**74,190**	**76,549**	**78,062**	**78,203**	**79,250**	**81,617**	**80,762**	**81,526**	**81,892**	**83,700**	**83,626**	**82,229**	**84,013**	**80,450**	**76,623**	**78,103**	**76,904**	**75,609**
Coal	17,573	18,567	19,425	20,105	19,981	20,030	20,957	20,710	20,797	21,081	21,735	21,986	21,534	21,577	21,391	19,243	19,582	18,914	16,544
Natural Gas	19,276	22,274	22,696	22,828	22,403	22,458	23,484	22,535	23,238	22,630	22,690	22,349	22,029	23,441	23,666	23,277	24,409	24,778	25,897
Petroleum	32,080	33,349	34,427	35,129	35,819	36,761	37,176	37,517	37,491	38,181	39,275	39,291	38,666	38,995	35,394	34,103	34,112	33,212	33,167
Difference	**-1.2%**	**-1.0%**	**-1.2%**	**-0.5%**	**-1.0%**	**-1.1%**	**-1.1%**	**-0.4%**	**-0.5%**	**-0.5%**	**-0.4%**	**-0.4%**	**-0.8%**	**-0.2%**	**-1.4%**	**-0.3%**	**-1.9%**	**-1.7%**	**-1.1%**
Coal	-2.8%	-3.2%	-3.2%	-2.1%	-4.0%	-3.8%	-3.6%	-1.9%	-1.9%	-2.5%	-0.7%	-0.9%	-1.4%	-2.2%	-1.7%	0.1%	-3.4%	-0.8%	-1.6%
Natural Gas	0.5%	0.5%	0.5%	0.5%	0.4%	0.4%	0.4%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.4%	0.4%	0.4%	0.4%
Petroleum	-1.4%	-0.7%	-1.1%	-0.2%	0.0%	-0.6%	-0.6%	0.0%	-0.2%	0.1%	-0.6%	-0.6%	-1.0%	0.6%	-2.4%	-1.1%	-2.7%	-3.7%	-1.9%

* Includes U.S. territories. Does not include international bunker fuels.

Note: Totals may not sum due to independent rounding.

Table A-272: CO_2 Emissions from Fossil Fuel Combustion by Estimating Approach (Tg CO_2 Eq.)

Approach	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Sectoral	**4,866**	**5,172**	**5,360**	**5,432**	**5,485**	**5,559**	**5,736**	**5,657**	**5,697**	**5,751**	**5,864**	**5,893**	**5,812**	**5,899**	**5,721**	**5,333**	**5,525**	**5,388**	**5,182**
Coal	1,719	1,823	1,907	1,950	1,980	1,983	2,071	2,011	2,022	2,066	2,093	2,121	2,083	2,106	2,076	1,835	1,935	1,820	1,606
Natural Gas	1,007	1,164	1,185	1,192	1,169	1,173	1,228	1,178	1,215	1,183	1,189	1,172	1,157	1,231	1,243	1,221	1,278	1,297	1,356
Petroleum	2,140	2,184	2,268	2,290	2,336	2,403	2,437	2,467	2,460	2,502	2,582	2,600	2,572	2,563	2,402	2,277	2,313	2,271	2,221
Reference (Apparent)	**4,811**	**5,149**	**5,324**	**5,440**	**5,456**	**5,516**	**5,693**	**5,662**	**5,705**	**5,752**	**5,893**	**5,903**	**5,799**	**5,900**	**5,660**	**5,348**	**5,431**	**5,320**	**5,153**
Coal	1,654	1,756	1,836	1,901	1,894	1,902	1,988	1,967	1,976	2,002	2,065	2,087	2,049	2,053	2,036	1,832	1,865	1,803	1,579
Natural Gas	1,013	1,171	1,192	1,199	1,174	1,179	1,233	1,182	1,220	1,188	1,194	1,176	1,161	1,235	1,247	1,226	1,283	1,303	1,362
Petroleum	2,144	2,222	2,296	2,340	2,388	2,435	2,472	2,513	2,509	2,562	2,634	2,640	2,589	2,613	2,377	2,290	2,283	2,214	2,212
Difference	**-1.1%**	**-0.4%**	**-0.7%**	**0.2%**	**-0.5%**	**-0.8%**	**-0.7%**	**0.1%**	**0.1%**	**0.0%**	**0.5%**	**0.2%**	**-0.2%**	**0.0%**	**-1.1%**	**0.3%**	**-1.7%**	**-1.3%**	**-0.6%**
Coal	-3.8%	-3.7%	-3.7%	-2.5%	-4.3%	-4.1%	-4.0%	-2.2%	-2.3%	-3.1%	-1.3%	-1.6%	-1.7%	-2.5%	-1.9%	-0.2%	-3.6%	-1.0%	-1.7%
Natural Gas	0.6%	0.6%	0.6%	0.6%	0.4%	0.5%	0.5%	0.3%	0.4%	0.4%	0.4%	0.3%	0.3%	0.3%	0.3%	0.4%	0.5%	0.5%	0.4%
Petroleum	0.2%	1.7%	1.2%	2.2%	2.2%	1.3%	1.4%	1.8%	2.0%	2.4%	2.0%	1.5%	0.7%	2.0%	-1.1%	0.6%	-1.3%	-2.5%	-0.4%

* Includes U.S. territories. Does not include international bunker fuels.

Note: Totals may not sum due to independent rounding.

ANNEX 5 Assessment of the Sources and Sinks of Greenhouse Gas Emissions Not Included

Although this report is intended to be a comprehensive assessment of anthropogenic[102] sources and sinks of greenhouse gas emissions for the United States, certain sources have been identified but not included in the estimates presented for various reasons. Before discussing these sources, however, it is important to note that processes or activities that are not *anthropogenic in origin* or do not result in a *net source or sink* of greenhouse gas emissions are intentionally excluded from a national inventory of anthropogenic greenhouse gas emissions, in line with guidance from the IPCC in their guidelines for national inventories.

Given a source category that is both anthropogenic and results in net greenhouse gas emissions, reasons for not including a source related to an anthropogenic activity include one or more of the following:

- Though an estimating method has been developed, data were not adequately available to calculate emissions.
- Emissions were implicitly accounted for within another source category (e.g., CO_2 from Fossil Fuel Combustion).

It is also important to note that the United States believes that the sources discussed below are very low in comparison with the overall estimate of total U.S. greenhouse gas emissions, and not including them introduces a very minor bias. In general, the emission sources described in this annex are for source categories with methodologies introduced in the 2006 IPCC Guidelines for which data collection has not been sufficient to pursue an initial estimation of greenhouse gases.

N_2O from Caprolactam Production

Caprolactam is a widely used chemical intermediate, primarily to produce nylon-6. All processes for producing caprolactam involve the catalytic oxidation of ammonia, with N_2O being produced as a byproduct. More research is required to determine this source's significance because there is currently insufficient information available on caprolactam production to estimate emissions in the United States.

CO_2 from Calcium Carbide Production

CO_2 is formed by the oxidation of petroleum coke in the production of calcium carbide. These CO_2 emissions are implicitly accounted for in the storage factor calculation for the non-energy use of petroleum coke in the Energy chapter. There is currently not sufficient data on coke consumption for calcium carbide production to estimate emissions from this source.

CO_2 from Graphite Consumption in Ferroalloy and Steel Production

Emissions from "graphite," "wood," or "biomass" in calculating CO_2 emissions from ferroalloy production, iron and steel production or other "Industrial Processes" included in Chapter 4 of the inventory are not explicitly calculated. It is assumed that 100 percent of the C used in ferroalloy production is derived from petroleum coke and that all of the C used in iron and steel production is derived from coal coke or petroleum coke. It is also assumed that all of the C used in lead and zinc production is derived from coal coke. It is possible that some non-coke C is used in the production of ferroalloys, lead, zinc, and iron and steel, but no data are available to conduct inventory calculations for sources of C other than petroleum coke and coal coke used in these processes.

Non-fuel uses of coal coke and petroleum coke are accounted for in the Industrial Process chapter, either directly for iron and steel, aluminum, ferroalloy, lead, zinc, and titanium dioxide production, or indirectly by applying a storage factor to "uncharacterized" non-fuel uses of petroleum coke and coal coke. Non-fuel uses of wood and biomass are not

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[102] The term "anthropogenic," in this context, refers to greenhouse gas emissions and removals that are a direct result of human activities or are the result of natural processes that have been affected by human activities ("2006 IPCC Guidelines for National Greenhouse Gas Inventories").

accounted for in the Energy or Industrial Process chapters, as all uses of wood and biomass are accounted for in the Land Use, Land-Use Change, and Forestry chapter. It is assumed for the purposes of the CO_2 emission calculation that no wood or other biogenic C is used in any of these industrial processes. Some biogenic C may be used in these industrial processes but sufficient data to estimate emissions are not available.

Consumption of either natural or synthetic graphite is not explicitly accounted for in the Industrial Process chapter. It is assumed that all of the C used in manufacturing C anodes for production of aluminum, ferroalloys, and electric arc furnace (EAF) steel are derived directly from petroleum coke and coal tar pitch (a coal coke byproduct), not from natural graphite or synthetic graphite sources. Some amount of C used in these industrial processes may be derived from natural or synthetic graphite sources, but sufficient data to estimate emissions are not currently available.

Miscellaneous SF_6 Uses

Sulfur hexafluoride (SF_6) is used in several applications for which estimates have not been provided in this inventory. Sulfur hexafluoride may be emitted from the production, leakage, and dismantling of radar, tracer, and night vision equipment. Emissions from this source are believed to be minor, and no data were available for estimating the emissions. Sulfur hexafluoride may be used in foam insulation, for dry etching, in laser systems, for indoor air quality testing, for laboratory hood testing, for chromatography, in tandem accelerators, in loudspeakers, in shock absorbers, and for certain biomedical applications. Emissions from this source are believed to be minor, and no data were available for estimating the emissions. Sulfur hexafluoride may be emitted from the production, breakage, or leakage of soundproof double-glazed windows. Emissions from this source are believed to be minor, and no data were available for estimating the emissions. Sulfur hexafluoride may be emitted from applications involving the production of sport shoes, tires, and tennis balls. Emissions from this source are believed to be minor, and no data were available for estimating the emissions. Sulfur hexafluoride may be emitted from applications involving tracer gasses to detect leakage from pressure vessels and as a tracer gas in the open air. Emissions from this source are believed to be minor, and no data were available for estimating the emissions.

CO_2 from Non-Hazardous Industrial Waste Incineration and Medical Waste Incineration

Waste incineration is incorporated in two sections of the energy chapter of the inventory: in the section on CO_2 emissions from waste incineration, and in the calculation of emissions and storage from non-energy uses of fossil fuels. The former section addresses fossil-derived materials (such as plastics) that are discarded as part of the municipal wastestream and combusted (generally for energy recovery). The latter addresses two types of combustion: hazardous waste incineration of organic materials (assumed to be fossil-derived), in which regulated wastes are burned without energy recovery, and burning of fossil-derived materials for energy recovery. There additional categories of waste incineration that is not included in our calculus: industrial non-hazardous waste and medical waste incineration. Data are not readily available for these sources. Further research is needed to estimate the magnitude of CO_2 emissions, though they are believed to be very low in comparison with the overall emissions of waste incineration sources that are covered.

ANNEX 6 Additional Information

6.1. Global Warming Potential Values

Global Warming Potential (GWP) is intended as a quantified measure of the globally averaged relative radiative forcing impacts of a particular greenhouse gas. It is defined as the cumulative radiative forcing—both direct and indirect effects—integrated over a period of time from the emission of a unit mass of gas relative to some reference gas (IPCC 1996). Carbon dioxide (CO_2) was chosen as this reference gas. Direct effects occur when the gas itself is a greenhouse gas. Indirect radiative forcing occurs when chemical transformations involving the original gas produce a gas or gases that are greenhouse gases, or when a gas influences other radiatively important processes such as the atmospheric lifetimes of other gases. The relationship between gigagrams (Gg) of a gas and teragrams of CO_2 equivalents (Tg CO_2 Eq.) can be expressed as follows:

$$\text{Tg CO}_2\text{ Eq.} = (\text{Gg of gas}) \times (\text{GWP}) \times \left(\frac{\text{Tg}}{1{,}000\text{ Gg}}\right)$$

where,

Tg CO_2 Eq. = Teragrams of Carbon Dioxide Equivalents
Gg = Gigagrams (equivalent to a thousand metric tons)
GWP = Global Warming Potential
Tg = Teragrams

GWP values allow policy makers to compare the impacts of emissions and reductions of different gases. According to the IPCC, GWP values typically have an uncertainty of ±35 percent, though some GWP values have larger uncertainty than others, especially those in which lifetimes have not yet been ascertained. In the following decision, the parties to the UNFCCC have agreed to use consistent GWP values from the IPCC Second Assessment Report (SAR), based upon a 100 year time horizon, although other time horizon values are available (see Table A-273).

> *In addition to communicating emissions in units of mass, Parties may choose also to use global warming potentials (GWPs) to reflect their inventories and projections in carbon dioxide-equivalent terms, using information provided by the Intergovernmental Panel on Climate Change (IPCC) in its Second Assessment Report. Any use of GWPs should be based on the effects of the greenhouse gases over a 100-year time horizon. In addition, Parties may also use other time horizons.*[103]

Greenhouse gases with relatively long atmospheric lifetimes (e.g., CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6) tend to be evenly distributed throughout the atmosphere, and consequently global average concentrations can be determined. However, the short-lived gases such as water vapor, carbon monoxide, tropospheric ozone, other indirect greenhouse gases (e.g., NO_x and NMVOCs), and tropospheric aerosols (e.g., SO_2 products and black carbon) vary spatially, and consequently it is difficult to quantify their global radiative forcing impacts. GWP values are generally not attributed to these gases that are short-lived and spatially inhomogeneous in the atmosphere.

Table A-273: Global Warming Potentials (GWP) and Atmospheric Lifetimes (Years) of Gases Used in this Report

Gas	Atmospheric Lifetime	100-year GWP[a]	20-year GWP	500-year GWP
Carbon dioxide (CO_2)	See footnote[c]	1	1	1
Methane (CH_4)[b]	12±3	21	56	6.5
Nitrous oxide (N_2O)	120	310	280	170
HFC-23	264	11,700	9,100	9,800
HFC-32	5.6	650	2,100	200

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[103] Framework Convention on Climate Change; FCCC/CP/1996/15/Add.1; 29 October 1996; Report of the Conference of the Parties at its second session; held at Geneva from 8 to 19 July 1996; Addendum; Part Two: Action taken by the Conference of the Parties at its second session; Decision 9/CP.2; Communications from Parties included in Annex I to the Convention: guidelines, schedule and process for consideration; Annex: Revised Guidelines for the Preparation of National Communications by Parties Included in Annex I to the Convention; p. 18. FCCC (1996)

HFC-125	32.6	2,800	4,600	920
HFC-134a	14.6	1,300	3,400	420
HFC-143a	48.3	3,800	5,000	1,400
HFC-152a	1.5	140	460	42
HFC-227ea	36.5	2,900	4,300	950
HFC-236fa	209	6,300	5,100	4,700
HFC-43-10mee	17.1	1,300	3,000	400
CF_4	50,000	6,500	4,400	10,000
C_2F_6	10,000	9,200	6,200	14,000
C_3F_8	2,600	7,000	4,800	10,100
C_4F_{10}	2,600	7,000	4,800	10,100
c-C_4F_8	3,200	8,700	6,000	12,700
C_5F_{12}	4,100	7,500	5,100	11,000
C_6F_{14}	3,200	7,400	5,000	10,700
SF_6	3,200	23,900	16,300	34,900

Source: IPCC (1996)

[a] GWP values used in this report are calculated over 100 year time horizon.

[b] The methane GWP includes the direct effects and those indirect effects due to the production of tropospheric ozone and stratospheric water vapor. The indirect effect due to the production of CO_2 is not included.

[c] For a given amount of carbon dioxide emitted, some fraction of the atmospheric increase in concentration is quickly absorbed by the oceans and terrestrial vegetation, some fraction of the atmospheric increase will only slowly decrease over a number of years, and a small portion of the increase will remain for many centuries or more.

Table A-274 presents direct and net (i.e., direct and indirect) GWP values for ozone-depleting substances (ODSs). Ozone-depleting substances directly absorb infrared radiation and contribute to positive radiative forcing; however, their effect as ozone-depleters also leads to a negative radiative forcing because ozone itself is a potent greenhouse gas. There is considerable uncertainty regarding this indirect effect; therefore, a range of net GWP values is provided for ozone depleting substances. The IPCC Guidelines and the UNFCCC do not include reporting instructions for estimating emissions of ODSs because their use is being phased-out under the Montreal Protocol (see note below Table A-274). The effects of these compounds on radiative forcing are not addressed in this report

Table A-274: Net 100-year Global Warming Potentials for Select Ozone Depleting Substances

Gas	Direct	Net$_{min}$	Net$_{max}$
CFC-11	4,600	(600)	3,600
CFC-12	10,600	7,300	9,900
CFC-113	6,000	2,200	5,200
HCFC-22	1,700	1,400	1,700
HCFC-123	120	20	100
HCFC-124	620	480	590
HCFC-141b	700	(5)	570
HCFC-142b	2,400	1,900	2,300
$CHCl_3$	140	(560)	0
CCl_4	1,800	(3,900)	660
CH_3Br	5	(2,600)	(500)
Halon-1211	1,300	(24,000)	(3,600)
Halon-1301	6,900	(76,000)	(9,300)

Source: IPCC (2001)

Parentheses indicate negative values.

Note: Because these compounds have been shown to deplete stratospheric ozone, they are typically referred to as ozone depleting substances (ODSs). However, they are also potent greenhouse gases. Recognizing the harmful effects of these compounds on the ozone layer, in 1987 many governments signed the Montreal Protocol on Substances that Deplete the Ozone Layer to limit the production and importation of a number of CFCs and other halogenated compounds. The United States furthered its commitment to phase-out ODSs by signing and ratifying the Copenhagen Amendments to the Montreal Protocol in 1992. Under these amendments, the United States committed to ending the production and importation of halons by 1994, and CFCs by 1996.

The IPCC has published its Fifth Assessment Report (AR5), providing the most current and comprehensive scientific assessment of climate change (IPCC 2013). Within this report, the GWP values of several gases were revised relative to the SAR, the IPCC's Third Assessment Report (TAR) (IPCC 2001), and the IPCC's Fourth Assessment Report (AR4) (IPCC 2007). Thus the GWP values used in this report have been updated three times by the IPCC; although the SAR GWP values are used throughout this report, it is informative to review the changes to the GWP values and the impact such improved understanding has on the total GWP-weighted emissions of the United States. All GWP values use CO_2 as a reference gas; a change in the radiative efficiency of CO_2 thus impacts the GWP of all other greenhouse gases. Since the SAR and TAR, the IPCC has applied an improved calculation of CO_2 radiative forcing and an improved CO_2

response function. The GWP values are drawn from IPCC/TEAP (2005) and the TAR, with updates for those cases where new laboratory or radiative transfer results have been published. Additionally, the atmospheric lifetimes of some gases have been recalculated, and updated background concentrations were used. Because the revised radiative forcing of CO_2 is about 8 percent lower than that in the TAR, Table A- 275 shows how the GWP values of the other gases relative to CO_2 tend to be larger, taking into account revisions in lifetimes. Comparisons of GWP values are based on the 100-year time horizon common to UNFCCC reporting. However, there were some instances in which other variables, such as the radiative efficiency or the chemical lifetime, were altered that resulted in further increases or decreases in particular GWP values. In addition, the values for radiative forcing and lifetimes have been calculated for a variety of halocarbons, which were not presented in the SAR. Updates in some well-mixed HFC compounds (including HFC-23, HFC-32, HFC-134a, and HFC-227ea) for AR4 result from investigation into radiative efficiencies in these compounds, with some GWP values changing by up to 40 percent; with this change, the uncertainties associated with these well-mixed HFCs are thought to be approximately 12 percent.

It should be noted that the official greenhouse gas emissions presented in this report using the SAR GWP values are the final time the SAR GWP values will be used in the U.S. inventory. The United States and other developed countries to the UNFCCC have agreed to submit annual inventories in 2015 and future years to the UNFCCC using GWP values from the IPCC AR4, which will replace the current use of SAR GWP values in their annual greenhouse gas inventories. The use of IPCC AR4 GWP values in future years will apply across the entire time series of the inventory (i.e., from 1990 to 2013 in next year’s national inventory report).

Table A- 275: Comparison of GWP values and Lifetimes Used in the SAR, TAR, AR4, and AR5

	Lifetime (years)				GWP (100 year)				Difference in GWP (relative to SAR)					
Gas	SAR	TAR	AR4	AR5[a]	SAR	TAR	AR4	AR5	TAR	TAR (%)	AR4	AR4 (%)	AR5	AR5 (%)
Carbon dioxide (CO_2)	[b]	[c]	[c]	[c]	1	1	1	1	NC	NC	NC	NC	NC	NC
Methane (CH_4)[d]	12±3	8.4/12[e]	8.7/12[e]	12.4	21	23	25	28	2	10%	4	19%	7	33%
Nitrous oxide (N_2O)	120	120/114 [e]	120/114 [e]	121	310	296	298	265	(14)	(5%)	(12)	(4%)	(45)	(15%)
Hydrofluorocarbons														
HFC-23	264	260	270	222	11,700	12,000	14,800	12,400	300	3%	3,100	26%	700	6%
HFC-32	5.6	5.0	4.9	5.2	650	550	675	677	(100)	(15%)	25	4%	27	4%
HFC-125	32.6	29	29	28.2	2,800	3,400	3,500	3,170	600	21%	700	25%	370	13%
HFC-134a	14.6	13.8	14	13.4	1,300	1,300	1,430	1,300	NC	NC	130	10%	NC	NC
HFC-143a	48.3	52	52	47.1	3,800	4,300	4,470	4,800	500	13%	670	18%	1,000	26%
HFC-152a	1.5	1.4	1.4	1.5	140	120	124	138	(20)	(14%)	(16)	(11%)	(2)	(1%)
HFC-227ea	36.5	33.0	34.2	38.9	2,900	3,500	3,220	3,350	600	21%	320	11%	450	16%
HFC-236fa	209	220	240	242	6,300	9,400	9,810	8,060	3,100	49%	3,510	56%	1,760	28%
HFC-245fa	NA	7.2	7.6	7.7	NA	950	1,030	858	NA	NA	NA	NA	NA	NA
HFC-365mfc	NA	9.9	6.6	8.7	NA	890	794	804	NA	NA	NA	NA	NA	NA
HFC-43-10mee	17.1	15	15.9	16.1	1,300	1,500	1,640	1,650	200	15%	340	26%	350	27%
Fully Fluorinated Species														
SF_6	3,200	3,200	3,200	3,200	23,900	22,200	22,800	23,500	(1,700)	(7%)	(1,100)	(5%)	(400)	(2%)
CF_4	50,000	50,000	50,000	50,000	6,500	5,700	7,390	6,630	(800)	(12%)	890	14%	130	2%
C_2F_6	10,000	10,000	10,000	10,000	9,200	11,900	12,200	11,100	2,700	29%	3,000	33%	1,900	21%
C_3F_8	2,600	2,600	2,600	2,600	7,000	8,600	8,830	8,900	1,600	23%	1,830	26%	1,900	27%
C_4F_{10}	2,600	2,600	2,600	2,600	7,000	8,600	8,860	9,200	1,600	23%	1,860	27%	2,200	31%
c-C_4F_8	3,200	3,200	3,200	3,200	8,700	10,000	10,300	9,540	1,300	15%	1,600	18%	840	10%
C_5F_{12}	4,100	4,100	4,100	4,100	7,500	8,900	9,160	8,550	1,400	19%	1,660	22%	1,050	14%
C_6F_{14}	3,200	3,200	3,200	3,100	7,400	9,000	9,300	7,910	1,600	22%	1,900	26%	510	7%
Others[f]														
NF_3	NA	740	740	500	NA	10,800	17,200	16,100	NA	NA	NA	NA	NA	NA

NC (No Change)

NA (Not Applicable)

[a] The GWP values presented here are the ones most consistent with the methodology used in the AR4 report. The AR5 report has also calculated GWP values (not shown here) where climate-carbon feedbacks have been included for the non-CO_2 gases in order to be consistent with the approach used in calculating the CO_2 lifetime. Additionally, the AR5 reported separate values for fossil versus biogenic methane in order to account for the CO_2 oxidation product.

[b] For a given amount of carbon dioxide emitted, some fraction of the atmospheric increase in concentration is quickly absorbed by the oceans and terrestrial vegetation, some fraction of the atmospheric increase will only slowly decrease over a number of years, and a small portion of the increase will remain for many centuries or more.

[c] No single lifetime can be determined for CO_2. (See IPCC 2001)

[d] The methane GWP includes the direct effects and those indirect effects due to the production of tropospheric ozone and stratospheric water vapor. The indirect effect due to the production of CO_2 is not included.

[e] Methane and nitrous oxide have chemical feedback systems that can alter the length of the atmospheric response, in these cases, global mean atmospheric lifetime (LT) is given first, followed by perturbation time (PT).

[f] Gases whose lifetime has been determined only via indirect means or for whom there is uncertainty over the loss process.

Note: Parentheses indicate negative values.

Source: IPCC (2013), IPCC (2007), IPCC (2001), IPCC (1996).

The choice of GWP values between the SAR, TAR, AR4, and AR5 has an impact on both the overall emissions estimated by the inventory, as well as the trend in emissions over time. To summarize, Table A-276 shows the overall trend in U.S. greenhouse gas emissions, by gas, from 1990 through 2012 using the four GWP sets. The table also presents the impact of TAR, AR4, and AR5 GWP values on the total emissions for 1990 and for 2012.

Table A-276: Effects on U.S. Greenhouse Gas Emissions Using SAR, TAR, AR4, and AR5 GWP values (Tg CO_2 Eq.)

Gas	Trend from 1990 to 2012				Revisions to Annual Emission Estimates (relative to SAR)					
					TAR	AR4	AR5	TAR	AR4	AR5
	SAR	TAR	AR4	AR5	1990			2012		
CO_2	274.5	274.5	274.5	274.5	NC	NC	NC	NC	NC	NC
CH_4	(68.4)	(74.9)	(81.5)	(91.2)	60.5	121.1	211.9	54.0	108.1	189.1
N_2O	11.5	11.0	11.0	9.8	(18.0)	(15.4)	(57.9)	(18.5)	(15.9)	(59.5)
HFCs, PFCs, and SF_6*	74.8	80.9	80.4	77.8	(2.2)	11.8	2.9	3.9	17.4	5.8
Total	**292.4**	**291.4**	**284.5**	**270.8**	**40.3**	**117.5**	**156.9**	**39.4**	**109.6**	**135.4**
Percent Change	**4.7%**	**4.6%**	**4.5%**	**4.2%**	**0.6%**	**1.9%**	**2.5%**	**0.6%**	**1.7%**	**2.1%**

NC (No Change)

*Includes NF_3

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

When the GWP values from the AR4 are applied to the emission estimates presented in this report, total emissions for the year 2012 are 6,635.2 Tg CO_2 Eq., as compared to 6,525.6 Tg CO_2 Eq. when the GWP values from the SAR are used (a 1.7 percent difference). Table A-277 provides a detailed summary of U.S. greenhouse gas emissions and sinks for 1990 through 2012, using the GWP values from the AR4. The percent change in emissions is equal to the percent change in the GWP; however, in cases where multiple gases are emitted in varying amounts the percent change is variable over the years, such as with substitutes for ozone depleting substances. Table A-278 summarizes the resulting change in emissions from SAR to AR4 GWP values for 1990 through 2012 including the percent change for 2012.

Table A-277: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks using the AR4 GWP values (Tg CO_2 Eq.)

Gas/Source	1990	2005	2008	2009	2010	2011	2012
CO_2	**5,108.7**	**6,112.2**	**5,936.9**	**5,506.1**	**5,722.3**	**5,592.2**	**5,383.2**
Fossil Fuel Combustion	4,745.1	5,752.9	5,593.4	5,225.7	5,404.9	5,271.1	5,072.3
Electricity Generation	1,820.8	2,402.1	2,360.9	2,146.4	2,259.2	2,158.5	2,022.7
Transportation	1,494.0	1,891.7	1,816.5	1,747.7	1,765.0	1,747.9	1,739.5
Industrial	845.1	827.6	804.1	727.5	775.6	768.7	774.2
Residential	338.3	357.9	346.2	336.4	334.8	324.9	288.9
Commercial	219.0	223.5	224.7	223.9	220.7	221.5	197.4
U.S. Territories	27.9	50.0	41.0	43.8	49.6	49.6	49.6
Non-Energy Use of Fuels	120.8	141.0	128.0	108.1	120.8	117.3	110.3
Iron and Steel Production & Metallurgical Coke Production	99.8	66.7	66.8	43.0	55.7	60.0	54.3
Natural Gas Systems	37.7	30.0	32.7	32.2	32.4	35.1	35.2
Cement Production	33.3	45.9	41.2	29.4	31.3	32.0	35.1
Lime Production	11.4	14.0	14.0	10.9	12.8	13.5	13.3
Incineration of Waste	8.0	12.5	11.9	11.7	12.0	12.1	12.2
Ammonia Production	13.0	9.2	8.4	8.5	9.2	9.4	9.4
Other Process Uses of Carbonates	4.9	6.3	5.9	7.6	9.6	9.3	8.0
Cropland Remaining Cropland	7.1	7.9	8.6	7.2	8.6	7.9	7.4
Urea Consumption for Non-Agricultural Purposes	3.8	3.7	4.1	3.4	4.7	4.0	5.2
Petrochemical Production	3.4	4.3	3.6	2.8	3.5	3.5	3.5
Aluminum Production	6.8	4.1	4.5	3.0	2.7	3.3	3.4
Soda Ash Production and Consumption	2.7	2.9	2.9	2.5	2.6	2.6	2.7
Carbon Dioxide Consumption	1.4	1.3	1.8	1.8	2.3	1.8	1.8
Titanium Dioxide Production	1.2	1.8	1.8	1.6	1.8	1.7	1.7
Ferroalloy Production	2.2	1.4	1.6	1.5	1.7	1.7	1.7
Zinc Production	0.6	1.0	1.2	0.9	1.2	1.3	1.4

Glass Production	1.5	1.9	1.5	1.0	1.5	1.3	1.2
Phosphoric Acid Production	1.6	1.4	1.2	1.0	1.1	1.2	1.1
Wetlands Remaining Wetlands	1.0	1.1	1.0	1.1	1.0	0.9	0.8
Lead Production	0.5	0.6	0.5	0.5	0.5	0.5	0.5
Petroleum Systems	0.4	0.3	0.3	0.3	0.3	0.3	0.4
Silicon Carbide Production and Consumption	0.4	0.2	0.2	0.1	0.2	0.2	0.2
Land Use, Land-Use Change, and Forestry (Sink)[a]	*(831.1)*	*(1,030.7)*	*(981.0)*	*(961.6)*	*(968.0)*	*(980.3)*	*(979.3)*
Wood Biomass and Ethanol Consumption[b]	*218.6*	*228.6*	*253.7*	*249.5*	*264.0*	*267.0*	*266.9*
International Bunker Fuels[c]	*103.5*	*113.1*	*114.3*	*106.4*	*117.0*	*111.7*	*105.8*
CH_4	**756.8**	**697.3**	**721.4**	**710.1**	**697.1**	**688.4**	**675.3**
Enteric Fermentation	164.2	169.6	175.0	173.9	172.5	170.2	167.8
Natural Gas Systems	186.2	181.0	180.5	170.2	160.3	158.6	154.6
Landfills	175.9	133.5	136.1	137.3	130.8	127.8	122.4
Coal Mining	96.5	63.8	75.6	79.9	82.3	71.2	66.5
Manure Management	37.5	56.6	61.3	60.1	61.7	62.0	63.0
Petroleum Systems	42.6	34.3	34.3	34.7	35.2	36.3	37.8
Forest Land Remaining Forest Land	3.0	9.6	10.4	6.9	5.6	16.6	18.2
Wastewater Treatment	15.7	15.9	15.9	15.6	15.5	15.3	15.2
Rice Cultivation	9.2	8.9	9.3	9.4	11.1	8.5	8.8
Stationary Combustion	8.9	7.9	7.9	7.9	7.6	7.6	6.8
Abandoned Underground Coal Mines	7.2	6.6	6.3	6.1	5.9	5.8	5.6
Petrochemical Production	2.7	3.7	3.4	3.4	3.7	3.7	3.7
Mobile Combustion	5.5	2.8	2.3	2.2	2.1	2.1	2.0
Composting	0.4	1.9	2.0	1.9	1.8	1.9	1.9
Iron and Steel Production & Metallurgical Coke Production	1.1	0.9	0.8	0.4	0.6	0.7	0.7
Field Burning of Agricultural Residues	0.3	0.2	0.3	0.3	0.3	0.3	0.3
Ferroalloy Production	+	+	+	+	+	+	+
Silicon Carbide Production and Consumption	+	+	+	+	+	+	+
Incineration of Waste	+	+	+	+	+	+	+
International Bunker Fuels[c]	*0.2*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*
N_2O	**383.2**	**399.7**	**406.9**	**396.3**	**393.5**	**401.1**	**394.2**
Agricultural Soil Management	271.2	285.8	306.7	304.1	298.1	295.8	294.7
Stationary Combustion	11.8	19.8	20.3	20.0	21.7	20.8	21.1
Manure Management	13.8	16.4	17.1	17.0	17.1	17.3	17.3
Mobile Combustion	42.3	35.5	24.5	21.8	19.9	17.8	15.9
Nitric Acid Production	17.5	16.3	16.2	13.5	16.1	15.2	14.7
Forest Land Remaining Forest Land	2.0	6.7	7.2	4.9	4.1	11.3	12.3
Adipic Acid Production	15.2	7.1	2.5	2.7	4.2	10.2	5.5
Wastewater Treatment	3.3	4.3	4.6	4.6	4.7	4.8	4.8
N_2O from Product Uses	4.2	4.2	4.2	4.2	4.2	4.2	4.2
Composting	0.3	1.7	1.8	1.7	1.6	1.7	1.7
Settlements Remaining Settlements	0.9	1.4	1.4	1.3	1.4	1.5	1.4
Incineration of Waste	0.5	0.4	0.4	0.4	0.4	0.4	0.4
Field Burning of Agricultural Residues	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wetlands Remaining Wetlands	+	+	+	+	+	+	+
International Bunker Fuels[c]	*0.9*	*1.0*	*1.0*	*0.9*	*1.0*	*1.0*	*0.9*
HFCs	**46.6**	**133.0**	**150.6**	**148.5**	**158.9**	**164.5**	**167.5**
Substitution of Ozone Depleting Substances[d]	0.3	112.8	133.1	141.5	150.6	155.5	161.9

HCFC-22 Production	46.1	20.0	17.2	6.8	8.0	8.8	5.5
Semiconductor Manufacture	0.2	0.2	0.2	0.2	0.2	0.2	0.2
PFCs	**24.3**	**7.1**	**6.6**	**4.4**	**4.9**	**7.5**	**6.9**
Semiconductor Manufacture	2.9	3.7	3.4	2.5	3.1	4.1	3.9
Aluminum Production	21.5	3.4	3.2	1.9	1.9	3.5	2.9
SF_6	**31.1**	**14.0**	**10.2**	**9.2**	**9.4**	**10.3**	**8.0**
Electrical Transmission and Distribution	25.4	10.5	8.0	7.2	6.9	6.9	5.7
Magnesium Production and Processing	5.2	2.7	1.8	1.6	2.1	2.8	1.6
Semiconductor Manufacture	0.5	0.7	0.4	0.3	0.4	0.7	0.6
Total	**6,350.7**	**7,363.3**	**7,232.7**	**6,774.6**	**6,986.1**	**6,864.0**	**6,635.2**
Net Emissions (Sources and Sinks)	**5,519.6**	**6,332.6**	**6,251.7**	**5,813.0**	**6,018.1**	**5,883.7**	**5,655.9**

+ Does not exceed 0.05 Tg CO_2 Eq.

[a] The net CO_2 flux total includes both emissions and sequestration, and constitutes a sink in the United States. Parentheses indicate negative values or sequestration.

[b] Emissions from Wood Biomass and Ethanol Consumption are not included specifically in summing energy sector totals.

[c] Emissions from International Bunker Fuels are not included in totals.

[d] Small amounts of PFC emissions also result from this source.

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

Table A-278: Change in U.S. Greenhouse Gas Emissions and Sinks Using SAR vs. AR4 GWP values (Tg CO_2 Eq.)

Gas/Source	1990	2005	2008	2009	2010	2011	2012	Percent Change in 2012
CO_2	**NC**	**NC**	**NC**	**NC**	**NC**	**NC**	**NC**	**NC**
CH_4	**121.1**	**111.6**	**115.4**	**113.6**	**111.5**	**110.2**	**108.1**	**19%**
Enteric Fermentation	26.3	27.1	28.0	27.8	27.6	27.2	26.9	19%
Natural Gas Systems	29.8	29.0	28.9	27.2	25.7	25.4	24.7	19%
Landfills	28.1	21.4	21.8	22.0	20.9	20.4	19.6	19%
Coal Mining	15.4	10.2	12.1	12.8	13.2	11.4	10.6	19%
Manure Management	6.0	9.1	9.8	9.6	9.9	9.9	10.1	19%
Petroleum Systems	6.8	5.5	5.5	5.6	5.6	5.8	6.0	19%
Forest Land Remaining Forest Land	0.5	1.5	1.7	1.1	0.9	2.7	2.9	19%
Wastewater Treatment	2.5	2.5	2.5	2.5	2.5	2.4	2.4	19%
Rice Cultivation	1.5	1.4	1.5	1.5	1.8	1.4	1.4	19%
Stationary Combustion	1.4	1.3	1.3	1.3	1.2	1.2	1.1	19%
Abandoned Underground Coal Mines	1.2	1.1	1.0	1.0	0.9	0.9	0.9	19%
Petrochemical Production	0.4	0.6	0.5	0.6	0.6	0.6	0.6	19%
Mobile Combustion	0.9	0.5	0.4	0.3	0.3	0.3	0.3	19%
Composting	0.1	0.3	0.3	0.3	0.3	0.3	0.3	19%
Iron and Steel Production & Metallurgical Coke Production	0.2	0.1	0.1	0.1	0.1	0.1	0.1	19%
Field Burning of Agricultural Residues	0.1	+	0.1	+	+	+	+	19%
Ferroalloy Production	+	+	+	+	+	+	+	19%
Silicon Carbide Production and Consumption	+	+	+	+	+	+	+	19%
Incineration of Waste	+	+	+	+	+	+	+	19%
International Bunker Fuels[a]	+	+	+	+	+	+	+	*19%*
N_2O	**(15.4)**	**(16.1)**	**(16.4)**	**(16.0)**	**(15.8)**	**(16.1)**	**(15.9)**	**(4%)**
Agricultural Soil Management	(10.9)	(11.5)	(12.4)	(12.2)	(12.0)	(11.9)	(11.9)	(4%)
Stationary Combustion	(0.5)	(0.8)	(0.8)	(0.8)	(0.9)	(0.8)	(0.9)	(4%)
Manure Management	(0.6)	(0.7)	(0.7)	(0.7)	(0.7)	(0.7)	(0.7)	(4%)
Mobile Combustion	(1.7)	(1.4)	(1.0)	(0.9)	(0.8)	(0.7)	(0.6)	(4%)
Nitric Acid Production	(0.7)	(0.7)	(0.7)	(0.5)	(0.6)	(0.6)	(0.6)	(4%)

Forest Land Remaining Forest Land	(0.1)	(0.3)	(0.3)	(0.2)	(0.2)	(0.5)	(0.5)	(4%)
Adipic Acid Production	(0.6)	(0.3)	(0.1)	(0.1)	(0.2)	(0.4)	(0.2)	(4%)
Wastewater Treatment	(0.1)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(4%)
N_2O from Product Uses	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(4%)
Composting	(0.0)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(4%)
Settlements Remaining Settlements	(0.0)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(4%)
Incineration of Waste	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(4%)
Field Burning of Agricultural Residues	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(+)	(4%)
Wetlands Remaining Wetlands	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(+)	(4%)
International Bunker Fuels[a]	*(0.0)*	*(0.0)*	*(0.0)*	*(0.0)*	*(0.0)*	*(0.0)*	*(+)*	*(4%)*
HFCs	**9.7**	**13.2**	**14.6**	**13.3**	**14.9**	**15.9**	**16.3**	**11%**
Substitution of Ozone Depleting Substances	(+)	9.0	10.9	11.9	13.2	14.0	15.1	10%
HCFC-22 Production	9.7	4.2	3.6	1.4	1.7	1.8	1.1	26%
Semiconductor Manufacture	0.045	0.0	0.0	0.0	0.0	0.0	0.0	26%
PFCs	**3.7**	**1.6**	**1.5**	**1.1**	**1.2**	**1.6**	**1.5**	**27%**
Semiconductor Manufacture	0.6	1.1	1.0	0.9	0.9	1.1	1.0	36%
Aluminum Production	3.0	0.5	0.5	0.3	0.3	0.5	0.4	18%
SF_6	**(1.5)**	**(0.7)**	**(0.5)**	**(0.4)**	**(0.5)**	**(0.5)**	**(0.4)**	**(5%)**
Electrical Transmission and Distribution	(1.2)	(0.5)	(0.4)	(0.3)	(0.3)	(0.3)	(0.3)	(5%)
Magnesium Production and Processing	(0.3)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(5%)
Semiconductor Manufacture	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(5%)
Total	**117.5**	**109.6**	**114.6**	**111.7**	**111.3**	**111.0**	**109.6**	**1.7%**

NC (No change)

+ Does not exceed 0.05 Tg CO_2 Eq.

[a] Emissions from International Bunker Fuels are not included in totals.

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

Table A-279 below shows a comparison of total emissions estimates by sector using both the IPCC SAR and AR4 GWP values. For most sectors, the change in emissions was minimal. The effect on emissions from waste was by far the greatest (17.8 percent in 2012), due the predominance of CH_4 emissions in this sector. Emissions from all other sectors were comprised of mainly CO_2 or a mix of gases, which moderated the effect of the changes.

Table A-279: Comparison of Emissions by Sector using IPCC SAR and AR4 GWP Values (Tg CO_2 Eq.)

Sector	1990	2005	2008	2009	2010	2011	2012
Energy							
SAR GWP, Used In Inventory	5,260.1	6,243.5	6,071.1	5,674.6	5,860.6	5,712.9	5,498.9
AR4 GWP, Updated	5,313.4	6,288.7	6,118.4	5,721.1	5,905.8	5,756.4	5,541.1
Difference (%)	1.0%	0.7%	0.8%	0.8%	0.8%	0.8%	0.8%
Industrial Processes							
SAR GWP, Used In Inventory	316.1	334.9	335.9	287.8	324.6	342.9	334.4
AR4 GWP, Updated	327.2	348.8	351.4	301.8	340.1	359.6	351.6
Difference (%)	3.5%	4.1%	4.6%	4.9%	4.8%	4.9%	5.2%
Solvent and Other Product Use							
SAR GWP, Used In Inventory	4.4	4.4	4.4	4.4	4.4	4.4	4.4
AR4 GWP, Updated	4.2	4.2	4.2	4.2	4.2	4.2	4.2
Difference (%)	(3.9%)	(3.9%)	(3.9%)	(3.9%)	(3.9%)	(3.9%)	(3.9%)
Agriculture							
SAR GWP, Used In Inventory	473.9	512.2	543.4	538.9	534.2	528.3	526.3
AR4 GWP, Updated	496.2	537.7	569.7	565.0	560.7	554.2	552.1
Difference (%)	4.7%	5.0%	4.8%	4.8%	5.0%	4.9%	4.9%
LULUCF							
SAR GWP, Used In Inventory	(817.4)	(1,005.2)	(953.7)	(941.1)	(948.0)	(944.3)	(941.5)
AR4 GWP, Updated	(817.0)	(1,004.0)	(952.4)	(940.2)	(947.3)	(942.2)	(939.2)

Difference (%)	0.0%	(0.1%)	(0.1%)	(0.1%)	(0.1%)	(0.2%)	(0.3%)
Waste							
SAR GWP, Used In Inventory	165.0	133.2	136.0	136.5	131.1	128.5	124.0
AR4 GWP, Updated	195.6	157.2	160.3	161.0	154.5	151.4	146.0
Difference (%)	18.5%	18.0%	17.9%	17.9%	17.9%	17.8%	17.8%
Net Emissions (Sources and Sinks)							
SAR GWP (Used in Inventory)	**5,402.1**	**6,223.1**	**6,137.1**	**5,701.2**	**5,906.7**	**5,772.7**	**5,546.3**
AR4 GWP	**5,519.6**	**6,332.6**	**6,251.7**	**5,813.0**	**6,018.1**	**5,883.7**	**5,655.9**
Difference (%)	**2.2%**	**1.8%**	**1.9%**	**2.0%**	**1.9%**	**1.9%**	**2.0%**

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

Overall, these revisions to GWP values do not have a significant effect on U.S. emission trends, as shown in Table A-280 and Table A-281.

Table A-280: Change in U.S. Greenhouse Gas Emissions and Sinks Using AR5 vs. AR4 GWP values (Tg CO_2 Eq.)

Gas	1990	2005	2008	2009	2010	2011	2012
CO_2	NC	NC	NC	NC	NC	NC	NC
CH_4	90.8	83.7	86.6	85.2	83.6	82.6	81.0
N_2O	(42.4)	(44.3)	(45.1)	(43.9)	(43.6)	(44.4)	(43.7)
HFCs	(7.5)	(11.4)	(12.3)	(11.0)	(11.6)	(11.7)	(11.2)
PFCs*	(2.4)	(0.7)	(0.6)	(0.4)	(0.5)	(0.7)	(0.6)
SF_6	1.0	0.4	0.3	0.3	0.3	0.3	0.2
Total	**39.4**	**27.7**	**28.9**	**30.2**	**28.3**	**26.2**	**25.8**

NC (No change)

*Includes NF_3

Note: Totals may not sum due to independent rounding.

Table A-281: Change in U.S. Greenhouse Gas Emissions Using AR5 vs. AR4 GWP values (Percent)

Gas/Source	1990	2005	2008	2009	2010	2011	2012
CO_2	**NC**	**NC**	**NC**	**NC**	**NC**	**NC**	**NC**
CH_4	**12.0%**	**12.0%**	**12.0%**	**12.0%**	**12.0%**	**12.0%**	**12.0%**
N_2O	**(11.1%)**	**(11.1%)**	**(11.1%)**	**(11.1%)**	**(11.1%)**	**(11.1%)**	**(11.1%)**
HFCs	**(16.0%)**	**(8.6%)**	**(8.2%)**	**(7.4%)**	**(7.3%)**	**(7.1%)**	**(6.7%)**
Substitution of Ozone Depleting Substances	11.3%	(7.2%)	(7.1%)	(7.0%)	(6.8%)	(6.6%)	(6.4%)
HCFC-22 Production[b]	(16.2%)	(16.2%)	(16.2%)	(16.2%)	(16.2%)	(16.2%)	(16.2%)
Semiconductor Manufacture[c]	(16.2%)	(16.2%)	(16.2%)	(16.2%)	(16.2%)	(16.2%)	(16.2%)
PFCs	**(10.0%)**	**(9.4%)**	**(9.3%)**	**(9.2%)**	**(9.2%)**	**(9.3%)**	**(9.4%)**
Semiconductor Manufacture[c]	(9.3%)	(8.8%)	(8.6%)	(8.6%)	(8.7%)	(8.8%)	(8.9%)
Aluminum Production[a]	(10.1%)	(10.1%)	(10.0%)	(10.0%)	(10.0%)	(10.0%)	(10.0%)
SF_6	**3.1%**	**3.1%**	**3.1%**	**3.1%**	**3.1%**	**3.1%**	**3.1%**
Total	**0.6%**	**0.4%**	**0.4%**	**0.4%**	**0.4%**	**0.4%**	**0.4%**

NC (No change)

[a] PFC emissions from CF_4 and C_2F_6

[b] HFC-23 emitted

[c] Emissions from HFC-23, CF_4, C_2F_6, C_3F_8, SF_6, and the addition of NF_3

Note: Excludes Sinks.

6.2. Ozone Depleting Substance Emissions

Ozone is present in both the stratosphere,[104] where it shields the earth from harmful levels of ultraviolet radiation, and at lower concentrations in the troposphere,[105] where it is the main component of anthropogenic photochemical "smog." Chlorofluorocarbons (CFCs), halons, carbon tetrachloride, methyl chloroform, and hydrochlorofluorocarbons (HCFCs), along with certain other chlorine and bromine containing compounds, have been found to deplete the ozone levels in the stratosphere. These compounds are commonly referred to as ozone depleting substances (ODSs). If left unchecked, stratospheric ozone depletion could result in a dangerous increase of ultraviolet radiation reaching the earth's surface. In 1987, nations around the world signed the *Montreal Protocol on Substances that Deplete the Ozone Layer*. This landmark agreement created an international framework for limiting, and ultimately eliminating, the production of most ozone depleting substances. ODSs have historically been used in a variety of industrial applications, including refrigeration and air conditioning, foam blowing, fire extinguishing, sterilization, solvent cleaning, and as an aerosol propellant.

In the United States, the Clean Air Act Amendments of 1990 provide the legal instrument for implementation of the *Montreal Protocol* controls. The Clean Air Act classifies ozone depleting substances as either Class I or Class II, depending upon the ozone depletion potential (ODP) of the compound.[106] The production of CFCs, halons, carbon tetrachloride, and methyl chloroform─all Class I substances─has already ended in the United States. However, large amounts of these chemicals remain in existing equipment,[107] and stockpiles of the ODSs, as well as material recovered from equipment being decommissioned, are used for maintaining the existing equipment. As a result, emissions of Class I compounds will continue, albeit in ever decreasing amounts, for many more years. Class II designated substances, all of which are HCFCs, have been, or are being, phased out at later dates than Class I compounds because they have lower ozone depletion potentials. These compounds served, and in some cases continue to serve, as interim replacements for Class I compounds in many industrial applications. The use and emissions of HCFCs in the United States is anticipated to continue for several decades as equipment that use Class I substances and Class II substances are retired from use. Under current controls, however, the production for domestic use of all HCFCs in the United States will end by the year 2030.

In addition to contributing to ozone depletion, CFCs, halons, carbon tetrachloride, methyl chloroform, and HCFCs are also potent greenhouse gases. However, the depletion of the ozone layer has a cooling effect on the climate that counteracts the direct warming from tropospheric emissions of ODSs. Stratospheric ozone influences the earth's radiative balance by absorption and emission of longwave radiation from the troposphere as well as absorption of shortwave radiation from the sun; overall, stratospheric ozone has a warming effect.

The IPCC has prepared both direct GWP values and net (combined direct warming and indirect cooling) GWP ranges for some of the most common ozone depleting substances (IPCC 1996). See Annex 6.1, Global Warming Potential Values, for a listing of the net GWP values for ODS.

Although the IPCC emission inventory guidelines do not require the reporting of emissions of ozone depleting substances, the United States believes that no inventory is complete without the inclusion of these compounds. Emission estimates for several ozone depleting substances are provided in Table A- 282.

Table A- 282: Emissions of Ozone Depleting Substances (Gg)

Compound	1990	2005	2008	2009	2010	2011	2012
Class I							

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[104] The stratosphere is the layer from the top of the troposphere up to about 50 kilometers. Approximately 90 percent of atmospheric ozone is within the stratosphere. The greatest concentration of ozone occurs in the middle of the stratosphere, in a region commonly called the ozone layer.

[105] The troposphere is the layer from the ground up to about 11 kilometers near the poles and 16 kilometers in equatorial regions (i.e., the lowest layer of the atmosphere, where humans live). It contains roughly 80 percent of the mass of all gases in the atmosphere and is the site for weather processes including most of the water vapor and clouds.

[106] Substances with an ozone depletion potential of 0.2 or greater are designated as Class I. All other designated substances that deplete stratospheric ozone but which have an ODP of less than 0.2 are Class II.

[107] Older refrigeration and air-conditioning equipment, fire extinguishing systems, meter-dose inhalers, and foam products blown with CFCs/HCFCs may still contain ODS.

CFC-11	29	12	10	9	8	8	8
CFC-12	126	24	10	6	4	3	3
CFC-113	59	+	+	+	+	+	+
CFC-114	5	+	+	+	+	+	+
CFC-115	9	2	1	+	+	+	+
Carbon Tetrachloride	4	+	+	+	+	+	+
Methyl Chloroform	223	+	+	+	+	+	+
Halon-1211	2	1	1	1	1	1	1
Halon-1301	2	1	1	1	1	1	1
Class II							
HCFC-22	49	82	87	88	84	83	78
HCFC-123	+	1	1	1	1	1	1
HCFC-124	+	2	2	2	1	1	1
HCFC-141b	1	4	7	8	9	9	9
HCFC-142b	2	3	4	2	1	1	1
HCFC-225ca/cb	+	+	+	+	+	+	+

+ Does not exceed 0.5 Gg.

Methodology and Data Sources

Emissions of ozone depleting substances were estimated using the EPA's Vintaging Model. 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. Please see Annex 3.8, Methodology for Estimating HFC and PFC Emissions from Substitution of Ozone Depleting Substances, of this Inventory for a more detailed discussion of the Vintaging Model.

Uncertainties

Uncertainties exist with regard to the levels of chemical production, equipment sales, equipment characteristics, and end-use emissions profiles that are used by these models. Please see the ODS Substitutes section of this report for a more detailed description of the uncertainties that exist in the Vintaging Model.

6.3. Sulfur Dioxide Emissions

Sulfur dioxide (SO_2), emitted into the atmosphere through natural and anthropogenic processes, affects the Earth's radiative budget through photochemical transformation into sulfate aerosols that can (1) scatter sunlight back to space, thereby reducing the radiation reaching the Earth's surface; (2) affect cloud formation; and (3) affect atmospheric chemical composition (e.g., stratospheric ozone, by providing surfaces for heterogeneous chemical reactions). The overall effect of SO_2-derived aerosols on radiative forcing is believed to be negative (IPCC 2007). However, because SO_2 is short-lived and unevenly distributed through the atmosphere, its radiative forcing impacts are highly uncertain. Sulfur dioxide emissions have been provided below in Table A-283.

The major source of SO_2 emissions in the United States is the burning of sulfur containing fuels, mainly coal. Metal smelting and other industrial processes also release significant quantities of SO_2. The largest contributor to U.S. emissions of SO_2 is electricity generation, accounting for 63.3 percent of total SO_2 emissions in 2012 (see Table A-284); coal combustion accounted for approximately 92.0 percent of that total. The second largest source was industrial fuel combustion, which produced 14.6 percent of 2012 SO_2 emissions. Overall, SO_2 emissions in the United States decreased by 77.4 percent from 1990 to 2012. The majority of this decline came from reductions from electricity generation, primarily due to increased consumption of low sulfur coal from surface mines in western states.

Sulfur dioxide is important for reasons other than its effect on radiative forcing. It is a major contributor to the formation of urban smog and acid rain. As a contributor to urban smog, high concentrations of SO_2 can cause significant increases in acute and chronic respiratory diseases. In addition, once SO_2 is emitted, it is chemically transformed in the atmosphere and returns to earth as the primary contributor to acid deposition, or acid rain. Acid rain has been found to accelerate the decay of building materials and paints, and to cause the acidification of lakes and streams and damage trees. As a result of these harmful effects, the United States has regulated the emissions of SO_2 under the Clean Air Act. The EPA has also developed a strategy to control these emissions via four programs: (1) the National Ambient Air Quality Standards program,[108] (2) New Source Performance Standards,[109] (3) the New Source Review/Prevention of Significant Deterioration Program,[110] and (4) the sulfur dioxide allowance program.[111]

Table A-283: SO_2 Emissions (Gg)

Sector/Source	1990	2005	2008	2009	2010	2011	2012
Energy	**19,628**	**12,350**	**8,659**	**7,579**	**6,406**	**5,277**	**4,118**
Stationary Combustion	18,407	11,529	8,289	7,208	6,128	5,048	3,895
Oil and Gas Activities	390	180	135	125	115	105	105
Mobile Sources	793	616	217	228	147	109	103
Waste Combustion	38	25	18	17	16	14	14
Industrial Processes	**1,307**	**829**	**690**	**656**	**622**	**621**	**621**
Other Industrial Processes	362	327	229	209	189	168	168
Metals Processing	659	158	161	151	141	131	131
Chemical Manufacturing	269	227	168	150	132	114	114
Storage and Transport	6	2	6	6	7	8	8
Miscellaneous*	11	114	126	140	153	199	199
Solvent Use	**+**	**+**	**1**	**1**	**+**	**+**	**+**
Degreasing	+	0	0	0	0	0	0
Graphic Arts	+	0	0	0	0	0	0
Dry Cleaning	+	0	0	0	0	0	0
Surface Coating	NA	0	0	0	0	0	0
Other Industrial	+	+	1	1	+	+	+
Non-industrial	NA	NA	NA	NA	NA	NA	NA
Agriculture	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**
Agricultural Burning	NA	NA	NA	NA	NA	NA	NA
Waste	**+**	**1**	**1**	**1**	**+**	**+**	**+**
Landfills	+	1	1	1	+	+	+
Wastewater Treatment	+	0	0	0	0	0	0
Miscellaneous Waste	+	0	0	0	0	0	0
Total	**20,935**	**13,180**	**9,350**	**8,236**	**7,029**	**5,898**	**4,739**

Source: Data taken from EPA (2013) and disaggregated based on EPA (2003).
* Miscellaneous includes other combustion and fugitive dust categories.
+ Does not exceed 0.5 Gg
NA (Not Available)
Note: Totals may not sum due to independent rounding.

Table A-284: SO_2 Emissions from Electricity Generation (Gg)

Fuel Type	1990	2005	2008	2009	2010	2011	2012
Coal	13,808	8,680	6,488	5,599	4,709	3,820	2,760
Petroleum	580	458	342	295	248	201	146
Natural Gas	1	174	130	112	94	76	55
Misc. Internal Combustion	45	57	43	37	31	25	18
Other	NA	71	53	46	38	31	22
Total	**14,433**	**9,439**	**7,055**	**6,088**	**5,121**	**4,154**	**3,001**

Source: Data taken from EPA (2013) and disaggregated based on EPA (2003).
Note: Totals may not sum due to independent rounding.

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[108] [42 U.S.C § 7409, CAA § 109]

[109] [42 U.S.C § 7411, CAA § 111]

[110] [42 U.S.C § 7473, CAA § 163]

[111] [42 U.S.C § 7651, CAA § 401]

6.4. Complete List of Source Categories

Chapter/Source	Gas(es)
Energy	
Fossil Fuel Combustion	CO_2
Non-Energy Use of Fossil Fuels	CO_2
Stationary Combustion (excluding CO_2)	CH_4, N_2O, CO, NO_x, NMVOC
Mobile Combustion (excluding CO_2)	CH_4, N_2O, CO, NO_x, NMVOC
Coal Mining	CH_4
Abandoned Underground Coal Mines	CH_4
Natural Gas Systems	CH_4
Petroleum Systems	CH_4
Incineration of Waste	CO_2, CH_4, N_2O
Industrial Processes	
Titanium Dioxide Production	CO_2
Aluminum Production	CO_2, CF_4, C_2F_6
Iron and Steel Production	CO_2, CH_4
Ferroalloy Production	CO_2, CH_4
Ammonia Production	CO_2
Urea Consumption for Non-Agricultural Purposes	CO_2
Cement Production	CO_2
Lime Production	CO_2
Other Process Uses of Carbonates	CO_2
Soda Ash Production and Consumption	CO_2
Glass Production	CO_2
Carbon Dioxide Consumption	CO_2
Phosphoric Acid Production	CO_2
Petrochemical Production	CH_4, CO_2
Silicon Carbide Production and Consumption	CH_4, CO_2
Lead Production	CO_2
Zinc Production	CO_2
Adipic Acid Production	N_2O
Nitric Acid Production	N_2O
Substitution of Ozone Depleting Substances	HFCs, PFCs[a]
HCFC-22 Production	HFC-23
Semiconductor Manufacture	HFCs, PFCs, SF_6[b]
Electrical Transmission and Distributing	SF_6
Magnesium Production and Processing	SF_6
Solvent and Other Product Use	CO, NO_x, NMVOC
N_2O Product Usage	N_2O
Agriculture	
Enteric Fermentation	CH_4
Manure Management	CH_4, N_2O
Rice Cultivation	CH_4
Field Burning of Agricultural Residues	CH_4, N_2O
Agricultural Soil Management	N_2O, CO, NO_x
Land Use, Land-Use Change, and Forestry	
CO_2 Flux	CO_2 (sink)
Cropland Remaining Cropland	CO_2
Settlements Remaining Settlements	N_2O
Forestland Remaining Forestland	CH_4, N_2O
Wetlands Remaining Wetlands	CO_2, N_2O
Waste	
Landfills	CH_4
Wastewater Treatment	CH_4, N_2O
Composting	CH_4, N_2O

[a] Includes HFC-23, HFC-32, HFC-125, HFC-134a, HFC-143a, HFC-236fa, CF_4, HFC-152a, HFC-227ea, HFC-245fa, HFC-4310mee, and PFC/PFPEs.

[b] Includes such gases as HFC-23, CF_4, C_2F_6, SF_6.

6.5. Constants, Units, and Conversions

Metric Prefixes

Although most activity data for the United States is gathered in customary U.S. units, these units are converted into metric units per international reporting guidelines. Table A- 285 provides a guide for determining the magnitude of metric units.

Table A- 285: Guide to Metric Unit Prefixes

Prefix/Symbol	Factor
atto (a)	10^{-18}
femto (f)	10^{-15}
pico (p)	10^{-12}
nano (n)	10^{-9}
micro (µ)	10^{-6}
milli (m)	10^{-3}
centi (c)	10^{-2}
deci (d)	10^{-1}
deca (da)	10
hecto (h)	10^{2}
kilo (k)	10^{3}
mega (M)	10^{6}
giga (G)	10^{9}
tera (T)	10^{12}
peta (P)	10^{15}
exa (E)	10^{18}

Unit Conversions

1 kilogram = 2.205 pounds
1 pound = 0.454 kilograms
1 short ton = 2,000 pounds = 0.9072 metric tons
1 metric ton = 1,000 kilograms = 1.1023 short tons

1 cubic meter = 35.315 cubic feet
1 cubic foot = 0.02832 cubic meters
1 U.S. gallon = 3.785412 liters
1 barrel (bbl) = 0.159 cubic meters
1 barrel (bbl) = 42 U.S. gallons
1 liter = 0.001 cubic meters

1 foot = 0.3048 meters
1 meter = 3.28 feet
1 mile = 1.609 kilometers
1 kilometer = 0.622 miles

1 acre = 43,560 square feet = 0.4047 hectares = 4,047 square meters
1 square mile = 2.589988 square kilometers

To convert degrees Fahrenheit to degrees Celsius, subtract 32 and multiply by 5/9

To convert degrees Celsius to Kelvin, add 273.15 to the number of Celsius degrees

Density Conversions[112]

Methane	1 cubic meter	=	0.67606 kilograms
Carbon dioxide	1 cubic meter	=	1.85387 kilograms

Natural gas liquids	1 metric ton	=	11.6 barrels	=	1,844.2 liters
Unfinished oils	1 metric ton	=	7.46 barrels	=	1,186.04 liters
Alcohol	1 metric ton	=	7.94 barrels	=	1,262.36 liters
Liquefied petroleum gas	1 metric ton	=	11.6 barrels	=	1,844.2 liters
Aviation gasoline	1 metric ton	=	8.9 barrels	=	1,415.0 liters
Naphtha jet fuel	1 metric ton	=	8.27 barrels	=	1,314.82 liters
Kerosene jet fuel	1 metric ton	=	7.93 barrels	=	1,260.72 liters
Motor gasoline	1 metric ton	=	8.53 barrels	=	1,356.16 liters
Kerosene	1 metric ton	=	7.73 barrels	=	1,228.97 liters
Naphtha	1 metric ton	=	8.22 barrels	=	1,306.87 liters
Distillate	1 metric ton	=	7.46 barrels	=	1,186.04 liters
Residual oil	1 metric ton	=	6.66 barrels	=	1,058.85 liters
Lubricants	1 metric ton	=	7.06 barrels	=	1,122.45 liters
Bitumen	1 metric ton	=	6.06 barrels	=	963.46 liters
Waxes	1 metric ton	=	7.87 barrels	=	1,251.23 liters
Petroleum coke	1 metric ton	=	5.51 barrels	=	876.02 liters
Petrochemical feedstocks	1 metric ton	=	7.46 barrels	=	1,186.04 liters
Special naphtha	1 metric ton	=	8.53 barrels	=	1,356.16 liters
Miscellaneous products	1 metric ton	=	8.00 barrels	=	1,271.90 liters

Energy Conversions

Converting Various Energy Units to Joules

The common energy unit used in international reports of greenhouse gas emissions is the joule. A joule is the energy required to push with a force of one Newton for one meter. A terajoule (TJ) is one trillion (10^{12}) joules. A British thermal unit (Btu, the customary U.S. energy unit) is the quantity of heat required to raise the temperature of one pound of water one degree Fahrenheit at or near 39.2 Fahrenheit.

1 TJ =	2.388×10^{11} calories 23.88 metric tons of crude oil equivalent 947.8 million Btus 277,800 kilowatt-hours

Converting Various Physical Units to Energy Units

Data on the production and consumption of fuels are first gathered in physical units. These units must be converted to their energy equivalents. The conversion factors in Table A-286 can be used as default factors, if local data are not available. See Appendix A of EIA's *Annual Energy Review 2009* (EIA 2010) for more detailed information on the energy content of various fuels.

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[112] Reference: EIA (2007)

Table A-286: Conversion Factors to Energy Units (Heat Equivalents)

Fuel Type (Units)	Factor
Solid Fuels (Million Btu/Short ton)	
Anthracite coal	22.573
Bituminous coal	23.89
Sub-bituminous coal	17.14
Lignite	12.866
Coke	24.8
Natural Gas (Btu/Cubic foot)	**1,026**
Liquid Fuels (Million Btu/Barrel)	
Motor gasoline	5,218
Aviation gasoline	5.048
Kerosene	5.670
Jet fuel, kerosene-type	5.670
Distillate fuel	5.825
Residual oil	6.287
Naphtha for petrochemicals	5.248
Petroleum coke	6.024
Other oil for petrochemicals	5.825
Special naphthas	5.248
Lubricants	6.065
Waxes	5.537
Asphalt	6.636
Still gas	6.000
Misc. products	5.796

Note: For petroleum and natural gas, *Annual Energy Review 2009* (EIA 2010). For coal ranks, *State Energy Data Report 1992* (EIA 1993). All values are given in higher heating values (gross calorific values).

6.6. Abbreviations

AAPFCO	American Association of Plant Food Control Officials
ABS	Acrylonitrile butadiene styrene
ACC	American Chemistry Council
AEDT	U.S. FAA Aviation Environmental Design Tool
AFEAS	Alternative Fluorocarbon Environmental Acceptability Study
AFV	Alternative fuel vehicle
AGA	American Gas Association
AHEF	Atmospheric and Health Effect Framework
AISI	American Iron and Steel Institute
ANGA	American Natural Gas Alliance
ANL	Argonne National Laboratory
APC	American Plastics Council
API	American Petroleum Institute
APTA	American Public Transportation Association
AR4	IPCC Fourth Assessment Report
AR5	IPCC Fifth Assessment Report
ARI	Advanced Resources International
ASAE	American Society of Agricultural Engineers
ASTM	American Society for Testing and Materials
BCEF	Biomass conversion and expansion factors
BEA	Bureau of Economic Analysis, U.S. Department of Commerce
BLM	Bureau of Land Management
BoC	Bureau of Census
BOD	Biological oxygen demand
BOD5	Biochemical oxygen demand over a 5-day period
BOEMRE	Bureau of Ocean Energy Management, Regulation and Enforcement
BOF	Basic oxygen furnace

BRS	Biennial Reporting System
BTS	Bureau of Transportation Statistics, U.S. Department of Transportation
Btu	British thermal unit
C	Carbon
C&EN	Chemical and Engineering News
CAAA	Clean Air Act Amendments of 1990
CAPP	Canadian Association of Petroleum Producers
CARB	California Air Resources Board
CBI	Confidential business information
CEFM	Cattle Enteric Fermentation Model
CFC	Chlorofluorocarbon
CFR	Code of Federal Regulations
CGA	Compressed Gas Association
CH_4	Methane
CHP	Combined heat and power
CIGRE	International Council on Large Electric Systems
CKD	Cement kiln dust
CLE	Crown Light Exposure
CMA	Chemical Manufacturer's Association
CMOP	Coalbed Methane Outreach Program
CMR	Chemical Market Reporter
CNG	Compressed natural gas
CO_2	Carbon dioxide
COD	Chemical oxygen demand
COGCC	Colorado Oil and Gas Conservation Commission
CRF	Common Reporting Format
CRM	Component ratio method
CRP	Conservation Reserve Program
CTIC	Conservation Technology Information Center
CVD	Chemical vapor deposition
CWNS	Clean Watershed Needs Survey
d.b.h	Diameter breast height
DE	Digestible energy
DESC	Defense Energy Support Center-DoD's defense logistics agency
DFAMS	Defense Fuels Automated Management System
DHS	Department of Homeland Security
DM	Dry matter
DOC	Degradable organic carbon
DOC	U.S. Department of Commerce
DoD	U.S. Department of Defense
DOE	U.S. Department of Energy
DOI	U.S. Department of the Interior
DOT	U.S. Department of Transportation
DRI	Direct Reduced Iron
EAF	Electric arc furnace
EDF	Environmental Defense Fund
EF	Emission factor
EFMA	European Fertilizer Manufacturers Association
EJ	Exajoule
EGR	Exhaust gas recirculation
EIA	Energy Information Administration, U.S. Department of Energy
EIIP	Emissions Inventory Improvement Program
EOR	Enhanced oil recovery
EPA	U.S. Environmental Protection Agency
ERS	Economic Research Service
ETMS	Enhanced Traffic Management System
EVI	Enhanced Vegetation Index
FAA	Federal Aviation Administration
FAO	Food and Agricultural Organization

FCCC	Framework Convention on Climate Change
FEB	Fiber Economics Bureau
FERC	Federal Energy Regulatory Commission
FGD	Flue gas desulfurization
FHWA	Federal Highway Administration
FIA	Forest Inventory and Analysis
FIADB	Forest Inventory and Analysis Database
FIPR	Florida Institute of Phosphate Research
FQSV	First-quarter of silicon volume
FTP	Federal Test Procedure
g	Gram
GCV	Gross calorific value
GDP	Gross domestic product
Gg	Gigagram
GHG	Greenhouse gas
GHGRP	Greenhouse Gas Reporting Program
GRI	Gas Research Institute
GPG	Good Practice Guidance
Gg	Gigajoule
GSAM	Gas Systems Analysis Model
GWP	Global warming potential
ha	Hectare
HBFC	Hydrobromofluorocarbon
HC	Hydrocarbon
HCFC	Hydrochlorofluorocarbon
HDDV	Heavy duty diesel vehicle
HDGV	Heavy duty gas vehicle
HDPE	High density polyethylene
HFC	Hydrofluorocarbon
HFE	Hydrofluoroethers
HHV	Higher Heating Value
HMA	Hot Mix Asphalt
HTF	Heat Transfer Fluid
HTS	Harmonized Tariff Schedule
HWP	Harvested wood product
IBF	International bunker fuels
IC	Integrated Circuit
ICAO	International Civil Aviation Organization
IDB	Integrated Database
IEA	International Energy Association
IFO	Intermediate Fuel Oil
IISRP	International Institute of Synthetic Rubber Products
ILENR	Illinois Department of Energy and Natural Resources
IMO	International Maritime Organization
IPAA	Independent Petroleum Association of America
IPCC	Intergovernmental Panel on Climate Change
ITC	U.S. International Trade Commission
ITRS	International Technology Roadmap for Semiconductors
JWR	Jim Walters Resources
KCA	Key category analysis
kg	Kilogram
kWh	Kilowatt hour
LDDT	Light duty diesel truck
LDDV	Light duty diesel vehicle
LDGT	Light duty gas truck
LDGV	Light duty gas vehicle
LDPE	Low density polyethylene
LEV	Low emission vehicles
LFG	Landfill gas
LFGTE	Landfill gas-to-energy

LHV	Lower Heating Value
LKD	Lime kiln dust
LLDPE	Linear low density polyethylene
LMOP	EPA's Landfill Methane Outreach Program
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas(es)
LTO	Landing and take-off
LULUCF	Land use, land-use change, and forestry
MC	Motorcycle
MCF	Methane conversion factor
MCL	Maximum Contaminant Levels
MCFD	Thousand cubic feet per day
MDI	Metered dose inhalers
MECS	EIA Manufacturer's Energy Consumption Survey
MGO	Marine gas oil
MJ	Megajoule
MLRA	Major Land Resource Area
mm	Millimeter
MMBtu	Million British thermal units
MMCF	Million cubic feet
MMCFD	Million cubic feet per day
MMS	Minerals Management Service
MMT	Million Metric Tons
MMTCE	Million metric tons carbon equivalent
MODIS	Moderate Resolution Imaging Spectroradiometer
MoU	Memorandum of Understanding
MOVES	U.S. EPA's Motor Vehicle Emission Simulator model
MPG	Miles per gallon
MRLC	Multi-Resolution Land Characteristics Consortium
MRV	Monitoring, reporting, and verification
MSHA	Mine Safety and Health Administration
MSW	Municipal solid waste
MT	Metric ton
MTBE	Methyl Tertiary Butyl Ether
MTBS	Monitoring Trends in Burn Severity
N2O	Nitrous oxide
NA	Not available
NACWA	National Association of Clean Water Agencies
NAHMS	National Animal Health Monitoring System
NAICS	North American Industry Classification System
NAPAP	National Acid Precipitation and Assessment Program
NARR	North American Regional Reanalysis Product
NASA	National Aeronautics and Space Administration
NASF	National Association of State Foresters
NASS	USDA's National Agriculture Statistics Service
NC	No change
NCV	Net calorific value
NE	Not estimated
NEI	National Emissions Inventory
NEMA	National Electrical Manufacturers Association
NEMS	National Energy Modeling System
NESHAP	National Emission Standards for Hazardous Air Pollutants
NEU	Non-Energy Use
NEV	Neighborhood Electric Vehicle
NGHGI	National Greenhouse Gas Inventory
NGL	Natural gas liquids
NIR	National Inventory Report
NLCD	National Land Cover Dataset
NMOC	Non-methane organic compounds

NMVOC	Non-methane volatile organic compound
NO_x	Nitrogen oxides
NOAA	National Oceanic and Atmospheric Administratrion
NPRA	National Petroleum and Refiners Association
NRC	National Research Council
NRCS	Natural Resources Conservation Service
NRI	National Resources Inventory
NSCEP	National Service Center for Environmental Publications
NSCR	Non-selective catalytic reduction
NSPS	New source performance standards
NWS	National Weather Service
OAP	EPA Office of Atmospheric Programs
OAQPS	EPA Office of Air Quality Planning and Standards
ODP	Ozone depleting potential
ODS	Ozone depleting substances
OECD	Organization of Economic Co-operation and Development
OEM	Original equipment manufacturers
OMS	EPA Office of Mobile Sources
ORNL	Oak Ridge National Laboratory
OSHA	Occupational Safety and Health Administration
OTA	Office of Technology Assessment
OTAQ	EPA Office of Transportation and Air Quality
PAH	Polycyclic aromatic hydrocarbons
PCC	Precipitate calcium carbonate
PDF	Probability Density Function
PECVD	Plasma enhanced chemical vapor deposition
PET	Polyethylene terephthalate
PET	Potential evapotranspiration
PEVM	PFC Emissions Vintage Model
PFC	Perfluorocarbon
PFPE	Perfluoropolyether
POTW	Publicly Owned Treatment Works
Ppbv	Parts per billion (109) by volume
Ppm	Parts per million
Ppmv	Parts per million(106) by volume
Pptv	Parts per trillion (1012) by volume
PRP	Pasture/Range/Paddock
PS	Polystyrene
PSU	Primary Sample Unit
PU	Polyurethane
PVC	Polyvinyl chloride
PV	Photovoltaic
QA/QC	Quality Assurance and Quality Control
QBtu	Quadrillion Btu
R&D	Research and Development
RCRA	Resource Conservation and Recovery Act
RMA	Rubber Manufacturers' Association
RPA	Resources Planning Act
RTO	Regression-through-the-origin
SAE	Society of Automotive Engineers
SAGE	System for assessing Aviation's Global Emissions
SAN	Styrene Acrylonitrile
SAR	IPCC Second Assessment Report
SCR	Selective catalytic reduction
SEC	Securities and Exchange Commission
SEMI	Semiconductor Equipment and Materials Industry
SF_6	Sulfur hexafluoride
SICAS	Semiconductor International Capacity Statistics
SNAP	Significant New Alternative Policy Program
SNG	Synthetic natural gas

SOC	Soil Organic Carbon
SOG	State of Garbage survey
SSURGO	Soil Survey Geographic Database
STMC	Scrap Tire Management Council
SULEV	Super Ultra Low Emissions Vehicle
SWANA	Solid Waste Association of North America
SWDS	Solid waste disposal sites
TA	Treated anaerobically (wastewater)
TAM	Typical animal mass
TAME	Tertiary amyl methyl ether
TAR	IPCC Third Assessment Report
TBtu	Trillion Btu
TDN	Total digestible nutrients
TFI	The Fertilizer Institute
Tg	Teragrams
Tg CO_2 Eq.	Teragrams carbon dioxide equivalent
TIGER	Topologically Integrated Geographic Encoding and Referencing survey
TJ	Terajoule
TLEV	Traditional low emissions vehicle
TMLA	Total Manufactured Layer Area
TRI	Toxic Release Inventory
TSDF	Hazardous waste treatment, storage, and disposal facility
TVA	Tennessee Valley Authority
UAN	Urea ammonium nitrate
UDI	Utility Data Institute
UFORE	U.S. Forest Service's Urban Forest Effects model
UG	Underground (coal mining)
U.S.	United States
U.S. ITC	United States International Trade Commission
UEP	United Egg Producers
ULEV	Ultra low emission vehicle
UNEP	United Nations Environmental Programme
UNFCCC	United Nations Framework Convention on Climate Change
USAA	U.S. Aluminum Association
USAF	United States Air Force
USDA	United States Department of Agriculture
USFS	United States Forest Service
USGS	United States Geological Survey
VAIP	EPA's Voluntary Aluminum Industrial Partnership
VKT	Vehicle kilometers traveled
VMT	Vehicle miles traveled
VOCs	Volatile organic compounds
VS	Volatile solids
WERF	Water Environment Research Federation
WFF	World Fab Forecast (previously WFW, World Fab Watch)
WGC	World Gas Conference
WIP	Waste in place
WMO	World Meteorological Organization
WMS	Waste management systems
WW	Wastewater
WWTP	Wastewater treatment plant
ZEVs	Zero emissions vehicles

6.7. Chemical Formulas

Table A-287: Guide to Chemical Formulas

Symbol	Name
Al	Aluminum

Al_2O_3	Aluminum Oxide
Br	Bromine
C	Carbon
CH_4	Methane
C_2H_6	Ethane
C_3H_8	Propane
CF_4	Perfluoromethane
C_2F_6	Perfluoroethane, hexafluoroethane
$c\text{-}C_3F_6$	Perfluorocyclopropane
C_3F_8	Perfluoropropane
$c\text{-}C_4F_8$	Perfluorocyclobutane
C_4F_{10}	Perfluorobutane
C_5F_{12}	Perfluoropentane
C_6F_{14}	Perfluorohexane
CF_3I	Trifluoroiodomethane
$CFCl_3$	Trichlorofluoromethane (CFC-11)
CF_2Cl_2	Dichlorodifluoromethane (CFC-12)
CF_3Cl	Chlorotrifluoromethane (CFC-13)
$C_2F_3Cl_3$	Trichlorotrifluoroethane (CFC-113)*
CCl_3CF_3	CFC-113a*
$C_2F_4Cl_2$	Dichlorotetrafluoroethane (CFC-114)
C_2F_5Cl	Chloropentafluoroethane (CFC-115)
$CHCl_2F$	HCFC-21
CHF_2Cl	Chlorodifluoromethane (HCFC-22)
$C_2F_3HCl_2$	HCFC-123
C_2F_4HCl	HCFC-124
$C_2FH_3Cl_2$	HCFC-141b
$C_2H_3F_2Cl$	HCFC-142b
$CF_3CF_2CHCl_2$	HCFC-225ca
$CClF_2CF_2CHClF$	HCFC-225cb
CCl_4	Carbon tetrachloride
$CHClCCl_2$	Trichloroethylene
CCl_2CCl_2	Perchloroethylene, tetrachloroethene
CH_3Cl	Methylchloride
CH_3CCl_3	Methylchloroform
CH_2Cl_2	Methylenechloride
$CHCl_3$	Chloroform, trichloromethane
CHF_3	HFC-23
CH_2F_2	HFC-32
CH_3F	HFC-41
C_2HF_5	HFC-125
$C_2H_2F_4$	HFC-134
CH_2FCF_3	HFC-134a
$C_2H_3F_3$	HFC-143*
$C_2H_3F_3$	HFC-143a*
CH_2FCH_2F	HFC-152*
$C_2H_4F_2$	HFC-152a*
CH_3CH_2F	HFC-161
C_3HF_7	HFC-227ea
$CF_3CF_2CH_2F$	HFC-236cb
$CF_3CHFCHF_2$	HFC-236ea
$C_3H_2F_6$	HFC-236fa
$C_3H_3F_5$	HFC-245ca
$CHF_2CH_2CF_3$	HFC-245fa
$CF_3CH_2CF_2CH_3$	HFC-365mfc
$C_5H_2F_{10}$	HFC-43-10mee
CF_3OCHF_2	HFE-125
CF_2HOCF_2H	HFE-134
CH_3OCF_3	HFE-143a
$CF_3CHFOCF_3$	HFE-227ea

$CF_3CHClOCHF_2$	HCFE-235da2
$CF_3CHFOCHF_2$	HFE-236ea2
$CF_3CH_2OCF_3$	HFE-236fa
$CF_3CF_2OCH_3$	HFE-245cb2
$CHF_2CH_2OCF_3$	HFE-245fa1
$CF_3CH_2OCHF_2$	HFE-245fa2
$CHF_2CF_2OCH_3$	HFE-254cb2
$CF_3CH_2OCH_3$	HFE-263fb2
$CF_3CF_2OCF_2CHF_2$	HFE-329mcc2
$CF_3CF_2OCH_2CF_3$	HFE-338mcf2
$CF_3CF_2CF_2OCH_3$	HFE-347mcc3
$CF_3CF_2OCH_2CHF_2$	HFE-347mcf2
$CF_3CHFCF_2OCH_3$	HFE-356mec3
$CHF_2CF_2CF_2OCH_3$	HFE-356pcc3
$CHF_2CF_2OCH_2CHF_2$	HFE-356pcf2
$CHF_2CF_2CH_2OCHF_2$	HFE-356pcf3
$CF_3CF_2CH_2OCH_3$	HFE-365mcf3
$CHF_2CF_2OCH_2CH_3$	HFE-374pcf2
$C_4F_9OCH_3$	HFE-7100
$C_4F_9OC_2H_5$	HFE-7200
$CHF_2OCF_2OC_2F_4OCHF_2$	H-Galden 1040x
$CHF_2OCF_2OCHF_2$	HG-10
$CHF_2OCF_2CF_2OCHF_2$	HG-01
CH_3OCH_3	Dimethyl ether
CH_2Br_2	Dibromomethane
CH_2BrCl	Dibromochloromethane
$CHBr_3$	Tribromomethane
$CHBrF_2$	Bromodifluoromethane
CH_3Br	Methylbromide
CF_2BrCl	Bromodichloromethane (Halon 1211)
$CF_3Br(CBrF_3)$	Bromotrifluoromethane (Halon 1301)
CF_3I	FIC-13I1
CO	Carbon monoxide
CO_2	Carbon dioxide
$CaCO_3$	Calcium carbonate, Limestone
$CaMg(CO_3)_2$	Dolomite
CaO	Calcium oxide, Lime
Cl	atomic Chlorine
F	Fluorine
Fe	Iron
Fe_2O_3	Ferric oxide
$FeSi$	Ferrosilicon
H, H_2	atomic Hydrogen, molecular Hydrogen
H_2O	Water
H_2O_2	Hydrogen peroxide
OH	Hydroxyl
N, N_2	atomic Nitrogen, molecular Nitrogen
NH_3	Ammonia
NH_4^+	Ammonium ion
HNO_3	Nitric acid
NF_3	Nitrogen trifluoride
N_2O	Nitrous oxide
NO	Nitric oxide
NO_2	Nitrogen dioxide
NO_3	Nitrate radical
Na	Sodium
Na_2CO_3	Sodium carbonate, soda ash
Na_3AlF_6	Synthetic cryolite
O, O_2	atomic Oxygen, molecular Oxygen

O_3	Ozone
S	atomic Sulfur
H_2SO_4	Sulfuric acid
SF_6	Sulfur hexafluoride
SF_5CF_3	Trifluoromethylsulphur pentafluoride
SO_2	Sulfur dioxide
Si	Silicon
SiC	Silicon carbide
SiO_2	Quartz

* Distinct isomers.

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ANNEX 7 Uncertainty

The annual U.S. Inventory presents the best effort to produce estimates for greenhouse gas source and sink categories in the United States. These estimates were generated according to the UNFCCC reporting guidelines, following the recommendations set forth in the *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC/UNEP/OECD/IEA 1997), the *IPCC Good Practice Guidance* (IPCC 2000), the *Good Practice Guidance for Land Use, Land-Use Change and Forestry* (IPCC 2003), and the *2006 Guidelines for National Greenhouse Gas Inventories* (IPCC 2006). This Annex provides an overview of the uncertainty analysis conducted to support the U.S. Inventory, describes the sources of uncertainty characterized throughout the Inventory associated with various source categories (including emissions and sinks), and describes the methods through which uncertainty information was collected, quantified, and presented.

7.1. Overview

The current inventory emission estimates for some source categories, such as for CO_2 Emissions from Fossil Fuel Combustion, have relatively low level of uncertainty associated with them. However, for some other source categories, the inventory emission estimates are considered less certain. The two major types of uncertainty associated with these emission estimates are (1) model uncertainty, which arises when the emission and/or removal estimation models used in developing the inventory estimates do not fully and accurately characterize the respective emission and/or removal processes (due to a lack of technical details or other resources), resulting in the use of incorrect or incomplete estimation methodologies and (2) parameter uncertainty, which arises due to a lack of precise input data such as emission factors and activity data.

The model uncertainty can be partially analyzed by comparing the model results with those of other models developed to characterize the same emission (or removal) process, after taking into account the differences in their conceptual framework, capabilities, data and assumptions. However, it would be very difficult—if not impossible—to quantify the model uncertainty associated with the emission estimates (primarily because, in most cases, only a single model has been developed to estimate emissions from any one source). Therefore, model uncertainty was not quantified in this report. Nonetheless, it has been discussed qualitatively, where appropriate, along with the individual source category description and inventory estimation methodology.

Parameter uncertainty is, therefore, the principal type and source of uncertainty associated with the national inventory emission estimates and is the main focus of the quantitative uncertainty analyses in this report. Parameter uncertainty has been quantified for all of the emission sources and sinks in the U.S. Inventory, with the exception of one very small emission source category, CH_4 emissions from Incineration of Waste, which was included in the *1990-2008 National GHG Inventory* for the first time, and two other source categories (International Bunker Fuels and biomass energy consumption) whose emissions are not included in the Inventory totals.

The primary purpose of the uncertainty analysis conducted in support of the U.S. Inventory is (i) to determine the quantitative uncertainty associated with the emission (and removal) estimates presented in the main body of this report [based on the uncertainty associated with the input parameters used in the emission (and removal) estimation methodologies] and (ii) to evaluate the relative importance of the input parameters in contributing to uncertainty in the associated source category inventory estimate and in the overall inventory estimate. Thus, the U.S. Inventory uncertainty analysis provides a strong foundation for developing future improvements and revisions to the Inventory estimation process. For each source category, the analysis highlights opportunities for changes to data measurement, data collection, and calculation methodologies. These are presented in the “Planned Improvements” sections of each source category’s discussion in the main body of the report.

7.2. Methodology and Results

The United States has developed a quality assurance and quality control (QA/QC) and uncertainty management plan (EPA 2002) in accordance with the IPCC *Good Practice Guidance* (IPCC 2000). Like the QA/QC plan, the uncertainty management plan is part of a continually evolving process. The uncertainty management plan provides for a quantitative assessment of the inventory analysis itself, thereby contributing to continuing efforts to understand both what causes uncertainty and how to improve inventory quality. Although the plan provides both general and specific guidelines for implementing quantitative uncertainty analysis, its components are intended to evolve over time, consistent with the inventory estimation process. The U.S. plan includes procedures and guidelines, and forms and templates, for developing quantitative assessments of uncertainty in the national Inventory estimates (EPA 2002).

The IPCC *Good Practice Guidance* recommends two approaches—Tier 1 and Tier 2—for developing quantitative estimates of uncertainty in the inventory estimate of individual source categories and the overall inventory. Of these, the Tier 2 approach is both more flexible and reliable than Tier 1; both methods are described in the next section. The United States is in the process of implementing a multi-year strategy to develop quantitative estimates of uncertainty for all source categories using the Tier 2 approach. For the current Inventory, a Tier 2 approach was implemented for all source categories with the exception of Composting and parts of Agricultural Soil Management source categories.

The current Inventory reflects significant improvements over the previous publication in the extent to which the Tier 2 approach to uncertainty analysis was adopted. Each of the new Tier 2 analyses reflects additional detail and characterization of input parameters using statistical data collection, expert elicitation methods and more informed judgment. In following the UNFCCC requirement under Article 4.1, emissions from International Bunker Fuels and Indirect Greenhouse Gas Emissions are not included in the total emissions estimated for the U.S. Inventory; therefore, no quantitative uncertainty estimates have been developed for these source categories.[113] Emissions from biomass combustion are accounted for implicitly in the LULUCF chapter through the calculation of changes in carbon stocks. The Energy sector does provide an estimate of CO_2 emissions from bioenergy consumption provided as a memo item for informational purposes in line with the UNFCCC reporting requirements.

Tier 1 and Tier 2 Approach

The Tier 1 method for estimating uncertainty is based on the error propagation equation. This equation combines the uncertainty associated with the activity data and the uncertainty associated with the emission (or the other) factors. The Tier 1 approach is applicable where emissions (or removals) are usually estimated as the product of an activity value and an emission factor or as the sum of individual sub-source category values. Inherent in employing the Tier 1 method are the assumptions that, for each source category, (i) both the activity data and the emission factor values are approximately normally distributed, (ii) the coefficient of variation (i.e., the ratio of the standard deviation to the mean) associated with each input variable is less than 30 percent, and (iii) the input variables within and across (sub-) source categories are not correlated (i.e., value of each variable is independent of the values of other variables).

The Tier 2 method is preferred (i) if the uncertainty associated with the input variables is significantly large, (ii) if the distributions underlying the input variables are not normal, (iii) if the estimates of uncertainty associated with the input variables are correlated, and/or (iv) if a sophisticated estimation methodology and/or several input variables are used to characterize the emission (or removal) process correctly. In practice, the Tier 2 is the preferred method of uncertainty analysis for all source categories where sufficient and reliable data are available to characterize the uncertainty of the input variables.

The Tier 2 method employs the Monte Carlo Stochastic Simulation technique (also referred to as the Monte Carlo method). Under this method, estimates of emissions (or removals) for a particular source category are generated many times (equal to the number of simulations specified) using an uncertainty model, which is an emission (or removal) estimation equation that imitates or is the same as the inventory estimation model for a particular source category. These estimates are generated using the respective, randomly-selected values for the constituent input variables using commercially available simulation software such as *@RISK* or *Crystal Ball*.

Characterization of Uncertainty in Input Variables

Both Tier 1 and Tier 2 uncertainty analyses require that all the input variables are well-characterized in terms of their Probability Density Functions (PDFs). In the absence of particularly convincing data measurements, sufficient data samples, or expert judgments that determined otherwise, the PDFs incorporated in the current source category uncertainty

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[113] However, because the input variables that determine the emissions from the Fossil Fuel Combustion and the International Bunker Fuels source categories are correlated, uncertainty associated with the activity variables in the International Bunker Fuels was taken into account in estimating the uncertainty associated with the Fossil Fuel Combustion.

analyses were limited to normal, lognormal, uniform, triangular, and beta distributions. The choice among these five PDFs depended largely on the observed or measured data and expert judgment.

Source Category Inventory Uncertainty Estimates

Discussion surrounding the input parameters and sources of uncertainty for each source category appears in the body of this report. Table A-288 summarizes results based on assessments of source category-level uncertainty. The table presents base year (1990 or 1995) and current year (2012) emissions for each source category. The combined uncertainty (at the 95 percent confidence interval) for each source category is expressed as the percentage deviation above and below the total 2012 emissions estimated for that source category. Source category trend uncertainty is described subsequently in this Appendix.

Table A-288: Summary Results of Source Category Uncertainty Analyses

Source Category	Base Year Emissions[i,a]	2012 Emissions[a]	2012 Uncertainty[b]	
	Tg CO_2 Eq.	Tg CO_2 Eq.	Low	High
CO_2	**5,076.7**	**5,382.8**	-2%	5%
Fossil Fuel Combustion[c]	4,708.9	5,071.9	-2%	5%
Non-Energy Use of Fuels	117.0	110.3	-21%	35%
Iron and Steel Production & Metallurgical Coke Production	109.8	54.3	-16%	17%
Natural Gas Systems	33.7	35.2	-19%	30%
Cement Production	33.3	35.1	-6%	6%
Lime Production	11.5	13.3	-3%	3%
Incineration of Waste	10.9	12.2	-10%	13%
Ammonia Production	16.8	9.4	-6%	7%
Other Process Uses of Carbonates	5.1	8.0	-14%	21%
Cropland Remaining Cropland	7.1	7.4	-57%	69%
Urea Consumption for Non-Agricultural Purposes	0.0	5.2	-9%	10%
Petrochemical Production	2.2	3.5	-25%	28%
Aluminum Production	6.8	3.4	-2%	2%
Soda Ash Production and Consumption	4.1	2.7	-6%	5%
Carbon Dioxide Consumption	1.4	1.8	-38%	43%
Titanium Dioxide Production	1.2	1.7	-12%	13%
Ferroalloy Production	2.2	1.7	-12%	12%
Zinc Production	0.9	1.4	-16%	17%
Glass Production	NA	1.2	-5%	4%
Phosphoric Acid Production	1.5	1.1	-19%	21%
Wetlands Remaining Wetlands	1.0	0.8	-26%	30%
Lead Production	0.3	0.5	-14%	15%
Petroleum Systems	0.4	0.4	-24%	149%
Silicon Carbide Production and Consumption	0.4	0.2	-9%	9%
Land Use, Land-Use Change, and Forestry (Sink)[d]	-841.4	-979.3	18%	-15%
Wood Biomass[e]	*0.0*	*194.1*	*NE*	*NE*
International Bunker Fuels[f]	*114.3*	*105.8*	*NE*	*NE*
Biomass – Ethanol[e]	*219.3*	*72.9*	*NE*	*NE*
CH_4	**616.6**	**567.3**	-10%	18%
Enteric Fermentation	133.2	141.0	-11%	18%
Natural Gas Systems	129.6	129.9	-19%	30%
Landfills	149.2	102.8	-56%	49%
Coal Mining	84.1	55.8	-4%	35%
Manure Management	30.4	52.9	-18%	20%
Petroleum Systems	33.9	31.7	-24%	149%
Forest Land Remaining Forest Land	4.6	15.3	-82%	176%
Wastewater Treatment	23.5	12.8	-27%	21%
Rice Cultivation	7.1	7.4	-52%	96%
Stationary Combustion	7.4	5.7	-36%	132%

Abandoned Underground Coal Mines	6.0	4.7	-19%	26%
Petrochemical Production	0.9	3.1	-10%	10%
Mobile Combustion	4.2	1.7	-12%	16%
Composting	0.3	1.6	-50%	50%
Iron and Steel Production & Metallurgical Coke Production	1.0	0.6	-21%	22%
Field Burning of Agricultural Residues	0.7	0.3	-41%	42%
Ferroalloy Production	0.0	0.0	-11%	11%
Silicon Carbide Production and Consumption	0.0	0.0	-9%	10%
Incineration of Waste	*0.0*	*0.0*	*NE*	*NE*
International Bunker Fuels[f]	*0.2*	*0.1*	*NE*	*NE*
N_2O	**315.0**	**410.1**	-8%	32%
Agricultural Soil Management	200.3	306.6	NE	NE
Stationary Combustion	12.8	22.0	-20%	51%
Manure Management	12.1	18.0	-16%	24%
Mobile Combustion	40.4	16.5	-3%	27%
Nitric Acid Production	20.0	15.3	-37%	38%
Forest Land Remaining Forest Land	0.5	12.8	-66%	146%
Adipic Acid Production	15.3	5.8	-4%	4%
Wastewater Treatment	3.7	5.0	-75%	100%
N_2O from Product Uses	4.4	4.4	-24%	24%
Composting	0.4	1.8	-50%	50%
Settlements Remaining Settlements	1.0	1.5	-49%	163%
Incineration of Waste	0.5	0.4	-48%	322%
Field Burning of Agricultural Residues	0.4	0.1	-30%	32%
Wetlands Remaining Wetlands	0.0	0.0	-73%	38%
International Bunker Fuels[f]	*1.1*	*1.0*	*NE*	*NE*
HFCs, PFCs, and SF_6	**90.5**	**161.9**	0%	13%
Substitution of Ozone Depleting Substances[g]	28.5	143.6	0%	14%
Electrical Transmission and Distribution	26.8	6.0	-18%	25%
HCFC-22 Production	36.4	4.3	-7%	10%
Semiconductor Manufacture	2.9	3.7	-5%	5%
Aluminum Production	18.5	2.5	-5%	6%
Magnesium Production	5.4	1.7	-11%	12%
Total[h]	**6,098.7**	**6,522.0**	**-1%**	**5%**
Net Emissions (Sources and Sinks)[h]	**5,257.3**	**5,542.7**	**-2%**	**7%**

Notes:

Totals may not sum due to independent rounding.

NE: Not Estimated

\+ Does not exceed 0.05 Tg CO_2 Eq.

[a] Emission estimates reported in this table correspond to emissions from only those source categories for which quantitative uncertainty was performed for the current Inventory. Thus the totals reported for 2012 in this table exclude approximately 3.6 Tg CO_2 Eq. of emissions for which quantitative uncertainty was not assessed. Hence, these emission estimates do not match the final total U.S. greenhouse gas emission estimates presented in this Inventory. All uncertainty estimates correspond only to the totals reported in this table.

[b] The uncertainty estimates correspond to a 95 percent confidence interval, with the lower bound corresponding to 2.5th percentile and the upper bound corresponding to 97.5th percentile.

[c] This source category's inventory estimates exclude CO_2 emissions from geothermal sources, as quantitative uncertainty analysis was not performed for that sub-source category. Hence, for this source category, the emissions reported in this table do not match the emission estimates presented in the Energy chapter of the Inventory.

[d] Sinks are only included in Net Emissions.

[e] Emissions from Wood Biomass and Ethanol Consumption are not included specifically in summing energy sector totals.

[f] Emissions from International Bunker Fuels are not included in the totals.

[g] This source category's estimate for 2012 excludes 3.8 Tg of CO_2 Eq. from several very small emission sources, as uncertainty associated with those sources was not assessed. Hence, for this source category, the emissions reported in this table do not match the emission estimates presented in the Industrial Processes chapter of the Inventory.

[h] Totals exclude emissions for which uncertainty was not quantified. .

[I] Base Year is 1990 for all sources except Substitution of Ozone Depleting Substances, for which the United States has chosen 1995.

Overall (Aggregate) Inventory Level Uncertainty Estimates

The overall level uncertainty estimate for the U.S. greenhouse gas emissions inventory was developed using the IPCC Tier 2 uncertainty estimation methodology. The uncertainty models of all the emission source categories could not be directly integrated to develop the overall uncertainty estimates due to software constraints in integrating multiple, large uncertainty models. Therefore, an alternative approach was adopted to develop the overall uncertainty estimates. The Monte Carlo simulation output data for each emission source category uncertainty analysis were combined by type of gas and the probability distributions were fitted to the combined simulation output data, where such simulated output data were available. If such detailed output data were not available for particular emissions sources, individual probability distributions were assigned to those source category emission estimates based on the most detailed data available from the quantitative uncertainty analysis performed.

For the Composting and for parts of Agricultural Soil Management source categories, Tier 1 uncertainty results were used in the overall uncertainty analysis estimation. However, for all other emission sources (excluding international bunker fuels, CO_2 from biomass combustion, and CH_4 from incineration of waste), Tier 2 uncertainty results were used in the overall uncertainty estimation.

The overall uncertainty model results indicate that the 2012 U.S. greenhouse gas emissions are estimated to be within the range of approximately 6,448 to 6,873 Tg CO_2 Eq., reflecting a relative 95 percent confidence interval uncertainty range of -1 percent to 5 percent with respect to the total U.S. greenhouse gas emission estimate of approximately 6,522 Tg CO_2 Eq. The uncertainty interval associated with total CO_2 emissions, which constitute about 83 percent of the total U.S. greenhouse gas emissions in 2011, ranges from -2 percent to 5 percent of total CO_2 emissions estimated. The results indicate that the uncertainty associated with the inventory estimate of the total CH_4 emissions ranges from -10 percent to 18 percent, uncertainty associated with the total inventory N_2O emission estimate ranges from -8 percent to 32 percent, and uncertainty associated with high GWP gas emissions ranges from 0 percent to 13 percent.

A summary of the overall quantitative uncertainty estimates is shown below.

Table A-289. Quantitative Uncertainty Assessment of Overall National Inventory Emissions (Tg CO_2 Eq. and Percent)

Gas	2012 Emission Estimate[a] (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[b] (Tg CO_2 Eq.)		(%)		Mean[c] (Tg CO_2 Eq.)	Standard Deviation[c] (Tg CO_2 Eq.)
		Lower Bound[d]	Upper Bound[d]	Lower Bound	Upper Bound		
CO_2	5,382.8	5,265	5,630	-2%	5%	5,448	93
CH_4[e]	567.3	513	671	-10%	18%	586	40
N_2O[e]	410.1	378	540	-8%	32%	452	41
PFC, HFC & SF_6[e]	161.9	161	182	0%	13%	172	5
Total	**6,522.0**	**6,448**	**6,873**	**-1%**	**5%**	**6,658**	**109**
Net Emissions (Sources and Sinks)	**5,542.7**	**5,420**	**5,940**	**-2%**	**7%**	**5,681**	**134**

Notes:

[a] Emission estimates reported in this table correspond to emissions from only those source categories for which quantitative uncertainty was performed this year. Thus the totals reported in this table exclude approximately 3.6 Tg CO_2 Eq. of emissions for which quantitative uncertainty was not assessed. Hence, these emission estimates do not match the final total U.S. greenhouse gas emission estimates presented in this Inventory.

[b] The lower and upper bounds for emission estimates correspond to a 95 percent confidence interval, with the lower bound corresponding to 2.5th percentile and the upper bound corresponding to 97.5th percentile.

[c] Mean value indicates the arithmetic average of the simulated emission estimates; standard deviation indicates the extent of deviation of the simulated values from the mean.

[d] The lower and upper bound emission estimates for the sub-source categories do not sum to total emissions because the low and high estimates for total emissions were calculated separately through simulations.

[e] The overall uncertainty estimates did not take into account the uncertainty in the GWP values for CH_4, N_2O and high GWP gases used in the inventory emission calculations for 2012.

Trend Uncertainty

In addition to the estimates of uncertainty associated with the current year's emission estimates, this Annex also presents the estimates of trend uncertainty. The *IPCC Good Practice Guidance* defines trend as the difference in emissions between the base year (i.e., 1990) and the current year (i.e., 2012) inventory estimates. However, for purposes of understanding the concept of trend uncertainty, the emission trend is defined in this Inventory as the percentage change in the emissions (or removal) estimated for the current year, relative to the emission (or removal) estimated for the base year. The uncertainty associated with this emission trend is referred to as trend uncertainty.

Under the Tier 1 approach, the trend uncertainty for a source category is estimated using the sensitivity of the calculated difference between the base year and the current year (i.e., 2012) emissions to an incremental (i.e., 1 percent) increase in one or both of these values for that source category. The two sensitivities are expressed as percentages: Type A sensitivity highlights the effect on the difference between the base and the current year emissions caused by a 1 percent change in both, while Type B sensitivity highlights the effect caused by a change to only the current year's emissions. Both sensitivities are simplifications introduced in order to analyze the correlation between the base and the current year estimates. Once calculated, the two sensitivities are combined using the error propagation equation to estimate the overall trend uncertainty.

Under the Tier 2 approach, the trend uncertainty is estimated using Monte Carlo Stochastic Simulation technique. The trend uncertainty analysis takes into account the fact that the base and the current year estimates often share input variables. For purposes of the current Inventory, a simple approach has been adopted, under which the base year source category emissions (or removals) are assumed to exhibit the same uncertainty characteristics as the current year emissions (or removals). Source category-specific PDFs for base year estimates were developed using current year (i.e., 2012) uncertainty output data. These were adjusted to account for differences in magnitude between the two years' inventory estimates. Then, for each source category, a trend uncertainty estimate was developed using the Monte Carlo method. The overall inventory trend uncertainty estimate was developed by combining all source category-specific trend uncertainty estimates. These trend uncertainty estimates present the range of likely change from base year to 2012, and are shown in Table A- 290.

Table A- 290. Quantitative Assessment of Trend Uncertainty (Tg CO$_2$ Eq. and Percent)

Gas/Source	Base Year Emissions[i,a]	2012 Emissions[a]	Emissions Trend[a]	Trend Range[a,b]	
	(Tg CO2 Eq.)		(%)	(%)	
				Lower Bound	Upper Bound
CO$_2$	**5,108.3**	**5,382.8**	**5%**	**1%**	**11%**
Fossil Fuel Combustion[c]	4,744.7	5,071.9	7%	2%	12%
Non-Energy Use of Fuels	120.8	110.3	-9%	-37%	35%
Iron and Steel Production & Metallurgical Coke Production	99.8	54.3	-46%	-57%	-31%
Natural Gas Systems	37.7	35.2	-7%	-34%	31%
Cement Production	33.3	35.1	5%	-4%	15%
Ammonia Production	13.0	9.4	-28%	-35%	-21%
Lime Production	11.4	13.3	17%	12%	21%
Incineration of Waste	8.0	12.2	53%	30%	81%
Cropland Remaining Cropland	7.1	7.4	4%	-60%	161%
Aluminum Production	6.8	3.4	-50%	-51%	-48%
Other Process Uses of Carbonates	4.9	8.0	63%	27%	108%
Urea Consumption for Non-Ag Purposes	3.8	5.2	39%	21%	59%
Petrochemical Production	3.4	3.5	2%	-28%	59%
Soda Ash Production and Consumption	2.7	2.7	-3%	-9%	5%
Ferroalloy Production	2.2	1.7	-23%	-35%	-8%
Phosphoric Acid Production	1.6	1.1	-31%	-48%	-7%
Glass Production	1.5	1.2	-19%	-24%	-13%
Carbon Dioxide Consumption	1.4	1.8	28%	-38%	71%
Titanium Dioxide Production	1.2	1.7	46%	13%	62%
Wetlands Remaining Wetlands	1.0	0.8	-20%	-47%	21%
Zinc Production	0.6	1.4	125%	77%	186%
Lead Production	0.5	0.5	2%	-20%	23%
Petroleum Systems	0.4	0.4	3%	-55%	136%
Silicon Carbide Production and Consumption	0.4	0.2	-58%	-68%	-58%
Land Use, Land-Use Change, and Forestry (Sink)a	-831.1	-979.3	18%	1%	38%
Biomass – Wood[e]	*214.4*	*194.1*	*-9%*	*NE*	*NE*
International Bunker Fuels[f]	*103.5*	*105.8*	*2%*	*NE*	*NE*
Biomass – Ethanol[e]	*4.2*	*72.9*	*1624%*	*NE*	*NE*
CH$_4$	**635.7**	**567.3**	**-11%**	**-31%**	**3%**
Natural Gas Systems	156.4	129.9	-17%	-41%	19%
Landfills	147.8	102.8	-30%	-72%	65%

Enteric Fermentation	137.9	141.0	2%	-17%	25%
Coal Mining	81.1	55.8	-31%	-56%	-33%
Petroleum Systems	35.8	31.7	-11%	-61%	103%
Manure Management	31.5	52.9	68%	13%	134%
Wastewater Treatment	13.2	12.8	-3%	-73%	-7%
Rice Cultivation	7.7	7.4	-4%	-64%	160%
Stationary Combustion	7.5	5.7	-24%	-72%	106%
Abandoned Underground Coal Mines	6.0	4.7	-22%	-51%	16%
Mobile Combustion	4.6	1.7	-63%	-70%	-54%
Forest Land Remaining Forest Land	2.5	15.3	511%	-14%	4341%
Petrochemical Production	2.3	3.1	36%	243%	554%
Iron and Steel Production & Metallurgical Coke Production	1.0	0.6	-36%	-44%	5%
Composting	0.3	1.6	397%	120%	1025%
Field Burning of Agricultural Residues	0.3	0.3	-6%	-49%	80%
Ferroalloy Production	+	+	-31%	-42%	-19%
Silicon Carbide Production and Consumption	+	+	-67%	-71%	-62%
Incineration of Waste	+	+	-23%	NE	NE
International Bunker Fuels[f]	*0.1*	*0.1*	*-37%*	*NE*	*NE*
N_2O	**398.6**	**410.1**	**3%**	**-26%**	**43%**
Agricultural Soil Management	282.1	306.6	9%	-33%	79%
Mobile Combustion	44.0	16.5	-62%	-69%	-54%
Nitric Acid Production	18.2	15.3	-16%	-58%	39%
Adipic Acid Production	15.8	5.8	-64%	-35%	-15%
Manure Management	14.4	18.0	25%	-5%	64%
Stationary Combustion	12.3	22.0	79%	13%	182%
N_2O from Product Uses	4.4	4.4	0%	-26%	28%
Wastewater Treatment	3.5	5.0	45%	-68%	553%
Forest Land Remaining Forest Land	2.1	12.8	509%	29%	2690%
Settlements Remaining Settlements	1.0	1.5	48%	-53%	378%
Incineration of Waste	0.5	0.4	-23%	-83%	259%
Composting	0.4	1.8	397%	125%	1009%
Field Burning of Agricultural Residues	0.1	0.1	2%	-34%	62%
Wetlands Remaining Wetlands	+	+	-31%	-79%	130%
International Bunker Fuels[f]	*0.9*	*1.0*	*8%*	*NE*	*NE*
HFCs, PFCs, and SF6	**121.2**	**161.9**	**34%**	**27%**	**50%**
HCFC-22 Production	36.4	4.3	-88%	-89%	-87%
Substitution of Ozone Depleting Substances	31.3	143.6	358%	317%	404%
Electrical Transmission and Distribution	26.7	6.0	-77%	-83%	-70%
Aluminum Production	18.4	2.5	-86%	-87%	-85%
Magnesium Production and Processing	5.4	1.7	-69%	-73%	-63%
Semiconductor Manufacture	2.9	3.7	28%	19%	38%
Total[h]	**6,263.8**	**6,522.0**	**4%**	**-1%**	**9%**
Net Emission (Sources and Sinks)	**5,432.7**	**5,542.7**	**2%**	**-5%**	**8%**

Notes:

Totals may not sum due to independent rounding.

NE: Not Estimated

+ Does not exceed 0.05 Tg CO_2 Eq.

[a] Emission estimates reported in this table correspond to emissions from only those source categories for which quantitative uncertainty was performed for the current Inventory. Thus the totals reported for 2011 in this table exclude approximately 3.6 Tg CO_2 Eq. of emissions for which quantitative uncertainty was not assessed. Hence, these emission estimates do not match the final total U.S. greenhouse gas emission estimates presented in this Inventory. All uncertainty estimates correspond only to the totals reported in this table.

[b] The trend range represents a 95 percent confidence interval for the emission trend, with the lower bound corresponding to 2.5th percentile value and the upper bound corresponding to 97.5th percentile value.

[c] This source category's inventory estimates exclude CO_2 emissions from geothermal sources, as quantitative uncertainty analysis was not performed for that sub-source category. Hence, for this source category, the emissions reported in this table do not match the emission estimates presented in the Energy chapter of the Inventory.

[d] Sinks are only included in Net Emissions.

[e] Emissions from Wood Biomass and Ethanol Consumption are not included specifically in summing energy sector totals.

[f] Emissions from International Bunker Fuels are not included in the totals.

[g] This source category's estimate for 2011 excludes 3.8 Tg of CO_2 Eq. from several very small emission sources, as uncertainty associated with those sources was not assessed. Hence, for this source category, the emissions reported in this table do not match the emission estimates presented in the Industrial Processes chapter of the Inventory.

[h] Totals exclude emissions for which uncertainty was not quantified. .

[1] Base Year is 1990 for all sources except Substitution of Ozone Depleting Substances, for which the United States has chosen 1995.

7.3. Planned Improvements

Identifying the sources of uncertainty in the emission and sink estimates of the Inventory and quantifying the magnitude of the associated uncertainty is the crucial first step towards improving those estimates. Quantitative assessment of the parameter uncertainty may also provide information about the relative importance of input parameters (such as activity data and emission factors), based on their relative contribution to the uncertainty within the source category estimates. Such information can be used to prioritize resources with a goal of reducing uncertainty over time within or among inventory source categories and their input parameters. In the current Inventory, potential sources of model uncertainty have been identified for some emission source categories, and uncertainty estimates based on their parameters' uncertainty have been developed for all the emission source categories, with the exception of CH_4 from incineration of waste, which is a minor emission source category newly added to the Inventory starting with the 2008 business year, and the international bunker fuels and wood biomass and ethanol combustion source categories, which are not included in the energy sector totals. Emissions from biomass and ethanol combustion however are accounted for implicitly in the LULUCF chapter through the calculation of changes in carbon stocks. The Energy sector does provide an estimate of CO_2 emissions from bioenergy consumption provided as a memo item for informational purposes.

Specific areas that require further research include:

- *Incorporating excluded emission sources.* Quantitative estimates for some of the sources and sinks of greenhouse gas emissions, such as from some land-use activities, industrial processes, and parts of mobile sources, could not be developed at this time either because data are incomplete or because methodologies do not exist for estimating emissions from these source categories. See Annex 5 of this report for a discussion of the sources of greenhouse gas emissions and sinks excluded from this report. In the future, efforts will focus on estimating emissions from excluded emission sources and developing uncertainty estimates for all source categories for which emissions are estimated.
- *Improving the accuracy of emission factors.* Further research is needed in some cases to improve the accuracy of emission factors used to calculate emissions from a variety of sources. For example, the accuracy of current emission factors applied to CH_4 and N_2O emissions from stationary and mobile combustion are highly uncertain.
- *Collecting detailed activity data.* Although methodologies exist for estimating emissions for some sources, problems arise in obtaining activity data at a level of detail in which aggregate emission factors can be applied. For example, the ability to estimate emissions of SF_6 from electrical transmission and distribution is limited due to a lack of activity data regarding national SF_6 consumption or average equipment leak rates.

In improving the quality of uncertainty estimates the following include areas that deserve further attention:

- *Refine Source Category and Overall Uncertainty Estimates.* For many individual source categories, further research is needed to more accurately characterize PDFs that surround emissions modeling input variables. This might involve using measured or published statistics or implementing rigorous elicitation protocol to elicit expert judgments, if published or measured data are not available.
- *Include GWP uncertainty in the estimation of Overall level and trend uncertainty.* The current year's Inventory does not include the uncertainty associated with the GWP values in the estimation of the overall uncertainty for the Inventory. Including this source would contribute to a better characterization of overall uncertainty and help assess the level of attention that this source of uncertainty warrants in the future.
- *Improve characterization of trend uncertainty associated with base year Inventory estimates.* The characterization of base year uncertainty estimates could be improved, by developing explicit uncertainty models for the base year. This would then improve the analysis of trend uncertainty. However, not all of the simplifying assumptions described in the "Trend Uncertainty" section above may be eliminated through this process due to a lack of availability of more appropriate data.

7.4. Additional Information on Uncertainty Analyses by Source

The quantitative uncertainty estimates associated with each emission and sink source category are reported in each chapter of this Inventory following the discussions of inventory estimates and their estimation methodology. This section provides additional descriptions of the uncertainty analyses performed for some of the sources, including the models and methods used to calculate the emission estimates and the potential sources of uncertainty surrounding them. These sources are organized below in the same order as the sources in each chapter of the main section of this Inventory. To avoid repetition, the following uncertainty analysis discussions of individual source categories do not include descriptions of these source categories. Hence, to better understand the details provided below, refer to the respective chapters and sections in the main section of this Inventory, as needed. All uncertainty estimates are reported relative to the 2012 Inventory estimates for the 95 percent confidence interval, unless otherwise specified.

Energy

The uncertainty analysis descriptions in this section correspond to source categories included in the Energy Chapter of the Inventory.

CO_2 from Fossil Fuel Combustion

For estimates of CO_2 from fossil fuel combustion, the amount of CO_2 emitted is directly related to the amount of fuel consumed, the fraction of the fuel that is oxidized, and the carbon content of the fuel. Therefore, a careful accounting of fossil fuel consumption by fuel type, average carbon contents of fossil fuels consumed, and production of fossil fuel-based products with long-term carbon storage should yield an accurate estimate of CO_2 emissions.

Nevertheless, there are uncertainties in the consumption data, carbon content of fuels and products, and carbon oxidation efficiencies. For example, given the same primary fuel type (e.g., coal, petroleum, or natural gas), the amount of carbon contained in the fuel per unit of useful energy can vary. For the United States, however, the impact of these uncertainties on overall CO_2 emission estimates is believed to be relatively small. See, for example, Marland and Pippin (1990).

Although statistics of total fossil fuel and other energy consumption are relatively accurate, the allocation of this consumption to individual end-use sectors (i.e., residential, commercial, industrial, and transportation) is less certain. For example, for some fuels the sectoral allocations are based on price rates (i.e., tariffs), but a commercial establishment may be able to negotiate an industrial rate or a small industrial establishment may end up paying an industrial rate, leading to a misallocation of emissions. Also, the deregulation of the natural gas industry and the more recent deregulation of the electric power industry have likely led to some minor problems in collecting accurate energy statistics as firms in these industries have undergone significant restructuring.

To calculate the total CO_2 emission estimate from energy-related fossil fuel combustion, the amount of fuel used in these non-energy production processes were subtracted from the total fossil fuel consumption. The amount of CO_2 emissions resulting from non-energy related fossil fuel use has been calculated separately and reported in the Carbon Emitted from Non-Energy Uses of Fossil Fuels section of this report. These factors all contribute to the uncertainty in the CO_2 estimates. Detailed discussions on the uncertainties associated with C emitted from Non-Energy Uses of Fossil Fuels can be found within that section of this chapter.

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

Uncertainties in the emission estimates presented above also result from the data used to allocate CO_2 emissions from the transportation end-use sector to individual vehicle types and transport modes. In many cases, bottom-up estimates of fuel consumption by vehicle type do not match aggregate fuel-type estimates from EIA. Further research is planned to improve the allocation into detailed transportation end-use sector emissions.

The uncertainty analysis was performed by primary fuel type for each end-use sector, using the IPCC-recommended Tier 2 uncertainty estimation methodology, Monte Carlo Stochastic Simulation technique, with @RISK software. For this uncertainty estimation, the inventory estimation model for CO_2 from fossil fuel combustion was integrated with the relevant variables from the inventory estimation model for International Bunker Fuels, to realistically characterize the interaction (or endogenous correlation) between the variables of these two models. About 120 input variables were modeled for CO_2 from energy-related Fossil Fuel Combustion (including about 10 for non-energy fuel consumption and about 20 for International Bunker Fuels).

In developing the uncertainty estimation model, uniform distributions were assumed for all activity-related input variables and emission factors, based on the SAIC/EIA (2001) report.[114] Triangular distributions were assigned for the oxidization factors (or combustion efficiencies). The uncertainty ranges were assigned to the input variables based on the data reported in SAIC/EIA (2001) and on conversations with various agency personnel.[115]

The uncertainty ranges for the activity-related input variables were typically asymmetric around their inventory estimates; the uncertainty ranges for the emissions factors were symmetric. Bias (or systematic uncertainties) associated with these variables accounted for much of the uncertainties associated with these variables (SAIC/EIA 2001).[116] For purposes of this uncertainty analysis, each input variable was simulated 10,000 times through Monte Carlo Sampling.

CH_4 and N_2O from Stationary Combustion

Methane emission estimates from stationary sources exhibit high uncertainty, primarily due to difficulties in calculating emissions from wood combustion (i.e., fireplaces and wood stoves). The estimates of CH_4 and N_2O emissions presented are based on broad indicators of emissions (i.e., fuel use multiplied by an aggregate emission factor for different sectors), rather than specific emission processes (i.e., by combustion technology and type of emission control).

An uncertainty analysis was performed by primary fuel type for each end-use sector, using the IPCC-recommended Tier 2 uncertainty estimation methodology, Monte Carlo Stochastic Simulation technique, with @RISK software.

The uncertainty estimation model for this source category was developed by integrating the CH_4 and N_2O stationary source inventory estimation models with the model for CO_2 from fossil fuel combustion to realistically characterize the interaction (or endogenous correlation) between the variables of these three models. About 55 input variables were simulated for the uncertainty analysis of this source category (about 20 from the CO_2 emissions from fossil fuel combustion inventory estimation model and about 35 from the stationary source inventory models).

In developing the uncertainty estimation model, uniform distribution was assumed for all activity-related input variables and N_2O emission factors, based on the SAIC/EIA (2001) report.[117] For these variables, the uncertainty ranges were assigned to the input variables based on the data reported in SAIC/EIA (2001).[118] However, the CH_4 emission factors differ from those used by EIA. Since these factors were obtained from IPCC/UNEP/OECD/IEA (1997), uncertainty ranges were assigned based on IPCC default uncertainty estimates (IPCC 2000).

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[114] SAIC/EIA (2001) characterizes the underlying probability density function for the input variables as a combination of uniform and normal distributions (the former to represent the bias component and the latter to represent the random component). However, for purposes of the current uncertainty analysis, it was determined that uniform distribution was more appropriate to characterize the probability density function underlying each of these variables.

[115] In the SAIC/EIA (2001) report, the quantitative uncertainty estimates were developed for each of the three major fossil fuels used within each end-use sector; the variations within the sub-fuel types within each end-use sector were not modeled. However, for purposes of assigning uncertainty estimates to the sub-fuel type categories within each end-use sector in the current uncertainty analysis, SAIC/EIA (2001)-reported uncertainty estimates were extrapolated.

[116] Although, in general, random uncertainties are the main focus of statistical uncertainty analysis, when the uncertainty estimates are elicited from experts, their estimates include both random and systematic uncertainties. Hence, both these types of uncertainties are represented in this uncertainty analysis.

[117] SAIC/EIA (2001) characterizes the underlying probability density function for the input variables as a combination of uniform and normal distributions (the former distribution to represent the bias component and the latter to represent the random component). However, for purposes of the current uncertainty analysis, it was determined that uniform distribution was more appropriate to characterize the probability density function underlying each of these variables.

[118] In the SAIC/EIA (2001) report, the quantitative uncertainty estimates were developed for each of the three major fossil fuels used within each end-use sector; the variations within the sub-fuel types within each end-use sector were not modeled. However, for purposes of assigning uncertainty estimates to the sub-fuel type categories within each end-use sector in the current uncertainty analysis, SAIC/EIA (2001)-reported uncertainty estimates were extrapolated.

CH_4 and N_2O from Mobile Combustion

A quantitative uncertainty analysis was conducted for the mobile source sector using the IPCC-recommended Tier 2 uncertainty estimation methodology, Monte Carlo Stochastic Simulation technique, using @RISK software. The uncertainty analysis was performed on 2012 estimates of CH_4 and N_2O emissions, incorporating probability distribution functions associated with the major input variables. For the purposes of this analysis, the uncertainty was modeled for the following four major sets of input variables: (1) vehicle miles traveled (VMT) data, by on-road vehicle and fuel type and (2) emission factor data, by on-road vehicle, fuel, and control technology type, (3) fuel consumption, data, by non-road vehicle and equipment type, and (4) emission factor data, by non-road vehicle and equipment type.

Uncertainty analyses were not conducted for NO_x, CO, or NMVOC emissions. Emission factors for these gases have been extensively researched since emissions of these gases from motor vehicles are regulated in the United States, and the uncertainty in these emission estimates is believed to be relatively low. For more information, see Section 3.8. However, a much higher level of uncertainty is associated with CH_4 and N_2O emission factors due to limited emission test data, and because, unlike CO_2 emissions, the emission pathways of CH_4 and N_2O are highly complex.

Carbon Emitted from Non-Energy Uses of Fossil Fuels

An uncertainty analysis was conducted to quantify the uncertainty surrounding the estimates of emissions and storage factors from non-energy uses. This analysis, performed using @RISK software and the IPCC-recommended Tier 2 methodology (Monte Carlo Stochastic Simulation technique), provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. The results presented below provide the 95 percent confidence interval, the range of values within which emissions are likely to fall, for this source category.

As noted above, the non-energy use analysis is based on U.S.-specific storage factors for (1) feedstock materials (natural gas, LPG, pentanes plus, naphthas, other oils, still gas, special naphthas, and other industrial coal), (2) asphalt, (3) lubricants, and (4) waxes. For the remaining fuel types (the “other” category in Table 3-20 and Table 3-21 of the main Inventory document), the storage factors were taken directly from the *IPCC Guidelines for National Greenhouse Gas Inventories*, where available, and otherwise assumptions were made based on the potential fate of carbon in the respective NEU products. To characterize uncertainty, five separate analyses were conducted, corresponding to each of the five categories. In all cases, statistical analyses or expert judgments of uncertainty were not available directly from the information sources for all the activity variables; thus, uncertainty estimates were determined using assumptions based on source category knowledge.

Incineration of Waste

A Tier 2 Monte Carlo analysis was performed to determine the level of uncertainty surrounding the estimates of CO_2 emissions and N_2O emissions from the incineration of waste (given the very low emissions for CH_4, no uncertainty estimate was derived). IPCC Tier 2 analysis allows the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. Uncertainty estimates and distributions for waste generation variables (i.e., plastics, synthetic rubber, and textiles generation) were obtained through a conversation with one of the authors of the Municipal Solid Waste in the United States reports. Statistical analyses or expert judgments of uncertainty were not available directly from the information sources for the other variables; thus, uncertainty estimates for these variables were determined using assumptions based on source category knowledge and the known uncertainty estimates for the waste generation variables.

The uncertainties in the waste incineration emission estimates arise from both the assumptions applied to the data and from the quality of the data. Key factors include MSW incineration rate; fraction oxidized; missing data on waste composition; average C content of waste components; assumptions on the synthetic/biogenic C ratio; and combustion conditions affecting N_2O emissions. The highest levels of uncertainty surround the variables that are based on assumptions (e.g., percent of clothing and footwear composed of synthetic rubber); the lowest levels of uncertainty surround variables that were determined by quantitative measurements (e.g., combustion efficiency, C content of C black).

Coal Mining

A quantitative uncertainty analysis was conducted for the coal mining source category using the IPCC-recommended Tier 2 uncertainty estimation methodology. Because emission estimates from underground ventilation systems were based on actual measurement data, uncertainty is relatively low. A degree of imprecision was introduced because the measurements used were not continuous but rather an average of quarterly instantaneous readings.

Additionally, the measurement equipment used can be expected to have resulted in an average of 10 percent overestimation of annual CH_4 emissions (Mutmansky & Wang 2000).

Estimates of CH_4 recovered by degasification systems are relatively certain for utilized CH_4 because of the availability of gas sales information. In addition, many coal mine operators provided information on mined-through dates for pre-drainage wells. Many of the recovery estimates use data on wells within 100 feet of a mined area. However, uncertainty exists concerning the radius of influence of each well. The number of wells counted, and thus the avoided emissions, may vary if the drainage area is found to be larger or smaller than estimated. The 2012 GHGRP data (EPA 2013) used for determining CH_4 emissions from vented degasification wells are based on weekly measurements, an improvement over the previous year's estimates, thus lowering the uncertainty of that subsource.

Abandoned Underground Coal Mines

A quantitative uncertainty analysis was conducted to estimate the uncertainty surrounding the estimates of emissions from abandoned underground coal mines. The uncertainty analysis described below provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. The results provide the range within which, with 95 percent certainty, emissions from this source category are likely to fall.

As discussed above, the parameters for which values must be estimated for each mine in order to predict its decline curve are: 1) the coal's adsorption isotherm; 2) CH_4 flow capacity as expressed by permeability; and 3) pressure at abandonment. Because these parameters are not available for each mine, a methodological approach to estimating emissions was used that generates a probability distribution of potential outcomes based on the most likely value and the probable range of values for each parameter. The range of values is not meant to capture the extreme values, but rather values that represent the highest and lowest quartile of the cumulative probability density function of each parameter. Once the low, mid, and high values are selected, they are applied to a probability density function.

Petroleum Systems

A quantitative uncertainty analysis was conducted for previous Inventories to determine the level of uncertainty surrounding estimates of emissions from petroleum systems using the recommended methodology from IPCC. Performed using @RISK software and the IPCC-recommended Tier 2 methodology (Monte Carlo Simulation technique), this analysis provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. The IPCC guidance notes that in using this method, "some uncertainties that are not addressed by statistical means may exist, including those arising from omissions or double counting, or other conceptual errors, or from incomplete understanding of the processes that may lead to inaccuracies in estimates developed from models." As a result, the understanding of the uncertainty of emissions estimates for this category will evolve and will improve as the underlying methodologies and datasets improve.

Performed using @RISK software and the IPCC-recommended Tier 2 methodology (Monte Carlo Stochastic Simulation technique), the method employed provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. The results provide the range within which, with 95 percent certainty, emissions from this source category are likely to fall.

The detailed, bottom-up inventory analysis used to evaluate U.S. petroleum systems reduces the uncertainty related to the CH_4 emission estimates in comparison to a top-down approach. However, some uncertainty still remains. Emission factors and activity factors are based on a combination of measurements, equipment design data, engineering calculations and studies, surveys of selected facilities and statistical reporting. Statistical uncertainties arise from natural variation in measurements, equipment types, operational variability and survey and statistical methodologies. Published activity factors are not available every year for all 64 activities analyzed for petroleum systems; therefore, some are estimated. Because of the dominance of the seven major sources, which account for 92 percent of the total methane emissions, the uncertainty surrounding these seven sources has been estimated most rigorously, and serves as the basis for determining the overall uncertainty of petroleum systems emission estimates.

Natural Gas Systems

A quantitative uncertainty analysis was conducted for previous Inventories to determine the level of uncertainty surrounding estimates of emissions from natural gas systems using the recommended methodology from IPCC. Performed using @RISK software and the IPCC-recommended Tier 2 methodology (Monte Carlo Simulation technique), this analysis provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. The IPCC guidance notes that in using this method, "some uncertainties that are not addressed by statistical means may exist, including those arising from omissions or double counting, or other conceptual errors, or from incomplete understanding of the processes that may lead to inaccuracies in estimates developed from models." As a result, the understanding of the uncertainty of emissions estimates for this category will evolve and will improve as the underlying methodologies and datasets improve.

The @RISK model was used to quantify the uncertainty associated with the emissions estimates using the top twelve emission sources for the year 2009. The uncertainty analysis has not yet been updated for the 1990 through 2012 Inventory; instead, the uncertainty ranges calculated previously were applied to 2012 emissions estimates. The majority of sources in the current inventory were calculated using the same emission factors and activity data for which PDFs were developed in the 1990 through 2009 uncertainty analysis. Several emissions sources have been updated with the current Inventory, and the 2009 uncertainty ranges will not reflect the uncertainty associated with the recently updated emission factors and activity data sources. EPA plans to revise this uncertainty analysis.

International Bunker Fuels

Emission estimates related to the consumption of international bunker fuels are subject to the same uncertainties as those from domestic aviation and marine mobile combustion emissions; however, additional uncertainties result from the difficulty in collecting accurate fuel consumption activity data for international transport activities separate from domestic transport activities.[119] For example, smaller aircraft on shorter routes often carry sufficient fuel to complete several flight segments without refueling in order to minimize time spent at the airport gate or take advantage of lower fuel prices at particular airports. This practice, called tankering, when done on international flights, complicates the use of fuel sales data for estimating bunker fuel emissions. Tankering is less common with the type of large, long-range aircraft that make many international flights from the United States, however. Similar practices occur in the marine shipping industry where fuel costs represent a significant portion of overall operating costs and fuel prices vary from port to port, leading to some tankering from ports with low fuel costs.

Uncertainties exist with regard to the total fuel used by military aircraft and ships, and in the activity data on military operations and training that were used to estimate percentages of total fuel use reported as bunker fuel emissions. Total aircraft and ship fuel use estimates were developed from DoD records, which document fuel sold to the Navy and Air Force from the Defense Logistics Agency. These data may slightly over or under estimate actual total fuel use in aircraft and ships because each Service may have procured fuel from, and/or may have sold to, traded with, and/or given fuel to other ships, aircraft, governments, or other entities. There are uncertainties in aircraft operations and training activity data. Estimates for the quantity of fuel actually used in Navy and Air Force flying activities reported as bunker fuel emissions had to be estimated based on a combination of available data and expert judgment. Estimates of marine bunker fuel emissions were based on Navy vessel steaming hour data, which reports fuel used while underway and fuel used while not underway. This approach does not capture some voyages that would be classified as domestic for a commercial vessel. Conversely, emissions from fuel used while not underway preceding an international voyage are reported as domestic rather than international as would be done for a commercial vessel. There is uncertainty associated with ground fuel estimates for 1997 through 2001. Small fuel quantities may have been used in vehicles or equipment other than that which was assumed for each fuel type.

There are also uncertainties in fuel end-uses by fuel-type, emissions factors, fuel densities, diesel fuel sulfur content, aircraft and vessel engine characteristics and fuel efficiencies, and the methodology used to back-calculate the data set to 1990 using the original set from 1995. The data were adjusted for trends in fuel use based on a closely correlating, but not matching, data set. All assumptions used to develop the estimate were based on process knowledge, Department and military Service data, and expert judgments. The magnitude of the potential errors related to the various uncertainties has not been calculated, but is believed to be small. The uncertainties associated with future military bunker fuel emission estimates could be reduced through additional data collection.

Although aggregate fuel consumption data have been used to estimate emissions from aviation, the recommended method for estimating emissions of gases other than CO_2 in the 2006 IPCC Guidelines is to use data by specific aircraft type, number of individual flights and, ideally, movement data to better differentiate between domestic and international aviation and to facilitate estimating the effects of changes in technologies. The IPCC also recommends

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[119] See uncertainty discussions under Carbon Dioxide Emissions from Fossil Fuel Combustion.

that cruise altitude emissions be estimated separately using fuel consumption data, while landing and take-off (LTO) cycle data be used to estimate near-ground level emissions of gases other than CO_2.[120]

There is also concern regarding the reliability of the existing DOC (2011) data on marine vessel fuel consumption reported at U.S. customs stations due to the significant degree of inter-annual variation.

Wood Biomass and Ethanol Consumption

It is assumed that the combustion efficiency for woody biomass is 100 percent, which is believed to be an overestimate of the efficiency of wood combustion processes in the United States. Decreasing the combustion efficiency would decrease emission estimates. Additionally, the heat content applied to the consumption of woody biomass in the residential, commercial, and electric power sectors is unlikely to be a completely accurate representation of the heat content for all the different types of woody biomass consumed within these sectors. Emission estimates from ethanol production are more certain than estimates from woody biomass consumption due to better activity data collection methods and uniform combustion techniques.

Industrial Processes

The uncertainty analysis descriptions in this section correspond to source categories included in the Industrial Processes Chapter of the Inventory.

Cement Production

The uncertainties contained in these estimates are primarily due to uncertainties in the lime content of clinker and in the percentage of CKD recycled inside the cement kiln. Uncertainty is also associated with the assumption that all calcium-containing raw materials are $CaCO_3$, when a small percentage likely consists of other carbonate and non-carbonate raw materials. The lime content of clinker varies from 60 to 67 percent; 65 percent is used as a representative value (van Oss 2013a). CKD loss can range from 1.5 to 8 percent depending upon plant specifications. Additionally, some amount of CO_2 is reabsorbed when the cement is used for construction. As cement reacts with water, alkaline substances such as calcium hydroxide are formed. During this curing process, these compounds may react with CO_2 in the atmosphere to create calcium carbonate. This reaction only occurs in roughly the outer 0.2 inches of surface area. Because the amount of CO_2 reabsorbed is thought to be minimal, it was not estimated.

Lime Production

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

In addition, a portion of the CO_2 emitted during lime production will actually be reabsorbed when the lime is consumed, especially at captive lime production facilities. As noted above, lime has many different chemical, industrial, environmental, and construction applications. In many processes, CO_2 reacts with the lime to create calcium carbonate (e.g., water softening). Carbon dioxide reabsorption rates vary, however, depending on the application. For example, 100 percent of the lime used to produce precipitated calcium carbonate reacts with CO_2; whereas most of the lime used in steel making reacts with impurities such as silica, sulfur, and aluminum compounds. Quantifying the amount of CO_2 that is reabsorbed would require a detailed accounting of lime use in the United States and additional information about the associated processes where both the lime and byproduct CO_2 are "reused" are required to quantify the amount of CO_2 that

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

is reabsorbed. Research conducted thus far has not yielded the necessary information to quantify CO_2 reabsorbtion rates.[121]

In some cases, lime is generated from calcium carbonate byproducts at pulp mills and water treatment plants.[122] The lime generated by these processes is included in the USGS data for commercial lime consumption. In the pulping industry, mostly using the Kraft (sulfate) pulping process, lime is consumed in order to causticize a process liquor (green liquor) composed of sodium carbonate and sodium sulfide. The green liquor results from the dilution of the smelt created by combustion of the black liquor where biogenic C is present from the wood. Kraft mills recover the calcium carbonate "mud" after the causticizing operation and calcine it back into lime—thereby generating CO_2—for reuse in the pulping process. Although this re-generation of lime could be considered a lime manufacturing process, the CO_2 emitted during this process is mostly biogenic in origin, and therefore is not included in the industrial processes totals (Miner and Upton 2002). In accordance with IPCC methodological guidelines, any such emissions are calculated by accounting for net carbon (C) fluxes from changes in biogenic C reservoirs in wooded or crop lands (see Chapter 7).

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

Uncertainties also remain surrounding recovery rates used for sugar refining and PCC production. The recovery rate for sugar refineries is based on consultation with USGS commodity expert (Miller 2013) and two sugar beet processing and refining facilities located in California that use 100 percent recovered CO_2 from lime plants (Lutter 2009). This analysis assumes that all sugar refineries located on-site at lime plants also use 100 percent recovered CO_2. The recovery rate for PCC producers located on-site at lime plants is based on the 2012 value for PCC manufactured at commercial lime plants, given by USGS (Miller 2012). However, most PCC production occurs at non-commercial lime facilities, such as paper mills. Satellite PCC plants at paper mills tend to use CO_2 produced from the paper mill (potentially biomass based). This could introduce additional uncertainty in the CO_2 estimates, because CO_2 recovered from pulp and paper facilities is mostly biogenic in origin.

Another uncertainty is the assumption that calcination emissions for LKD are around 2 percent. The National Lime association has commented that the estimates of emissions from LKD in the US could be closer to 6 percent. In addition, they note emissions may also be generated through production of other byproducts/wastes at lime plants (Seeger 2013). There is limited data publicly available on LKD generation rates and also quantities, types of other byproducts/wastes produced at lime facilities. Further research is needed to improve understanding of additional calcination emissions to consider revising the current assumptions based on the IPCC Guidelines

Other Process Uses of Carbonates

The uncertainty levels presented in this section account for uncertainty associated with activity data. Data on limestone and dolomite consumption are collected by USGS through voluntary national surveys. USGS contacts the mines (i.e., producers of various types of crushed stone) for annual sales data. Data on other carbonate consumption are not readily available. The producers report the annual quantity sold to various end-users/industry types. USGS estimates the historical response rate for the crushed stone survey to be approximately 70 percent, the rest is estimated by USGS. Large fluctuations in reported consumption exist, reflecting year-to-year changes in the number of survey responders. The uncertainty resulting from a shifting survey population is exacerbated by the gaps in the time series of reports. The accuracy of distribution by end use is also uncertain because this value is reported by the producer/mines and not the end user. Additionally, there is significant inherent uncertainty associated with estimating withheld data points for specific end uses of limestone and dolomite. Lastly, much of the limestone consumed in the United States is reported as "other unspecified uses;" therefore, it is difficult to accurately allocate this unspecified quantity to the correct end-uses.

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[121] Representatives of the National Lime Association estimate that CO_2 reabsorption that occurs from the use of lime may offset as much as a quarter of the CO_2 emissions from calcination (Males 2003).

[122] Some carbide producers may also regenerate lime from their calcium hydroxide byproducts, which does not result in emissions of CO_2. In making calcium carbide, quicklime is mixed with coke and heated in electric furnaces. The regeneration of lime in this process is done using a waste calcium hydroxide (hydrated lime) [$CaC_2 + 2H_2O \rightarrow C_2H_2 + Ca(OH)_2$], not calcium carbonate [$CaCO_3$]. Thus, the calcium hydroxide is heated in the kiln to simply expel the water [$Ca(OH)_2 + heat \rightarrow CaO + H_2O$] and no CO_2 is released.

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

Soda Ash Production and Consumption

Emission estimates from soda ash production have relatively low associated uncertainty levels in that reliable and accurate data sources are available for the emission factor and activity data. Soda ash production data was collected by the USGS from voluntary surveys. A survey request was sent to each of the five soda ash producers, all of which responded, representing 100 percent of the total production data (USGS 2013). One source of uncertainty is the purity of the trona ore used for manufacturing soda ash. The emission factor used for this estimate assumes the ore is 100 percent pure, and likely overestimates the emissions from soda ash manufacture. The average water-soluble sodium carbonate-bicarbonate content for ore mined in Wyoming ranges from 85.5 to 93.8 percent (USGS 1995a).The primary source of uncertainty, however, results from the fact that emissions from soda ash consumption are dependent upon the type of processing employed by each end-use. Specific emission factors for each end-use are not available, so a Tier 1 default emission factor is used for all end uses. Therefore, there is uncertainty surrounding the emission factors from the consumption of soda ash.

Glass Production

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

The estimates below also account for uncertainty associated with activity data. Large fluctuations in reported consumption exist, reflecting year-to-year changes in the number of survey responders. The uncertainty resulting from a shifting survey population is exacerbated by the gaps in the time series of reports. The accuracy of distribution by end use is also uncertain because this value is reported by the manufacturer of the input carbonates (limestone, dolomite & soda ash) and not the end user. For 2012, there has been no reported consumption of dolomite for glass manufacturing. This data has been reported to USGS by dolomite manufacturers and not end-users (i.e., glass manufacturers). There is a high uncertainty associated with this estimate, as dolomite is a major raw material consumed in glass production. Additionally, there is significant inherent uncertainty associated with estimating withheld data points for specific end uses of limestone and dolomite. The uncertainty of the estimates for limestone and dolomite used in glass making is especially high; however, since glass making accounts for a small percent of consumption, its contribution to the overall emissions estimate is low. Lastly, much of the limestone consumed in the United States is reported as “other unspecified uses;” therefore, it is difficult to accurately allocate this unspecified quantity to the correct end-uses. Further research is needed into alternate and more complete sources of data on carbonate-based raw material consumption by the glass industry.

Ammonia Production

The uncertainties presented in this section are primarily due to how accurately the emission factor used represents an average across all ammonia plants using natural gas feedstock. Uncertainties are also associated with ammonia production estimates and the assumption that all ammonia production and subsequent urea production was from the same process—conventional catalytic reforming of natural gas feedstock, with the exception of one ammonia production plant located in Kansas that is manufacturing ammonia from petroleum coke feedstock. Uncertainty is also associated with the representativeness of the emission factor used for the petroleum coke-based ammonia process. It is also assumed that ammonia and urea are produced at collocated plants from the same natural gas raw material.

Recovery of CO_2 from ammonia production plants for purposes other than urea production (e.g., commercial sale, etc.) has not been considered in estimating the CO_2 emissions from ammonia production, as data concerning the disposition of recovered CO_2 are not available. Such recovery may or may not affect the overall estimate of CO_2 emissions depending upon the end use to which the recovered CO_2 is applied. Further research is required to determine whether byproduct CO_2 is being recovered from other ammonia production plants for application to end uses that are not accounted for elsewhere.

Urea Consumption for Non-Agricultural Purposes

There is limited publicly available data on the quantities of urea produced and consumed for non-agricultural purposes. Therefore, the amount of urea used for non-agricultural purposes is estimated based on a balance that relies on estimates of urea production, urea imports, urea exports, and the amount of urea used as fertilizer. The primary uncertainties associated with this source category are associated with the accuracy of these estimates as well as the fact that each estimate is obtained from a different data source. Because urea production estimates are no longer available from the USGS, there is additional uncertainty associated with urea produced beginning in 2011. There is also uncertainty associated with the assumption that all of the carbon in urea is released into the environment as CO_2 during use.

Nitric Acid Production

Uncertainty associated with the parameters used to estimate N_2O emissions includes that of production data, the share of U.S. nitric acid production attributable to each emission abatement technology over the time series, and the emission factors applied to each abatement technology type. While some information has been obtained through outreach with industry associations, limited information is available over the time series for a variety of facility level variables, including plant specific production levels, plant production technology (e.g., low, high pressure, etc.) and abatement technology type, installation date of abatement technology, and accurate destruction and removal efficiency rates.

Adipic Acid Production

Uncertainty associated with N_2O emission estimates included that of the methods used by companies to monitor and estimate emissions.

Silicon Carbide Production and Consumption

There is uncertainty associated with the emission factors used because they are based on stoichiometry as opposed to monitoring of actual SiC production plants. An alternative would be to calculate emissions based on the quantity of petroleum coke used during the production process rather than on the amount of silicon carbide produced. However, these data were not available. For CH_4, there is also uncertainty associated with the hydrogen-containing volatile compounds in the petroleum coke (IPCC 2006). There is also uncertainty associated with the use or destruction of methane generated from the process in addition to uncertainty associated with levels of production, net imports, consumption levels, and the percent of total consumption that is attributed to metallurgical and other non-abrasive uses.

Petrochemical Production

The CH_4 emission factors used for petrochemical production are based on a limited number of studies. Using plant-specific factors instead of default or average factors could increase the accuracy of the emission estimates; however, such data were not available for the current publication. There may also be other significant sources of CH_4 arising from petrochemical production activities that have not been included in these estimates.

The results of the quantitative uncertainty analysis for the CO_2 emissions from carbon black production calculation are based on feedstock consumption, import and export data, and carbon black production data. The composition of carbon black feedstock varies depending upon the specific refinery production process, and therefore the assumption that carbon black feedstock is 90 percent C gives rise to uncertainty. Also, no data are available concerning the consumption of coal-derived carbon black feedstock, so CO_2 emissions from the utilization of coal-based feedstock are not included in the emission estimate. In addition, other data sources indicate that the amount of petroleum-based feedstock used in carbon black production may be underreported by the U.S. Census Bureau. Finally, the amount of carbon black produced from the acetylene black, thermal black, and lamp black processes, although estimated to be a small percentage of the total production, is not known. Therefore, there is some uncertainty associated with the assumption that all of the carbon black is produced using the furnace black process.

Titanium Dioxide Production

Each year, USGS collects titanium industry data for titanium mineral and pigment production operations. If TiO_2 pigment plants do not respond, production from the operations is estimated on the basis of prior year production levels and industry trends. Variability in response rates varies from 67 to 100 percent of TiO_2 pigment plants over the time series. Although some TiO_2 may be produced using graphite or other carbon inputs, information and data regarding these practices were not available. Titanium dioxide produced using graphite inputs, for example, may generate differing amounts of CO_2 per unit of TiO_2 produced as compared to that generated through the use of petroleum coke in production. While the most accurate method to estimate emissions would be to base calculations on the amount of reducing agent used in each process rather than on the amount of TiO_2 produced, sufficient data were not available to do so.

As of 2004, the last remaining sulfate-process plant in the United States closed. Since annual TiO_2 production was not reported by USGS by the type of production process used (chloride or sulfate) prior to 2004 and only the percentage of total production capacity by process was reported, the percent of total TiO_2 production capacity that was attributed to the chloride process was multiplied by total TiO_2 production to estimate the amount of TiO_2 produced using the chloride process. Finally, the emission factor was applied uniformly to all chloride-process production, and no data were available to account for differences in production efficiency among chloride-process plants. In calculating the amount of petroleum coke consumed in chloride-process TiO_2 production, literature data were used for petroleum coke composition. Certain grades of petroleum coke are manufactured specifically for use in the TiO_2 chloride process; however, this composition information was not available.

Carbon Dioxide Production

Uncertainty is associated with the number of facilities that are currently producing CO_2 from naturally occurring CO_2 reservoirs for commercial uses other than EOR, and for which the CO_2 emissions are not accounted for elsewhere. Research indicates that there are only two such facilities, which are in New Mexico and Mississippi; however, additional facilities may exist that have not been identified. In addition, it is possible that CO_2 recovery exists in particular production and end-use sectors that are not accounted for elsewhere. Such recovery may or may not affect the overall estimate of CO_2 emissions from that sector depending upon the end use to which the recovered CO_2 is applied. Further research is required to determine whether CO_2 is being recovered from other facilities for application to end uses that are not accounted for elsewhere.

Phosphoric Acid Production

Phosphate rock production data used in the emission calculations were developed by the USGS through monthly and semiannual voluntary surveys of the active phosphate rock mines during 2012. For previous years in the time series, USGS provided the data disaggregated regionally; however, beginning in 2006, only total U.S. phosphate rock production was reported. Regional production for 2012 was estimated based on regional production data from previous years and multiplied by regionally-specific emission factors. There is uncertainty associated with the degree to which the estimated 2012 regional production data represents actual production in those regions. Total U.S. phosphate rock production data are not considered to be a significant source of uncertainty because all the domestic phosphate rock producers report their annual production to the USGS. Data for exports of phosphate rock used in the emission calculation are reported by phosphate rock producers and are not considered to be a significant source of uncertainty. Data for imports for consumption are based on international trade data collected by the U.S. Census Bureau. These U.S. government economic data are not considered to be a significant source of uncertainty.

An additional source of uncertainty in the calculation of CO_2 emissions from phosphoric acid production is the carbonate composition of phosphate rock, the composition of phosphate rock varies depending upon where the material is mined, and may also vary over time. The inventory relies on one study (FIPR 2003) of chemical composition of the phosphate rock; limited data is available beyond this study. Another source of uncertainty is the disposition of the organic carbon content of the phosphate rock. A representative of the FIPR indicated that in the phosphoric acid production process, the organic carbon content of the mined phosphate rock generally remains in the phosphoric acid product, which is what produces the color of the phosphoric acid product (FIPR 2003a). Organic carbon is therefore not included in the calculation of CO_2 emissions from phosphoric acid production.

A third source of uncertainty is the assumption that all domestically-produced phosphate rock is used in phosphoric acid production and used without first being calcined. Calcination of the phosphate rock would result in conversion of some of the organic carbon in the phosphate rock into CO_2. However, according to air permit information available to the public, at least one facility has calcining units permitted for operation (NCDENR 2013).

Finally, USGS indicated that approximately 7 percent of domestically-produced phosphate rock is used to manufacture elemental phosphorus and other phosphorus-based chemicals, rather than phosphoric acid (USGS 2006). According to USGS, there is only one domestic producer of elemental phosphorus, in Idaho, and no data were available concerning the annual production of this single producer. Elemental phosphorus is produced by reducing phosphate rock with coal coke, and it is therefore assumed that 100 percent of the carbonate content of the phosphate rock will be converted to CO_2 in the elemental phosphorus production process. The calculation for CO_2 emissions is based on the assumption that phosphate rock consumption, for purposes other than phosphoric acid production, results in CO_2 emissions from 100 percent of the inorganic carbon content in phosphate rock, but none from the organic carbon content.

Iron and Steel Production and Metallurgical Coke Production

The estimates of CO_2 and CH_4 emissions from metallurgical coke production are based on material production and consumption data and average carbon contents. Uncertainty is associated with the total U.S. coking coal consumption, total U.S. coke production and materials consumed during this process. Data for coking coal consumption and metallurgical coke production are from different data sources (EIA) than data for other carbonaceous materials consumed at coke plants (AISI), which does not include data for merchant coke plants. There is uncertainty associated with the fact that coal tar and coke breeze production were estimated based on coke production because coal tar and coke breeze production data were not available. Since merchant coke plant data is not included in the estimate of other carbonaceous materials consumed at coke plants, the mass balance equation for CO_2 from metallurgical coke production cannot be reasonably completed. Therefore, for the purpose of this analysis, uncertainty parameters are applied to primary data inputs to the calculation (i.e, coking coal consumption and metallurgical coke production) only.

The estimates of CO_2 emissions from iron and steel production are based on material production and consumption data and average carbon contents. There is uncertainty associated with the assumption that direct reduced iron and sinter consumption are equal to production. There is uncertainty associated with the assumption that all coal used for purposes other than coking coal is for direct injection coal; some of this coal may be used for electricity generation. There is also uncertainty associated with the carbon contents for pellets, sinter, and natural ore, which are assumed to equal the carbon contents of direct reduced iron. For EAF steel production, there is uncertainty associated with the amount of EAF anode and charge carbon consumed due to inconsistent data throughout the time series. Also for EAF steel production, there is uncertainty associated with the assumption that 100 percent of the natural gas attributed to "steelmaking furnaces" by AISI is process-related and nothing is combusted for energy purposes. Uncertainty is also associated with the use of process gases such as blast furnace gas and coke oven gas. Data are not available to differentiate between the use of these gases for processes at the steel mill versus for energy generation (i.e., electricity and steam generation); therefore, all consumption is attributed to iron and steel production. These data and carbon contents produce a relatively accurate estimate of CO_2 emissions. However, there are uncertainties associated with each.

For the purposes of the CH_4 calculation from iron and steel production it is assumed that all of the CH_4 escapes as fugitive emissions and that none of the CH_4 is captured in stacks or vents. Additionally, the CO_2 emissions calculation is not corrected by subtracting the carbon content of the CH_4, which means there may be a slight double counting of carbon as both CO_2 and CH_4.

Ferroalloy Production

Annual ferroalloy production is currently reported by the USGS in three broad categories: ferroalloys containing 25 to 55 percent silicon (including miscellaneous alloys), ferroalloys containing 56 to 95 percent silicon, and silicon metal (through 2005 only). Silicon metal production values for 2006 through 2012 are assumed to be equal to the 2005 value reported by USGS (USGS did not report silicon metal production for 2006 through 2012). Ferrosilicon production values for 2011 and 2012 are assumed to be equal to the 2010 value reported by USGS (USGS did not report ferrosilicon production for 2011 and 2012). It was assumed that the IPCC emission factors apply to all of the ferroalloy production processes, including miscellaneous alloys. Finally, production data for silvery pig iron (alloys containing less than 25 percent silicon) are not reported by the USGS to avoid disclosing proprietary company data. Emissions from this production category, therefore, were not estimated.

Also, some ferroalloys may be produced using wood or other biomass as a primary or secondary carbon source (carbonaceous reductants), information and data regarding these practices were not available. Emissions from ferroalloys produced with wood or other biomass would not be counted under this source because wood-based carbon is of biogenic origin.[123] Even though emissions from ferroalloys produced with coking coal or graphite inputs would be counted in national trends, they may be generated with varying amounts of CO_2 per unit of ferroalloy produced. The most accurate method for these estimates would be to base calculations on the amount of reducing agent used in the process, rather than the amount of ferroalloys produced. These data, however, were not available, and are also often considered confidential business information.

Emissions of CH_4 from ferroalloy production will vary depending on furnace specifics, such as type, operation technique, and control technology. Higher heating temperatures and techniques such as sprinkle charging will reduce CH_4 emissions; however, specific furnace information was not available or included in the CH_4 emission estimates.

Aluminum Production

Uncertainty was assigned to the CO_2, CF_4, and C_2F_6 emission values reported by each individual facility to EPA's GHGRP. As previously mentioned, the methods for estimating emissions for EPA's GHGRP and this report are the same, and follow the IPCC (2006) methodology. As a result, it was possible to assign uncertainty bounds (and

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

distributions) based on an analysis of the uncertainty associated with the facility-specific emissions estimated for previous inventory years. Uncertainty surrounding the reported CO_2, CF_4, and C_2F_6 emission values were determined to have a normal distribution with uncertainty ranges of ±6, ±16, and ±20 percent, respectively. A Monte Carlo analysis was applied to estimate the overall uncertainty of the CO_2, CF_4, and C_2F_6 emission estimates for the U.S. aluminum industry as a whole, and the results are provided below.

Magnesium Production

To estimate the uncertainty surrounding the estimated 2012 SF_6 emissions from magnesium production and processing, the uncertainties associated with three variables were estimated: (1) emissions reported by magnesium producers and processors for 2012 through EPA's GHGRP, (2) emissions estimated for magnesium producers and processors that reported via the Partnership in prior years but did not report 2012 emissions through EPA's GHGRP, and (3) emissions estimated for magnesium producers and processors that did not participate in the Partnership or report through EPA's GHGRP. An uncertainty of 5 percent was assigned to the SF_6 emissions (usage) data reported by each GHGRP reporter (per the 2006 IPCC Guidelines). If facilities did not report emissions data during the current reporting year through EPA's GHGRP reporting program, SF_6 emissions data were held constant at the most recent available value reported through the Partnership. The uncertainty associated with these values was estimated to be 30 percent for each year of extrapolation. One known sand caster (the lone Partner) has not reported since 2007 and its activity and emission factor were held constant at 2005 levels due to a reporting anomaly in 2006 because of malfunctions at the facility. The uncertainty associated with the SF_6 usage for the sand casting Partner was 74 percent. For those industry processes that are not represented in Partnership, such as permanent mold and wrought casting, SF_6 emissions were estimated using production and consumption statistics reported by USGS and estimated process-specific emission factors (see Table 4-81 in the main Inventory document). The uncertainties associated with the emission factors and USGS-reported statistics were assumed to be 75 percent and 25 percent, respectively. Emissions associated with die casting and sand casting activities utilized emission factors based on Partner reported data with an uncertainties of 75 percent. In general, where precise quantitative information was not available on the uncertainty of a parameter, a conservative (upper-bound) value was used.

Additional uncertainties exist in these estimates that are not addressed in this methodology, such as the basic assumption that SF_6 neither reacts nor decomposes during use. The melt surface reactions and high temperatures associated with molten magnesium could potentially cause some gas degradation. Previous measurement studies have identified SF_6 cover gas degradation in die casting applications on the order of 20 percent (Bartos et al. 2007). Sulfur hexafluoride may also be used as a cover gas for the casting of molten aluminum with high magnesium content; however, the extent to which this technique is used in the United States is unknown.

Zinc Production

The uncertainties contained in these estimates are two-fold, relating to activity data and emission factors used. First, there is uncertainty associated with the amount of EAF dust consumed in the United States to produce secondary zinc using emission-intensive Waelz kilns. The estimate for the total amount of EAF dust consumed in Waelz kilns is based on (1) an EAF dust consumption value reported annually by Horsehead Corporation as part of its financial reporting to the Securities and Exchange Commission (SEC), and (2) an EAF dust consumption value obtained from the Waelz kiln facility operated in Alabama by Steel Dust Recycling LLC. Since actual EAF dust consumption information is not available for PIZO's facility (2009-2010) and SDR's facility (2008-2010), the amount is estimated by multiplying the EAF dust recycling capacity of the facility (available from the company's Web site) by the capacity utilization factor for Horsehead Corporation (which is available from Horsehead's financial reports). Also, the EAF dust consumption for PIZO's facility in 2011 was estimated by multiplying the average capacity utilization factor developed from Horsehead Corp. and SDR's annual capacity utilization rates by PIZO's EAF dust recycling capacity. Therefore, there is uncertainty associated with the assumption used to estimate PIZO and SDR's annual EAF dust consumption values (except SDR's EAF dust consumption in 2011 which was obtained from SDR's recycling facility in Alabama).

Second, there are uncertainties associated with the emission factors used to estimate CO_2 emissions from secondary zinc production processes. The Waelz kiln emission factors are based on materials balances for metallurgical coke and EAF dust consumed as provided by Viklund-White (2000). Therefore, the accuracy of these emission factors depend upon the accuracy of these materials balances. Data limitations prevented the development of emission factors for the electrothermic process. Therefore, emission factors for the Waelz kiln process were applied to both electrothermic and Waelz kiln production processes.

Lead Production

Uncertainty associated with lead production relates to the emission factors and activity data used. The direct smelting emission factor used in primary production is taken from Sjardin (2003) who averaged the values provided by three other studies (Dutrizac et al. 2000, Morris et al. 1983, Ullman 1997). For secondary production, Sjardin (2003) added a CO_2 emission factor associated with battery treatment. The applicability of these emission factors to plants in the United States is uncertain. There is also a smaller level of uncertainty associated with the accuracy of primary and secondary production data provided by the USGS.

HCFC-22 Production

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

The relative errors yielded by the Monte Carlo Stochastic Simulation for 2006 were applied to the U.S. emission estimate for 2012. The resulting estimates of absolute uncertainty are likely to be reasonably accurate because (1) the methods used by the three plants to estimate their emissions are not believed to have changed significantly since 2006, and (2) although the distribution of emissions among the plants may have changed between 2006 and 2012 (because both HCFC-22 production and the HFC-23 emission rate declined significantly), the two plants that contribute significantly to emissions were estimated to have similar relative uncertainties in their 2006 (as well as 2005) emission estimates. Thus, changes in the relative contributions of these two plants to total emissions are not likely to have a large impact on the uncertainty of the national emission estimate.

Substitution of Ozone Depleting Substances

Given that emissions of ODS substitutes occur from thousands of different kinds of equipment and from millions of point and mobile sources throughout the United States, emission estimates must be made using analytical tools such as the Vintaging Model or the methods outlined in IPCC (2006). Though the model is more comprehensive than the IPCC default methodology, significant uncertainties still exist with regard to the levels of equipment sales, equipment characteristics, and end-use emissions profiles that were used to estimate annual emissions for the various compounds.

The Vintaging Model estimates emissions from 60 end-uses. The uncertainty analysis, however, quantifies the level of uncertainty associated with the aggregate emissions resulting from the top 21 end-uses, comprising over 95 percent of the total emissions, and 6 other end-uses. These 27 end-uses comprise 97 percent of the total emissions, equivalent to 143.6 Tg CO_2 Eq. In an effort to improve the uncertainty analysis, additional end-uses are added annually, with the intention that over time uncertainty for all emissions from the Vintaging Model will be fully characterized. Any end-uses included in previous years' uncertainty analysis were included in the current uncertainty analysis, whether or not those end-uses were included in the top 95 percent of emissions from ODS Substitutes.

In order to calculate uncertainty, functional forms were developed to simplify some of the complex "vintaging" aspects of some end-use sectors, especially with respect to refrigeration and air-conditioning, and to a lesser degree, fire extinguishing. These sectors calculate emissions based on the entire lifetime of equipment, not just equipment put into commission in the current year, thereby necessitating simplifying equations. The functional forms used variables that included growth rates, emission factors, transition from ODSs, change in charge size as a result of the transition, disposal quantities, disposal emission rates, and either stock for the current year or original ODS consumption. Uncertainty was estimated around each variable within the functional forms based on expert judgment, and a Monte Carlo analysis was performed. The most significant sources of uncertainty for this source category include the emission factors for refrigerated transport, as well as the percent of non-MDI aerosol propellant that is HFC-152a.

Semiconductor Manufacture

A quantitative uncertainty analysis of this source category was performed using the IPCC-recommended Tier 2 uncertainty estimation methodology, the Monte Carlo Stochastic Simulation technique. The equation used to estimate uncertainty is:

$$\text{Total Emissions } (E_T) = \text{GHGRP Reported Emissions } (E_R) + \text{Non-GHGRP Reporters Emissions } (E_{NR})$$

where E_R and E_{NR} denote totals for the indicated subcategories of emissions.

The uncertainty in E_T presented in Table 4-97 in the main Inventory document below results from the convolution of two distributions of emissions, each reflecting separate estimates of possible values of E_R and E_{NR}. The approach and methods for estimating each distribution and combining them to arrive at the reported 95 percent CI are described in the remainder of this section.

The uncertainty estimate of E_R, or GHGRP reported emissions, is developed based on gas-specific uncertainty estimates of emissions for two representative model facilities, one processing 200 mm wafers and one processing 300 mm wafers. Uncertainties in emissions for each gas and model facility were developed during the assessment of emission estimation methods for the subpart I GHGRP rulemaking in 2012 (see *Technical Support for Modifications to the Fluorinated Greenhouse Gas Emission Estimation Method Option for Semiconductor Facilities under Subpart* I, docket EPA–HQ–OAR–2011–0028).[124] This analysis did not take into account the use of abatement. For the model facility that processed 200 mm wafers, estimates of uncertainties at a 95 percent CI ranged from ±29 percent for C_3F_8 to ±10 percent for CF_4. For the corresponding model 300 mm facility, estimates of the 95 percent CI ranged from ±36 percent for C_4F_8 to ±16 percent for CF_4. These gas and wafer-specific uncertainty estimates are applied for facilities that did not abate emissions as reported under EPA's GHGRP.

For those facilities reporting abatement of emissions under EPA's GHGRP, estimates of uncertainties for the no abatement model facilities are modified to reflect the use of full abatement (abatement of *all* gases from *all* cleaning and etching equipment) and partial abatement. These assumptions used to develop uncertainties for the partial and full abatement facilities are identical for 200 mm and 300 mm wafer processing facilities. For all facilities reporting gas abatement, a triangular distribution of destruction or removal efficiency is assumed for each gas. For facilities reporting partial abatement, the distribution of destruction efficiencies, for each gas, is assumed to be right triangularly distributed. Consideration of abatement then resulted in four additional model facilities, two (model) 200 mm wafer-processing facilities (one fully and one partially abating each gas) and two (model) 300 mm wafer-processing facilities (one fully and the other partially abating each gas). Gas-specific emission uncertainties were estimated by convolving the distributions of unabated emissions with the appropriate distribution of abatement efficiency for fully and partially abated facilities using a Montel Carlo simulation.

The uncertainty in E_R is obtained by mapping GHGRP-reported gas and wafer-specific emissions to one of the six described model facilities, and then running a Monte Carlo simulation which results in the 95 percent CI for GHGRP reporting facilities (E_R).

The estimate of uncertainty in E_{NR} entailed developing estimates of uncertainties for the emissions factors for each non-reporting sub-category and the corresponding estimates of TMLA.

The uncertainty in TMLA depends on the uncertainty of two variables – an estimate of the uncertainty in the average annual capacity utilization for each level of production of fabs (e.g., full scale or R&D production) and a corresponding estimate of the uncertainty in the number of layers manufactured. For both variables, the distributions of capacity utilizations and number of manufactured layers are assumed triangular for all categories of non-reporting fabs. For production fabs the most probable utilization is assumed to be 89 percent, with the highest and lowest utilization assumed to be 95 percent and 70 percent, respectively. The corresponding values for facilities that manufacture discrete devices are, 84 percent, 95 percent, and 73 percent, respectively, while the values for utilization for R&D facilities, are assumed to be 20 percent, 30 percent, and 10 percent, respectively. For the triangular distributions that govern the number of possible layers manufactured, it is assumed the most probable value is one layer less than reported in the ITRS; the

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[124] On November 13, 2013, EPA published a final rule revising subpart I (Electronics Manufacturing) of the GHGRP (78 FR 68162). The revised rule includes updated default emission factors and updated default destruction and removal efficiencies that are slightly different from those that semiconductor manufacturers were required to use to report their 2012 emissions. The uncertainty analyses that were performed during the development of the revised rule focused on these updated defaults, but are expected to be reasonably representative of the uncertainties associated with the older defaults, particularly for estimates at the country level. (They may somewhat underestimate the uncertainties associated with the older defaults at the facility level.) For simplicity, the 2012 estimates are assumed to be unbiased although in some cases, the updated (and therefore more representative) defaults are higher or lower than the older defaults. Multiple models and sensitivity scenarios were run for the subpart I analysis. The uncertainty analysis presented here made use of the Input gas and wafer size model (Model 1) under the following conditions: Year = 2010, f = 20, n = SIA3.

smallest number varied by technology generation between one and two layers less than given in the ITRS and largest number of layers corresponded to the figure given in the ITRS.

The uncertainty bounds for the average capacity utilization and the number of layers manufactured are used as inputs in a separate Monte Carlo simulation to estimate the uncertainty around the TMLA of both individual facilities as well as the total non-reporting TMLA of each sub-population.

The uncertainty around the emission factors for each non-reporting category of facilities is dependent on the uncertainty of the total emissions (MMTCO$_2$e units) and the TMLA of each reporting facility in that category. For each subpopulation of reporting facilities, total emissions were regressed on TMLA (with an intercept forced to zero) for 10,000 emissions and 10,000 TMLA values in a Monte Carlo simulation, which results in 10,000 total regression coefficients (emission factors). The 2.5th and the 97.5th percentile of these emission factors are determined and the bounds are assigned as the percent difference from the estimated emission factor.

For simplicity, the results of the Monte Carlo simulations on the bounds of the gas- and wafer size-specific emissions as well as the TMLA and emission factors are assumed to be normally distributed and the uncertainty bounds are assigned at 1.96 standard deviations around the estimated mean. The departures from normality were observed to be small.

The final step in estimating the uncertainty in emissions of non-reporting facilities is convolving the distribution of emission factors with the distribution of TMLA using Monte Carlo simulation.

Electrical Transmission and Distribution

To estimate the uncertainty associated with emissions of SF$_6$ from Electrical Transmission and Distribution, uncertainties associated with four quantities were estimated: (1) emissions from Partners, (2) emissions from GHGRP-Only Reporters, (3) emissions from Non-Reporters, and (4) emissions from manufacturers of electrical equipment. A Monte Carlo analysis was then applied to estimate the overall uncertainty of the emissions estimate.

Total emissions from the SF$_6$ Emission Reduction Partnership include emissions from both reporting (through the Partnership or GHGRP) and non-reporting Partners. For reporting Partners, individual Partner-reported SF$_6$ data was assumed to have an uncertainty of 10 percent. Based on a Monte Carlo analysis, the cumulative uncertainty of all Partner-reported data was estimated to be 2.5 percent. The uncertainty associated with extrapolated or interpolated emissions from non-reporting Partners was assumed to be 20 percent.

For GHGRP-Only Reporters, reported SF$_6$ data was assumed to have an uncertainty of 20 percent.[125] Based on a Monte Carlo analysis, the cumulative uncertainty of all GHGRP-Only reported data was estimated to be 5.2 percent.

There are two sources of uncertainty associated with the regression equations used to estimate emissions in 2012 from Non-Reporters: (1) uncertainty in the coefficients (as defined by the regression standard error estimate), and (2) the uncertainty in total transmission miles for Non-Reporters. Uncertainties were also estimated regarding (1) the quantity of SF$_6$ supplied with equipment by equipment manufacturers, which is projected from Partner provided nameplate capacity data and industry SF$_6$ nameplate capacity estimates, and (2) the manufacturers' SF$_6$ emissions rate.

Solvent and Other Product Use

The uncertainty analysis descriptions in this section correspond to source categories included in the Solvent and Other Product Use Chapter of the Inventory.

Nitrous Oxide from Product Uses

The overall uncertainty associated with the 2012 N$_2$O emission estimate from N$_2$O product usage was calculated using the IPCC Guidelines for National Greenhouse Gas Inventories (2006) Tier 2 methodology. Uncertainty associated with the parameters used to estimate N$_2$O emissions include production data, total market share of each end use, and the emission factors applied to each end use, respectively.

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[125] Uncertainty is assumed to be higher for the GHGRP-Only category, because 2011 is the first year that those utilities have reported to EPA.

Agriculture

The uncertainty analysis descriptions in this section correspond to some source categories included in the Agriculture Chapter of the Inventory.

Enteric Fermentation

A quantitative uncertainty analysis for this source category was performed using the IPCC-recommended Tier 2 uncertainty estimation methodology based on a Monte Carlo Stochastic Simulation technique as described in ICF (2003). These uncertainty estimates were developed for the 1990 through 2001 Inventory report (i.e., 2003 submission to the UNFCCC). There have been no significant changes to the methodology since that time; consequently, these uncertainty estimates were directly applied to the 2012 emission estimates in this report.

A total of 185 primary input variables (177 for cattle and 8 for non-cattle) were identified as key input variables for the uncertainty analysis. A normal distribution was assumed for almost all activity- and emission factor-related input variables. Triangular distributions were assigned to three input variables (specifically, cow-birth ratios for the three most recent years included in the 2001 model run) to ensure only positive values would be simulated. For some key input variables, the uncertainty ranges around their estimates (used for inventory estimation) were collected from published documents and other public sources; others were based on expert opinion and best estimates. In addition, both endogenous and exogenous correlations between selected primary input variables were modeled. The exogenous correlation coefficients between the probability distributions of selected activity-related variables were developed through expert judgment.

Manure Management

An analysis (ERG 2003a) was conducted for the manure management emission estimates presented in the 1990 through 2001 Inventory report (i.e., 2003 submission to the UNFCCC) to determine the uncertainty associated with estimating CH_4 and N_2O emissions from livestock manure management. The quantitative uncertainty analysis for this source category was performed in 2002 through the IPCC-recommended Tier 2 uncertainty estimation methodology, the Monte Carlo Stochastic Simulation technique. The uncertainty analysis was developed based on the methods used to estimate CH_4 and N_2O emissions from manure management systems. A normal probability distribution was assumed for each source data category. The series of equations used were condensed into a single equation for each animal type and state. The equations for each animal group contained four to five variables around which the uncertainty analysis was performed for each state. These uncertainty estimates were directly applied to the 2012 emission estimates as there have not been significant changes in the methodology since that time.

Rice Cultivation

The largest uncertainty in the calculation of CH_4 emissions from rice cultivation is associated with the emission factors. Seasonal emissions, derived from field measurements in the United States, vary by more than one order of magnitude. This inherent variability is due to differences in cultivation practices, particularly fertilizer type, amount, and mode of application; differences in cultivar type; and differences in soil and climatic conditions. A portion of this variability is accounted for by separating primary from ratooned areas. However, even within a cropping season or a given management regime, measured emissions may vary significantly. Of the experiments used to derive the emission factors applied here, primary emissions ranged from 61 to 500 kg CH_4/hectare-season and ratoon emissions ranged from 481 to 1,490 kg CH_4/hectare-season. The uncertainty distributions around the California winter flooding, California non-winter flooding, non-California primary, and ratoon emission factors were derived using the distributions of the relevant emission factors available in the literature and described above. Variability around the rice emission factor means was not normally distributed for any crops, but rather skewed, with a tail trailing to the right of the mean. A lognormal statistical distribution was, therefore, applied in the Tier 2 Monte Carlo analysis.

Other sources of uncertainty include the primary rice-cropped area for each state, percent of rice-cropped area that is ratooned, the length of the growing season, and the extent to which flooding outside of the normal rice season is practiced. Expert judgment was used to estimate the uncertainty associated with primary rice-cropped area for each state at 1 to 5 percent, and a normal distribution was assumed. Uncertainties were applied to ratooned area by state, based on the level of reporting performed by the state. Within California, the uncertainty associated with the percentage of rice fields that are winter flooded was estimated at plus and minus 20 percent. No uncertainty estimates were calculated for the practice of flooding outside of the normal rice season outside of California because CH_4 flux measurements have not been undertaken over a sufficient geographic range or under a broad enough range of representative conditions to account for this source in the emission estimates or its associated uncertainty.

Agricultural Soil Management

Uncertainty was estimated for each of the following five components of N_2O emissions from agricultural soil management: (1) direct emissions simulated by DAYCENT; (2) the components of indirect emissions (N volatilized and leached or runoff) simulated by DAYCENT; (3) direct emissions approximated with the IPCC (2006) Tier 1 method; (4) the components of indirect emissions (N volatilized and leached or runoff) approximated with the IPCC (2006) Tier 1 method; and (5) indirect emissions estimated with the IPCC (2006) Tier 1 method. Uncertainty in direct emissions, which account for the majority of N_2O emissions from agricultural management, as well as the components of indirect emissions calculated by DAYCENT were estimated with a Monte Carlo Analysis, addressing uncertainties in model inputs and structure (i.e., algorithms and parameterization) (Del Grosso et al. 2010). Uncertainties in direct emissions calculated with the IPCC (2006) Tier 1 method, the proportion of volatilization and leaching or runoff estimated with the IPCC (2006) Tier 1 method, and indirect N_2O emissions were estimated with a simple error propagation approach (IPCC 2006). Uncertainties from the Tier 1 and Tier 3 (i.e., DAYCENT) estimates were combined using simple error propagation (IPCC 2006). Additional details on the uncertainty methods are provided in Annex 3.11.

Field Burning of Agricultural Residues

Due to data and time limitations, uncertainty resulting from burning of Kentucky bluegrass and “other” residues are not included in the emissions estimates and not incorporated into the uncertainty analysis.

Land Use, Land-Use Change, and Forestry

The uncertainty analysis descriptions in this section correspond to source categories included in the Land Use, Land-Use Change, and Forestry Chapter of the Inventory.

Forest Land Remaining Forest Land

The uncertainty analysis descriptions in this section correspond to source categories included in the Forest Land Remaining Forest Land sub-chapter of Land Use, Land-Use Change, and Forestry Chapter of the Inventory.

Changes in Forest Carbon Stocks

A quantitative uncertainty analysis placed bounds on current flux for forest ecosystems as well as C in harvested wood products through Monte Carlo Stochastic Simulation of the Methods described above and probabilistic sampling of C conversion factors and inventory data. See Annex 3.13 for additional information.

Non-CO_2 Emissions from Forest Fires

Non-CO_2 gases emitted from forest fires depend on several variables, including: forest area for Alaska and the lower 48 states; average C densities for wildfires in Alaska, wildfires in the lower 48 states, and prescribed fires in the lower 48 states; emission ratios; and combustion factor values (proportion of biomass consumed by fire). To quantify the uncertainties for emissions from forest fires, a Monte Carlo (Tier 2) uncertainty analysis was performed using information about the uncertainty surrounding each of these variables.

Direct N_2O fluxes from Forest Soils

The amount of N_2O emitted from forests depends not only on N inputs and fertilized area, but also on a large number of variables, including organic C availability, oxygen gas partial pressure, soil moisture content, pH, temperature, and tree planting/harvesting cycles. The effect of the combined interaction of these variables on N_2O flux is complex and highly uncertain. IPCC (2006) does not incorporate any of these variables into the default methodology, except variation in estimated fertilizer application rates and estimated areas of forested land receiving N fertilizer. All forest soils are treated equivalently under this methodology. Furthermore, only synthetic N fertilizers are captured, so applications of organic N fertilizers are not estimated. However, the total quantity of organic N inputs to soils is included in the Agricultural Soil Management and *Settlements Remaining Settlements* sections.

Uncertainties exist in the fertilization rates, annual area of forest lands receiving fertilizer, and the emission factors. Fertilization rates were assigned a default level[126] of uncertainty at ±50 percent, and area receiving fertilizer was assigned a ±20 percent according to expert knowledge (Binkley 2004). IPCC (2006) provided estimates for the uncertainty associated with direct N_2O emission factor for synthetic N fertilizer application to soils. Quantitative uncertainty of this source category was estimated through the IPCC-recommended Tier 2 uncertainty estimation

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[126] Uncertainty is unknown for the fertilization rates so a conservative value of ±50 percent was used in the analysis.

methodology. The uncertainty ranges around the 2005 activity data and emission factor input variables were directly applied to the 2012 emissions estimates.

Cropland Remaining Cropland

The uncertainty analysis descriptions in this section correspond to source categories included in the Cropland Remaining Cropland sub-chapter of Land Use, Land-Use Change, and Forestry Chapter of the Inventory.

Agricultural Soil Carbon Stock Change

Uncertainty associated with the *Cropland Remaining Cropland* land-use category was addressed for changes in agricultural soil C stocks (including both mineral and organic soils). Uncertainty estimates are presented in Table 7-22 in the main Inventory document for each subsource (mineral soil C stocks and organic soil C stocks) and method that was used in the inventory analysis (i.e., Tier 2 and Tier 3). Uncertainty for the portions of the Inventory estimated with Tier 2 and 3 approaches was derived using a Monte Carlo approach (see Annex 3.12 for further discussion). Uncertainty estimates from each approach were combined using the error propagation equation in accordance with IPCC (2006). The combined uncertainty was calculated by taking the square root of the sum of the squares of the standard deviations of the uncertain quantities.

CO_2 Emissions from Agricultural Liming

Uncertainty regarding limestone and dolomite activity data inputs was estimated at ±15 percent and assumed to be uniformly distributed around the inventory estimate (Tepordei 2003b, Willett 2013b). Analysis of the uncertainty associated with the emission factors included the following: the fraction of agricultural lime dissolved by nitric acid versus the fraction that reacts with carbonic acid, and the portion of bicarbonate that leaches through the soil and is transported to the ocean. Uncertainty regarding the time associated with leaching and transport was not accounted for, but should not change the uncertainty associated with CO_2 emissions (West 2005). The uncertainties associated with the fraction of agricultural lime dissolved by nitric acid and the portion of bicarbonate that leaches through the soil were each modeled as a smoothed triangular distribution between ranges of zero percent to 100 percent. The uncertainty surrounding these two components largely drives the overall uncertainty estimates reported below. More information on the uncertainty estimates for Liming of Agricultural Soils is contained within the Uncertainty Annex.

CO_2 Emissions from Urea Fertilization

A Tier 2 Monte Carlo analysis was completed. The largest source of uncertainty was the default emission factor, which assumes that 100 percent of the C in $CO(NH_2)_2$ applied to soils is ultimately emitted into the environment as CO_2. This factor does not incorporate the possibility that some of the C may be retained in the soil. The emission estimate is, therefore, likely to be high. In addition, each urea consumption data point has an associated uncertainty. Urea for non-fertilizer use, such as aircraft deicing, may be included in consumption totals; it was determined through personal communication with Fertilizer Regulatory Program Coordinator David L. Terry (2007), however, that this amount is most likely very small. Research into aircraft deicing practices also confirmed that urea is used minimally in the industry; a 1992 survey found a known annual usage of approximately 2,000 tons of urea for deicing; this would constitute 0.06 percent of the 1992 consumption of urea (EPA 2000). Similarly, surveys conducted from 2002 to 2005 indicate that total urea use for deicing at U.S. airports is estimated to be 3,740 MT per year, or less than 0.07 percent of the fertilizer total for 2007 (Itle 2009). Lastly, there is uncertainty surrounding the assumptions behind the calculation that converts fertilizer years to calendar years.

Land Converted to Cropland

Uncertainty analysis for mineral soil C stock changes using the Tier 3 and Tier 2 approaches were based on the same method described for *Cropland Remaining Cropland*. The uncertainty for annual C emission estimates from drained organic soils in *Land Converted to Cropland* was estimated using the Tier 2 approach, as described in the *Cropland Remaining Cropland* section.

Uncertainty for the portions of the Inventory estimated with Tier 2 and 3 approaches was derived using a Monte Carlo approach (see Annex 3.12 for further discussion). Uncertainty estimates from each approach were combined using the error propagation equation in accordance with IPCC (2006), i.e., by taking the square root of the sum of the squares of the standard deviations of the uncertain quantities.

Grassland Remaining Grassland

Uncertainty for the portions of the Inventory estimated with Tier 2 and 3 approaches was derived using a Monte Carlo approach (see Annex 3.12 for further discussion). Uncertainty estimates from each approach were combined using the error propagation equation in accordance with IPCC (2006), i.e., by taking the square root of the sum of the squares of the standard deviations of the uncertain quantities.

Land Converted to Grassland

Uncertainty for the portions of the Inventory estimated with Tier 2 and 3 approaches was derived using a Monte Carlo approach (see Annex 3.12 for further discussion). Uncertainty estimates from each approach were combined using the error propagation equation in accordance with IPCC (2006) (i.e., by taking the square root of the sum of the squares of the standard deviations of the uncertain quantities).

Wetlands Remaining Wetlands

The uncertainty analysis descriptions in this section correspond to source categories included in the Wetlands Remaining Wetlands sub-chapter of Land Use, Land-Use Change, and Forestry Chapter of the Inventory.

Peatlands Remaining Peatlands

The uncertainty associated with peat production data was estimated to be ± 25 percent (Apodaca 2008) and assumed to be normally distributed. The uncertainty associated with peat production data stems from the fact that the USGS receives data from the smaller peat producers but estimates production from some larger peat distributors. The peat type production percentages were assumed to have the same uncertainty values and distribution as the peat production data (i.e., ± 25 percent with a normal distribution). The uncertainty associated with the Alaskan reported production data was assumed to be the same as the lower 48 states, or ± 25 percent with a normal distribution. It should be noted that the Alaska Department of Natural Resources estimates that around half of producers do not respond to their survey with peat production data; therefore, the production numbers reported are likely to underestimate Alaska peat production (Szumigala 2008). The uncertainty associated with the average bulk density values was estimated to be ± 25 percent with a normal distribution (Apodaca 2008). IPCC (2006) gives uncertainty values for the emissions factors for the area of peat deposits managed for peat extraction based on the range of underlying data used to determine the emission factors. The uncertainty associated with the emission factors was assumed to be triangularly distributed. The uncertainty values surrounding the C fractions were based on IPCC (2006) and the uncertainty was assumed to be uniformly distributed. Based on these values and distributions, a Monte Carlo (Tier 2) uncertainty analysis was applied to estimate the uncertainty of CO_2 and N_2O emissions from *Peatlands Remaining Peatlands*.

Settlements Remaining Settlements

The uncertainty analysis descriptions in this section correspond to source categories included in the Settlements Remaining Settlements sub-chapter of Land Use, Land-Use Change, and Forestry Chapter of the Inventory.

Changes in Carbon Stocks in Urban Trees

Uncertainty associated with changes in C stocks in urban trees includes the uncertainty associated with urban area, percent urban tree coverage, and estimates of gross and net C sequestration for each of the 50 states and the District of Columbia. A 10 percent uncertainty was associated with urban area estimates based on expert judgment. Uncertainty associated with estimates of percent urban tree coverage for each of the 50 states was based on standard error estimates reported by Nowak and Greenfield (2012). Uncertainty associated with estimate of percent urban tree coverage for the District of Columbia was based on the standard error estimate reported by Nowak et al. (2013). Uncertainty associated with estimates of gross and net C sequestration for each of the 50 states and the District of Columbia was based on standard error estimates for each of the state-level sequestration estimates reported by Nowak et al. (2013). These estimates are based on field data collected in each of the 50 states and the District of Columbia, and uncertainty in these estimates increases as they are scaled up to the national level.

Additional uncertainty is associated with the biomass equations, conversion factors, and decomposition assumptions used to calculate C sequestration and emission estimates (Nowak et al. 2002). These results also exclude changes in soil C stocks, and there may be some overlap between the urban tree C estimates and the forest tree C estimates. Due to data limitations, urban soil flux is not quantified as part of this analysis, while reconciliation of urban tree and forest tree estimates will be addressed through the land-representation effort described in the Planned Improvements section of this chapter.

Direct N2O Fluxes from Settlement Soils

The amount of N_2O emitted from settlements depends not only on N inputs and fertilized area, but also on a large number of variables, including organic C availability, oxygen gas partial pressure, soil moisture content, pH, temperature, and irrigation/watering practices. The effect of the combined interaction of these variables on N_2O flux is complex and highly uncertain. The IPCC default methodology does not explicitly incorporate any of these variables, except variations in fertilizer N and sewage sludge application rates. All settlement soils are treated equivalently under this methodology.

Uncertainties exist in both the fertilizer N and sewage sludge application rates in addition to the emission factors. Uncertainty in fertilizer N application was assigned a default level of ±50 percent.[127] Uncertainty in the amounts of sewage sludge applied to non-agricultural lands and used in surface disposal was derived from variability in several factors, including: (1) N content of sewage sludge; (2) total sludge applied in 2000; (3) wastewater existing flow in 1996 and 2000; and (4) the sewage sludge disposal practice distributions to non-agricultural land application and surface disposal. Uncertainty in the emission factors was provided by the IPCC (2006).

Other

The uncertainty analysis descriptions in this section correspond to source categories included in the Other sub-chapter of Land Use, Land-Use Change, and Forestry Chapter of the Inventory.

Changes in Yard Trimming and Food Scrap Carbon Stocks in Landfills

The uncertainty analysis for landfilled yard trimmings and food scraps includes an evaluation of the effects of uncertainty for the following data and factors: disposal in landfills per year (tons of C), initial C content, moisture content, decay rate, and proportion of C stored. The C storage landfill estimates are also a function of the composition of the yard trimmings (i.e., the proportions of grass, leaves and branches in the yard trimmings mixture). There are respective uncertainties associated with each of these factors.

Waste

The uncertainty analysis descriptions in this section correspond to source categories included in the Waste Chapter of the Inventory.

Landfills

Several types of uncertainty are associated with the estimates of CH_4 emissions from MSW and industrial waste landfills. The primary uncertainty concerns the characterization of landfills. Information is not available on two fundamental factors affecting CH_4 production: the amount and composition of waste placed in every MSW and industrial waste landfill for each year of its operation. The SOG survey is the only nationwide data source that compiles the amount of MSW disposed at the state-level. The surveys do not include information on waste composition and there are no comprehensive data sets that compile quantities of waste disposed or waste composition by landfill. Some MSW landfills have conducted detailed waste composition studies, but landfills in the United States are not required to perform these types of studies. The approach used here assumes that the CH_4 generation potential and the rate of decay that produces CH_4, as determined from several studies of CH_4 recovery at MSW landfills, are representative of conditions at U.S. landfills. When this top-down approach is applied at the nationwide level, the uncertainties are assumed to be less than when applying this approach to individual landfills and then aggregating the results to the national level. In other words, this approach may over- and under-estimate CH_4 generation at some landfills if used at the facility-level, but the end result is expected to balance out because it is being applied nationwide. There is also a high degree of uncertainty and variability associated with the first order decay model, particularly when a homogeneous waste composition and hypothetical decomposition rates are applied to heterogeneous landfills (IPCC 2006).

Additionally, there is a lack of landfill-specific information regarding the number and type of industrial waste landfills in the United States. The approach used here assumes that the majority (99 percent) of industrial waste disposed of in industrial waste landfills consists of waste from the pulp and paper and food and beverage industries. However, because waste generation and disposal data are not available in an existing data source for all U.S. industrial waste landfills, we apply a straight disposal factor over the entire time series to the amount of waste generated to determine the amounts disposed.

Aside from the uncertainty in estimating CH_4 generation potential, uncertainty exists in the estimates of the landfill gas oxidized. A constant oxidation factor of 10 percent as recommended by the Intergovernmental Panel on Climate Change (IPCC) for managed landfills is used for both MSW and industrial waste landfills regardless of climate, the type of cover material, and/or presence of a gas collection system. The number of field studies measuring the rate of

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[127] No uncertainty is provided with the USGS fertilizer consumption data (Ruddy et al. 2006) so a conservative ±50% was used in the analysis.

oxidation has increased substantially since the IPCC 2006 Guidelines were published and, as discussed in the Potential Improvements section, efforts are being made to review the literature and revise this value based on recent, peer-reviewed studies.

Another significant source of uncertainty lies with the estimates of CH_4 that are recovered by flaring and gas-to-energy projects at MSW landfills. Three separate databases containing recovery information are used to determine the total amount of CH_4 recovered and there are uncertainties associated with each. The LMOP database and the flare vendor databases are updated annually, while the EIA database has not been updated since 2005 and will essentially be replaced by GHGRP data for a portion of landfills (i.e., those meeting the GHGRP thresholds). To avoid double counting and to use the most relevant estimate of CH_4 recovery for a given landfill, a hierarchical approach is used among the three databases. The EIA data are given precedence because CH_4 recovery was directly reported by landfills, the LMOP data are given second priority because CH_4 recovery is estimated from facility-reported LFGTE system characteristics, and the flare data are given third priority because this database contains minimal information about the flare and no site-specific operating characteristics (Bronstein et al., 2012). The IPCC default value of 10 percent for uncertainty in recovery estimates was used in the uncertainty analysis when metering of landfill gas was in place (for about 64 percent of the CH_4 estimated to be recovered). This 10 percent uncertainty factor applies to 2 of the 3 databases (EIA and LMOP). For flaring without metered recovery data (approximately 34 percent of the CH_4 estimated to be recovered), a much higher uncertainty of approximately 50 percent was used (e.g., when recovery was estimated as 50 percent of the flare's design capacity).

Wastewater Treatment

The overall uncertainty associated with both the 2012 CH_4 and N_2O emission estimates from wastewater treatment and discharge was calculated using the IPCC Good Practice Guidance Tier 2 methodology (2000). Uncertainty associated with the parameters used to estimate CH_4 emissions include that of numerous input variables used to model emissions from domestic wastewater, and wastewater from pulp and paper manufacture, meat and poultry processing, fruits and vegetable processing, ethanol production, and petroleum refining. Uncertainty associated with the parameters used to estimate N_2O emissions include that of sewage sludge disposal, total U.S. population, average protein consumed per person, fraction of N in protein, non-consumption nitrogen factor, emission factors per capita and per mass of sewage-N, and for the percentage of total population using centralized wastewater treatment plants.

References

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ANNEX 8 QA/QC Procedures

8.1. Background

The purpose of this annex is to describe the QA/QC procedures and information quality considerations that are used throughout the process of creating and compiling the U.S. Greenhouse Gas Inventory. This includes evaluation of the quality and relevance of data and models used as inputs into the Inventory; proper management, incorporation, and aggregation of data; and review of the numbers and estimates to ensure that they are as accurate and transparent as possible. Quality control—in the form of both good practices (such as documentation procedures) and checks on whether good practices and procedures are being followed—is applied at every stage of inventory development and document preparation. In addition, quality assurance occurs at two stages—an expert review and a public review. While both phases can significantly contribute to inventory quality, the public review phase is also essential for promoting the openness of the inventory development process and the transparency of the inventory data and methods.

8.2. Purpose

The *Quality Assurance/Quality Control and Uncertainty Management Plan for the U.S. Greenhouse Gas Inventory* (QA/QC Management Plan) guides the process of ensuring inventory quality by describing data and methodology checks, developing processes governing peer review and public comments, and developing guidance on conducting an analysis of the uncertainty surrounding the emission estimates. The QA/QC Management Plan procedures also stress continual improvement, providing for corrective actions that are designed to improve the inventory estimates over time.

Key attributes of the QA/QC Management Plan are summarized in Figure A- 22. These attributes include:

- *Procedures and Forms:* detailed and specific systems that serve to standardize the process of documenting and archiving information, as well as to guide the implementation of QA/QC and the analysis of uncertainty
- *Implementation of Procedures:* application of QA/QC procedures throughout the whole inventory development process from initial data collection, through preparation of the emission estimates, to publication of the Inventory
- *Quality Assurance:* expert and public reviews for both the inventory estimates and the Inventory report (which is the primary vehicle for disseminating the results of the inventory development process)
- *Quality Control*: consideration of secondary data and source-specific checks (Tier 2 QC) in parallel and coordination with the uncertainty assessment; the development of protocols and templates, which provides for more structured communication and integration with the suppliers of secondary information
- *Tier 1 (general) and Tier 2 (source-specific) Checks:* quality controls and checks, as recommended by *IPCC Good Practice Guidance*
- *Record Keeping:* provisions to track which procedures have been followed, the results of the QA/QC, uncertainty analysis, and feedback mechanisms for corrective action based on the results of the investigations which provide for continual data quality improvement and guided research efforts
- *Multi-Year Implementation*: a schedule for coordinating the application of QA/QC procedures across multiple years
- *Interaction and Coordination:* promoting communication within the EPA, across Federal agencies and departments, state government programs, and research institutions and consulting firms involved in supplying data or preparing estimates for the Inventory. The QA/QC Management Plan itself is intended to be revised and reflect new information that becomes available as the program develops, methods are improved, or additional supporting documents become necessary.

In addition, based on the national QA/QC Management Plan for the Inventory, source-specific QA/QC plans have been developed for a number of sources. These plans follow the procedures outlined in the national QA/QC plan, tailoring the procedures to the specific text and spreadsheets of the individual sources. For each greenhouse gas emissions source or sink included in this Inventory, a minimum of a Tier 1 QA/QC analysis has been undertaken. Where QA/QC activities for a particular source go beyond the minimum Tier 1 level, further explanation is provided within the respective source category text.

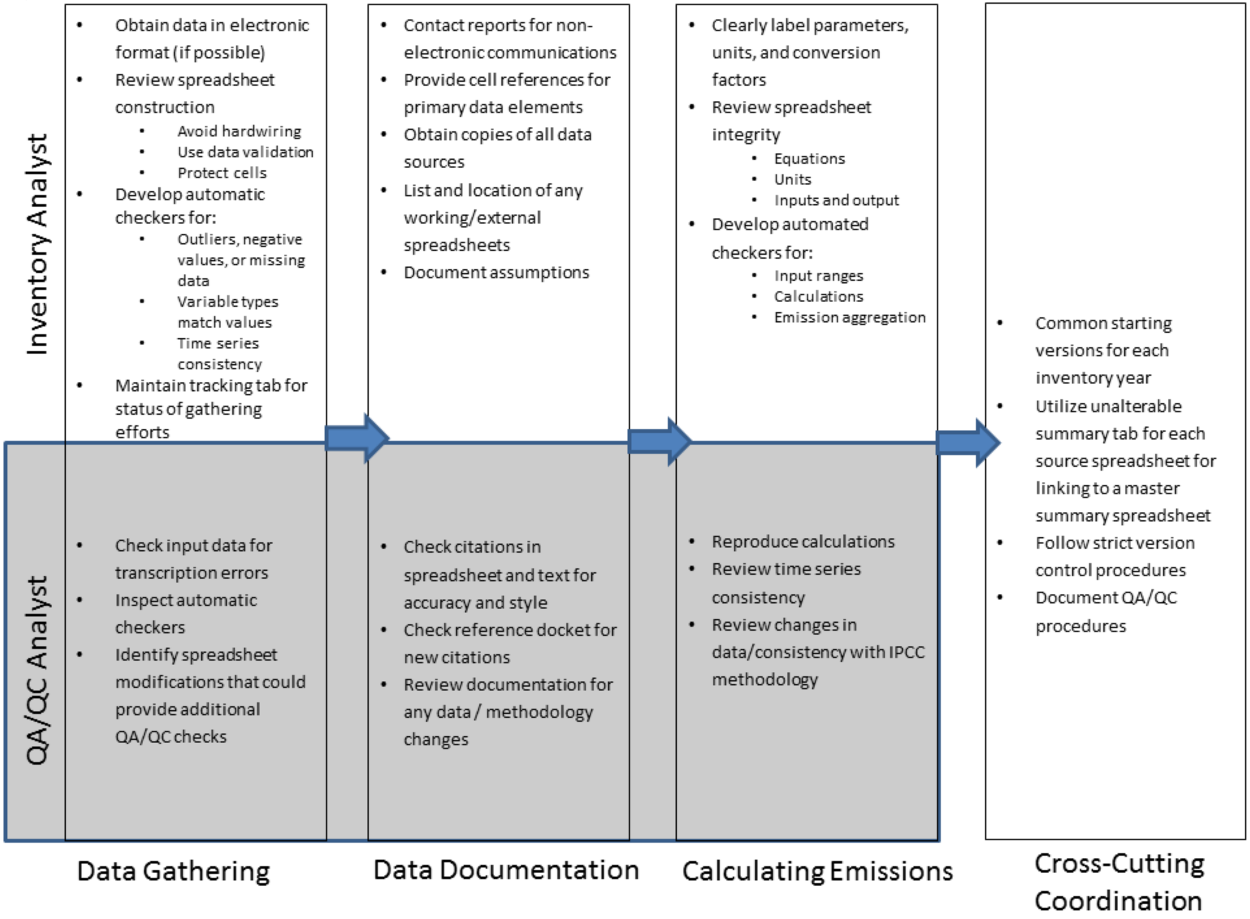
Figure A- 22: U.S. QA/QC Plan Summary

8.3. Assessment Factors

The U.S. Greenhouse Gas Inventory development process follows guidance outlined in EPA's G*uidelines for Ensuring and Maximizing the Quality, Objectivity, Utility, and Integrity, of Information Disseminated by the Environmental Protection Agency*[128] and *A Summary of General Assessment Factors for Evaluating the Quality of Scientific and Technical Information*.[129] This includes evaluating the data and models used as inputs into the U.S. Greenhouse Gas Inventory against the five general assessment factors: soundness, applicability and utility, clarity and completeness, uncertainty and variability, evaluation and review. Table A- 291 defines each factor and explains how it was considered during the process of creating the current Inventory.

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[128] EPA report #260R-02-008, October 2002, available at www.epa.gov/quality/informationguidelines

[129] EPA report #100/B-03/001, June 2003, available at www.epa.gov/stpc/assess.htm

Table A- 291: Assessment Factors and Definitions

General Assessment Factor	Definition	How the Factor was Considered
Soundness (AF1)	The extent to which the scientific and technical procedures, measures, methods or models employed to generate the information are reasonable for, and consistent with, the intended application.	The intended application is to provide information regarding all sources and sinks of greenhouse gases in the United States for the Inventory year, as required per UNFCCC Annex I country reporting requirements. The underlying data, methodology, and models used to generate the U.S. Greenhouse Gas Inventory are reasonable for and consistent with their intended application. The U.S. emissions calculations follow IPCC Guidelines developed specifically for UNFCCC inventory reporting. They are based on the best available, peer-reviewed scientific information, and have been used by the international community for over 20 years. When possible, Tier 2 and Tier 3 methodologies from the IPCC Guidelines are applied to calculate more accurate United States emissions.
Applicability and Utility (AF2)	The extent to which the information is relevant for the Agency's intended use.	The Inventory's underlying data, methodology, and models are relevant for their intended application because they generate the sector-specific greenhouse gas emissions trends necessary for assessing and understanding all sources and sinks of greenhouse gases in the United States for the Inventory year. They are relevant for communicating U.S. emissions information to domestic audiences, and they are consistent with IPCC Guidelines developed specifically for UNFCCC reporting purposes of international greenhouse gas inventories.
Clarity and Completeness (AF3)	The degree of clarity and completeness with which the data, assumptions, methods, quality assurance, sponsoring organizations and analyses employed to generate the information are documented.	The methodological and calculation approaches applied to generate the U.S. Greenhouse Gas Inventory are extensively documented in the IPCC Guidelines. The U.S. Greenhouse Gas Inventory report describes its adherence to the IPCC Guidelines, and the U.S. Government agencies providing data to implement the IPCC Guidelines approaches. Any changes made to calculations, due to updated data and methods, are explained and documented in the report consistent with UNFCCC reporting guidelines.
Uncertainty and Variability (AF4)	The extent to which the variability and uncertainty (quantitative and qualitative) in the information or in the procedures, measures, methods or models are evaluated and characterized.	In accordance with IPCC Guidelines, the uncertainty associated with the Inventory's underlying data, methodology, and models was evaluated by running a Monte-Carlo uncertainty analysis on source category emissions data to produce a 95 percent confidence interval for the annual greenhouse gas emissions for that source. To develop overall uncertainty estimates, the Monte Carlo simulation output data for each emission source category uncertainty analysis were combined by type of gas, and the probability distributions

		were fitted to the combined simulation output data where such simulated output data were available. The evaluation of uncertainties for the underlying data is documented in an Uncertainty section of the Annex to the U.S. Greenhouse Gas Inventory.
Evaluation and Review (AF5)	The extent of independent verification, validation and peer review of the information or of the procedures, measures, methods or models.	The majority of the underlying methodology, calculations, and models used to generate the U.S. Greenhouse Gas Inventory have been independently verified and peer reviewed as part of their publication in the IPCC Guidelines. In cases where the methodology differs slightly from the IPCC Guidelines, these were independently verified and validated by technical experts during an annual expert review phase of the Inventory report. For the data used in calculating greenhouse gas emissions for each source, multiple levels of evaluation and review occur. Data are compared to results from previous years, and calculations and equations are continually evaluated and updated as appropriate. Throughout the process, inventory data and methodological improvements are planned and incorporated. The Inventory undergoes annual cycles of expert and public review before publication. This process ensures that both experts and the general public can review each source of emissions and have an extended opportunity to provide feedback on the methodologies used, calculations, data sources, and presentation of information.